



FILED

11/04/22

04:59 PM

A2106021

**BEFORE THE PUBLIC UTILITIES COMMISSION
OF THE STATE OF CALIFORNIA**

Application of Pacific Gas and Electric Company for
Authority, Among Other Things, to Increase Rates and
Charges for Electric and Gas Service Effective on
January 1, 2023.

(U 39 M)

Application No. 21-06-021

**PACIFIC GAS AND ELECTRIC COMPANY'S (U39M)
OPENING BRIEF**

MARY A. GANDESBERY
CHARLES MIDDLEKAUFF
WALKER A. MATTHEWS

Law Department
PACIFIC GAS AND ELECTRIC COMPANY
Post Office Box 7442
San Francisco, California 94120
Telephone: (510) 316-3566
Fax: (415) 973-5520
E-Mail: mary.gandesbery@pge.com

Attorneys for
PACIFIC GAS AND ELECTRIC COMPANY

Dated: November 4, 2022

TABLE OF CONTENTS

	Page
1. INTRODUCTION AND SUMMARY OF RECOMMENDATIONS	1
1.1 Policy Overview: PG&E Must Have Adequate Funding To Provide Safe And Reliable Service	1
1.2 Summary Of Recommendations	3
1.2.1 Addressing Risks In Our Electric Distribution System	3
1.2.1.1 Community Wildfire Safety Program	3
1.2.1.2 Other Electric Distribution Investments	3
1.2.2 Addressing Risk In Our Gas Operations	4
1.2.3 Building A Safe And Dependable Energy Supply	5
1.2.4 Customer And Communications Proposals To Improve Service, Billing And Communications	5
1.2.5 Excess Liability Insurance	6
1.3 Affordability And Customer Impacts	7
1.3.1 Affordability Generally	7
1.3.2 The Affordability Metrics Data, While Informative, Should Not Be Used To Cap The Revenue Requirement Needed To Provide Safe And Reliable Service	9
1.4 Legal And Ratemaking Principles	11
1.4.1 Burden And Standard of Proof	11
1.4.2 Ratemaking	14
1.4.2.1 Legal Issues	14
1.4.2.2 Utility Rate Components	17
1.4.2.3 Results Of Operations Model	17
1.5 Use Of PG&E's 2021 Forecast And Recorded Cost Data	18
1.5.1 Uncontested Expense	21
1.5.2 Uncontested Capital	21
1.5.3 Uncontested Non-Forecast Issues, Balancing Accounts, And Memorandum Accounts	22
1.6 Other General Issues	22
1.6.1 Inclusion Of Initial And Update Testimony Forecasts	22
1.6.2 Disputed Balancing And Memorandum Accounts	23
1.6.3 Glossary	23

TABLE OF CONTENTS

(continued)

	Page
1.6.4 Stipulated Outcomes.....	23
1.6.5 Length Of Brief	24
2. RISK MANAGEMENT, SAFETY, OPERATING RHYTHM AND CLIMATE (EXHIBIT PG&E-02).....	25
2.1 Enterprise Risk Management.....	25
2.1.1 Enterprise Risk Management And Policy	25
2.1.1.1 PG&E’s Enterprise Risk Organization	25
2.1.1.2 The Commission’s Risk-Based Decision-Making Framework	26
2.1.1.3 PG&E’s Risk-Informed Investment Prioritization Process	29
2.1.2 Integrating RAMP Into The GRC	30
2.2 Risk Modeling Issues.....	31
2.2.1 PG&E’s MAVF Implementation Is Reasonable	31
2.2.2 PG&E’s Use Of Tranches Is Reasonable	33
2.2.3 TURN’s Analysis Of Operational Failure Is Not Correct	34
2.3 Risk Spend Efficiency.....	36
2.3.1 The Commission Should Not Adopt TURN’s Flawed Proposal To Convert RSEs Into Benefit-Cost Ratios.....	37
2.3.2 The Commission Should Not Reject Funding For Gas Safety Programs Due To Their Low RSEs.....	43
2.3.3 The Commission Should Not Order PG&E To Calculate RSEs For All MAT Codes In Our Next GRC	44
2.4 Safety Policy and Strategy	46
2.4.1 Everyone And Everything Is Always Safe.....	46
2.4.2 Workforce Safety Programs	46
2.4.3 Public Safety Programs	46
2.4.4 PG&E Operates At High Levels Of Safety Consistent With Legal And Regulatory Requirements And Commission Oversight	48
2.4.5 Parties Propose Deep Spending Cuts In Safety Program Funding.....	49
2.4.5.1 Party Proposals To Reduce Electric Safety Spending	50
2.4.5.2 Party Proposals To Cut Gas Safety Programs.....	52

TABLE OF CONTENTS

(continued)

	Page
2.5 Planning, Work Prioritization And Financial Issues.....	54
2.5.1 Operating Rhythm	54
2.5.2 Deferred Work And Spending Accountability Issues	55
2.5.2.1 PG&E Has An Obligation To Reprioritize Funding To Provide Safe And Reliable Service.....	55
2.5.2.2 Deferred Work Analysis And Showing In PG&E’s 2023 GRC	57
2.5.2.3 The Deferred Work Settlement Should Be Discontinued.....	59
2.5.2.4 The Deferred Work Settlement Should Not Be Revised To Require Reprioritization Decisions Be Justified Based On RSE Scores.....	62
2.5.3 PG&E’s Financial Health.....	63
2.5.3.1 The Commission Should Not Delay Cost Recovery For Appropriate Forecast Business Expenses.	64
2.5.3.2 The Commission Should Approve Funding For Costs Of Service And Not Require “Shareholder Contributions” For Ordinary Operating Expenses.....	66
2.5.3.3 The Commission Should Not Adopt Policies That Encourage Use Of Debt To Finance Permanent Assets.....	68
2.5.3.4 The Commission Should Deny TURN’s Unlawful and Unsubstantiated Proposals To Establish A GRC Revenue Requirement Based on the Consumer Price Index	72
2.6 Climate Resilience	78
3. GAS OPERATIONS (EXHIBIT PG&E-03).....	80
3.1 Expense and Capital Forecast	81
3.2 Gas Operations Risk Management.....	83
3.2.1 Overview of Gas Operations Risk Management Testimony	83
3.2.1.1 Risk Management Organizational Structure and Governance	83
3.2.1.2 Risk Management Process and Tools	84
3.2.1.3 Gas Operations Risk Events.....	85
3.2.2 TURN’s Issues Regarding Gas Operations Risk Management.....	86

TABLE OF CONTENTS (continued)

	Page
3.2.2.1 The Gas Operations Risk Model Tranches Are Reasonable	87
3.2.2.2 Reducing Gas Operations’ Forecast Based Solely On RSE Scores Is Not Justified	91
3.2.2.3 PG&E Responded Appropriately To SPD’s Comments On PG&E’s 2020 RAMP Report.....	91
3.2.2.4 An RSE Was Not Required To Be Computed For The Meter Protection Program.....	92
3.3 Asset Family – Distribution Mains and Services.....	92
3.3.1 Fitting Mitigation Program – Expense	94
3.3.1.1 The Pace of the Fittings Mitigation Program Is Appropriate	95
3.3.1.2 PG&E’s Unit Cost is Reasonable	96
3.3.1.3 Mitigation of the Plastic Fusion Fittings was not Previously Funded	97
3.3.1.4 The Fitting Mitigation Program Should Be Funded	97
3.3.2 Cross Bore Program – Expense (MAT JQK)	99
3.3.2.1 Cross Bores Outside San Francisco Pose a Significant Risk	100
3.3.2.2 The Rate of Cross Bore Finds	101
3.3.2.3 PG&E’s Unit Cost Forecast is Reasonable.....	101
3.3.3 Gas Pipeline Replacement Program	102
3.3.3.1 PG&E Appropriately Prioritizes Steel Pipe Replacement.....	104
3.3.3.2 TURN’s Proposed Reduction in Pace Is Imprudent	105
3.3.3.3 PG&E Has Supported its GPRP Proposal	107
3.3.4 Plastic Pipe Replacement Program – Capital (MAT 14D).....	108
3.3.4.1 All Pre-1985 Aldyl-A Pipe Is Subject to Cracking and Should Be Removed Before Its Expected Failure Date.....	111
3.3.4.2 Aldyl-A Pipe Risks Continue to Grow Over Time	114
3.3.4.3 The Pace of PG&E’s Aldyl-A Pipe Replacement Program Is Justified	115

TABLE OF CONTENTS

(continued)

	Page
3.3.4.4 PG&E Should Prioritize the Highest Risk Plastic Pipe in Accordance With Its DIMP Model	117
3.3.4.5 RSE Scores Are Not a Valid Basis to Drastically Reduce Program Funding	118
3.3.4.6 The Commission’s Ongoing Long-Term Gas System Planning Proceeding Does Not Justify Reducing Program Spending.....	119
3.3.4.7 PG&E Expects To Complete the 417 miles in the 2020- 2022 Aldyl-A Program	122
3.3.4.8 The 2023 Forecast Should Not be Based on 2021 Recorded Costs	122
3.3.4.9 The 2021 and 2022 Forecast Should Not be Based on 2021 Recorded Costs	123
3.3.4.10 The Commission Should Adopt PG&E’s Unit Cost.....	123
3.3.5 Reliability Service Replacement Program – Capital	124
3.3.5.1 Vintage Services Without Records Pose a Risk and Should Be Replaced.....	125
3.3.5.2 Program Funding Should Be Based on PG&E’s Undisputed Unit Cost Forecast	126
3.4 Asset Family – Transmission Pipe.....	126
3.4.1 In-Line Inspections (MWCs 75, 98, and HP).....	128
3.4.1.1 PG&E’s ILI Upgrade Forecast Should Not Be Reduced – Capital (MAT 98C).....	131
3.4.1.2 PG&E’s Unit Cost Forecast for ILI Upgrades Is Reasonable - Capital (MAT 98C)	140
3.4.1.3 Performance Metrics	142
3.4.1.4 PG&E’s Traditional ILI Assessment Forecast Is Reasonable - Expense (MAT HPB)	143
3.4.1.5 PG&E’s Non-Traditional ILI Assessment Forecast Is Reasonable – Expense (MAT HPR)	146
3.4.1.6 PG&E’s ILI Capital Repairs Forecast Is Reasonable – Capital (MAT 75P)	146
3.4.1.7 PG&E’s Forecast for DE&R Expense Associated With ILI Assessments Is Reasonable – Expense (MAT HPI)	147
3.4.2 Direct Assessment (MWC HP)	149

TABLE OF CONTENTS (continued)

	Page
3.4.2.1 ECDA Indirect Inspections – Expense (MAT HPC)	149
3.4.2.2 ECDA Direct Examination – Expense (MAT HPN)	150
3.4.2.3 ICDA Engineering – Expense (MAT HPJ)	152
3.4.2.4 ICDA Digs – Expense (MAT HPO)	153
3.4.2.5 SCCDA Engineering and Surveys – Expense (MAT HPK)	156
3.4.2.6 SCCDA Digs – Expense (MAT HPP)	157
3.4.2.7 TIMP Direct Examinations – Expense (MAT HPU)	159
3.4.3 Strength Testing (MWCs HP and 75)	160
3.4.3.1 Non-TIMP Strength Testing – Capital (MAT 75U)	160
3.4.3.2 Non-TIMP Pipeline Replacement in Lieu of Strength Testing – Capital (MAT 75R).....	164
3.4.3.3 Non-TIMP Pipeline Replacement in Lieu of Strength Testing - Expense (MAT JT6)	165
3.4.3.4 TIMP Strength Testing – Expense (MAT HPF)	166
3.4.3.5 TIMP Replacement in Lieu of Strength Testing – Expense (MAT HPM).....	167
3.4.3.6 TIMP Replacement in Lieu of Strength Testing – Capital (MAT 75Q).....	168
3.4.4 Vintage Pipe Replacement – Capital (MWC 75E).....	169
3.4.5 Shallow and Exposed Pipe (Including Water and Levee Crossings) – Capital (MATs 75M, 75T and 75K).....	172
3.4.6 Public Awareness (MAT JT0).....	174
3.4.7 TIMP Balancing and Memorandum Accounts.....	176
3.4.8 ILI Balancing and Memorandum Accounts	179
3.4.9 ICDA Memorandum Account	182
3.5 Asset Family – Facilities.....	183
3.5.1 GT Routine C&P Program – Expense (MAT JTY)	185
3.5.2 GT M&C Terminal Upgrades – Capital (MAT 765)	186
3.5.2.1 The Brentwood Terminal rebuild Will be Used and Useful During the 2023 GRC Period.....	187

TABLE OF CONTENTS

(continued)

	Page
3.5.2.2 PG&E Did Not Underspend On The Brentwood Terminal.....	189
3.5.2.3 There are significant operational and safety risks if the Brentwood Terminal Rebuild does not receive funding	189
3.5.3 GT and GD M&C Station OPP Enhancements Program – Expense and Capital (MATs FHQ, JTX, 50N and 76G).....	190
3.5.3.1 The OPP Enhancement Program’s Operational Risk Drivers Are Undisputed	193
3.5.3.2 The OPP Program Is Not Addressing “Relatively Lower Risk Assets”	195
3.5.4 HPR Program – Capital (MWC 2K)	196
3.5.5 GT C&P Compressor Replacements and Retirements: Los Medanos Compressor Replacement (MAT 76X).....	199
3.5.5.1 The Los Medanos Compressor Project is Not Deferred Work	202
3.5.5.2 The Los Medanos Compressor Is Needed	205
3.5.6 GT C&P Compressor Replacements and Retirements: Tionesta Compressor Station Retirement (MAT 76X)	205
3.6 Asset Family - Storage.....	207
3.6.1 Uncertainty in Gas Storage Regulations and Rules.....	209
3.6.2 PG&E’s Updated Peak Day Supply Standard	211
3.6.2.1 Updating the Peak Day Supply Standard for the 2023 GRC	212
3.6.2.2 PG&E’s Forecasts Are Not Outdated	214
3.6.2.3 Core Demand Forecast.....	215
3.6.2.4 Electric Generation Demand Forecast	218
3.6.2.5 PG&E’s Peak Day Supply Standard Should Be Approved.....	223
3.6.3 Hourly Curtailment.....	224
3.6.3.1 PG&E Considered Hourly Curtailments Related to Reserve Capacity In Its Opening Testimony	225
3.6.3.2 Hourly Curtailments Cannot Replace Reserve Capacity	226
3.6.3.3 Hourly Curtailments Do Not Justify Eliminating Los Medanos.....	230

TABLE OF CONTENTS
(continued)

	Page
3.6.4 Retention of Los Medanos, Drilling New Wells and Cross Compression	232
3.6.4.1 The Retention of Los Medanos, Drilling New Wells, And Cross-Compression Are Necessary	233
3.6.4.2 ISP Capacity Is Not A Reasonable Substitute for Los Medanos	236
3.6.4.3 Wild Goose and LGS Raises Issues That Are Red Herrings.....	239
3.6.4.4 Work at Los Medanos Is Critical and Time Sensitive	242
3.6.5 Well Drilling – Capital (MAT 3L1)	243
3.6.6 Well Reworks/Retrofits – Capital (MAT 3L3)	246
3.6.6.1 The Number of Reworks Forecast Should Not Be Reduced.....	247
3.6.6.2 PG&E’s Unit Cost Forecast is Reasonable	249
3.6.7 Controls and Monitoring – Capital (MAT 3L5).....	251
3.6.8 Well Integrity Assessments – Expense (MAT AH1)	252
3.6.9 Well Reworks – Expense (MAT AH2)	253
3.6.10 Gas Storage Balancing Account.....	257
3.7 Gas Operations and Maintenance	260
3.7.1 Locate and Mark – Expense (MAT DFA).....	262
3.7.1.1 PG&E’s Forecast of 12 Percent Growth is Reasonable.....	264
3.7.1.2 PG&E’s Unit Cost is Reasonable	266
3.7.2 Standby Governance – Expense (MAT DFB).....	267
3.7.2.1 PG&E’s GD Standby Governance Forecast is Reasonable	268
3.7.2.2 PG&E’s GT Standby Governance Forecast is Reasonable	269
3.7.3 Meter Protection Program (MAT EXB).....	270
3.7.3.1 Delaying MPP Remediation Will Result in a Backlog of Meters	272
3.7.3.2 Cal Advocates Understates the CGI Population	274
3.7.3.3 Cal Advocates Understates the Rate of New MPP Finds	275

TABLE OF CONTENTS
(continued)

	Page
3.7.3.4 Cal Advocates Understates MPP Existing Location Units.....	276
3.7.3.5 Cal Advocates Ignores MPP Customer Call In Units.....	277
3.7.4 Relocation of Meter Sets – Capital (MAT 27A)	278
3.8 Gas Operations Corrosion Control.....	279
3.8.1 GD Atmospheric Corrosion Mitigation – Mains (MAT FHL).....	281
3.8.2 GD Atmospheric Corrosion Mitigation – Services (MAT FHM)	284
3.8.3 GD Capital Corrosion Control (MATs 50D/50Q).....	286
3.8.4 GT&S Corrosion Control Capital Expenditures (MAT 3K1, 3K4, 3K9).....	289
3.8.5 The Internal Corrosion Balancing Account (ICBA)	290
3.9 Gas Operations Leak Management.....	290
3.9.1 Below Ground Distribution Main Leak Repair (MAT FIG)	292
3.9.1.1 PG&E’s Leak Find Rate is Reasonable	292
3.9.1.2 PG&E’s 2023 Forecasted Unit Cost Is Reasonable.....	293
3.9.2 Distribution Meter Set Leak Repair (MAT FIS)	294
3.9.2.1 PG&E’s Forecasted Units Are Reasonable.....	295
3.9.2.2 PG&E’s 2023 Forecasted Unit Cost Is Reasonable.....	297
3.9.3 Below Ground Distribution Service Replacement (MAT 50G).....	298
3.9.4 Transmission Leak Repair (MAT JOP).....	300
3.9.4.1 PG&E’s Forecast of Grade 3 Transmission Leak Repairs Is Reasonable	300
3.9.4.2 PG&E’s Proposed Unit Cost is Reasonable.....	301
3.9.5 New Environmental Regulations Balancing Account (NERBA).....	302
3.10 Gas System Operations	302
3.10.1 Gas Distribution Control Center (GDCC) Operations (MAT FGA).....	304
3.10.1.1 Cal Advocates’ Proposed Reduction Includes Erroneous Costs	305
3.10.1.2 Costs Associated with PG&E’s Consolidation Plan Are Recoverable.....	306

TABLE OF CONTENTS

(continued)

	Page
3.10.1.3 The SCADA Predictive Health Analytics Work Is Reasonable	307
3.10.2 Gas Distribution Manual Field Operations – Expense (MAT FGB)	308
3.10.3 GT&S Operations (MAT CMA)	309
3.10.3.1 The Gas Control Room Consolidation Forecast is Reasonable	310
3.10.3.2 SCADA Predictive Health Analytics.....	311
3.10.3.3 Hiring Additional Gas Transmission System Planning Employees is Reasonable.....	311
3.10.4 Electric Power for Compressor Fuel and Other Electric Equipment (MAT CMB)	312
3.10.5 Gas Distribution SCADA Visibility Program – Remote Terminal Units – Capital (MAT 4AM).....	314
3.10.5.1 The SCADA Visibility Program Is Reasonable and Prudent	315
3.10.5.2 The Remaining Proposed SCADA Installations Are Necessary	317
3.10.5.3 RSE Scores Should Not Be The Sole Criteria For this Program.....	318
3.10.6 Gas Transmission SCADA Visibility Program – Capital (MAT 76M)	319
3.10.6.1 The SCADA Visibility Program Is Reasonable and Prudent	320
3.10.6.2 Visibility Into Local Transmission Conditions is Critical.....	321
3.10.6.3 RSE Scores Should Not Be The Sole Criteria For this Program.....	321
3.10.7 Gas Transmission Capacity for Load Growth – Capital (MAT 73A).....	322
3.10.7.1 PG&E’s Forecast is Reasonable	323
3.10.7.2 PG&E Cannot Ignore the Need for Additional Capacity Projects.....	325
3.11 Gas Technology	327
3.12 Other Gas Operations Support	328

TABLE OF CONTENTS (continued)

	Page
3.12.1 Butte Rebuild – Capital and Expense (MAT LXA and MAT 3QA)	330
3.12.2 CEMA Straight Time Labor Program – Expense and Capital (MAT 21# and AB #)	332
3.12.3 Gas R&D and Deployment – Expense (MAT GZA)	334
3.12.4 Other Gas Operations Support (MAT AB#)	336
3.12.5 StanPac -- Expense (MAT 34A).....	337
3.12.6 StanPac -- Capital (MAT 44A).....	338
3.13 New Business and Work at the Request of Others	340
3.13.1 Gas Transmission Expense Work at the Request of Others – Expense (MAT Code JTA).....	341
3.13.2 Gas Distribution Capital New Business Program – Capital (MWC 29).....	344
3.13.2.1 A Revised Forecast Should Be Adopted Given the Commission’s Gas Allowance Decision.....	348
3.13.2.2 The Commission Should Clarify the Cost Recovery Process for Non-Residential Projects Approved After July 1, 2023	351
3.13.2.3 TURN’s approach to Determining the Number of Residential Permits is Flawed	351
3.13.3 Gas Transmission (GT) New Business (NB) Program – Capital (MAT 26A).....	352
3.13.4 Gas Transmission Work at the Request of Others Program – Capital (MAT 83A)	354
3.14 Ratemaking	356
3.14.1 Gas Storage Balancing Account (GSBA).....	356
3.14.2 Transmission Integrity Management Plan Balancing Account (TIMPBA)	356
3.14.3 Other Balancing and Memorandum Accounts	356
3.14.3.1 In-Line Inspection Memorandum Account (ILIMA) and Internal Corrosion Direct Assessment Memorandum Account (ICDAMA)	356
3.14.3.2 The Internal Corrosion Balancing Account (ICBA).....	356

TABLE OF CONTENTS
(continued)

	Page
3.14.3.3 New Environmental Regulations Balancing Account (NERBA)	357
3.14.3.4 Undisputed Balancing and Memorandum Accounts	361
3.14.3.5 New Accounts Related To MWC 29	362
4. ELECTRIC DISTRIBUTION (EXHIBIT PG&E-04).....	363
4.1 PG&E Forecast and Overview	363
4.2 Electric Distribution Risk Management.....	365
4.2.1 PG&E’s Wildfire Distribution Risk Model	366
4.2.2 Effectiveness Of PG&E’s System Hardening Programs To Mitigate Wildfire Risk.....	368
4.2.2.1 Overview Of PG&E’s Undergrounding Program Risk Issues.....	368
4.2.2.2 Issues Raised By TURN	369
4.2.2.3 Issues Raised By MGRA	372
4.2.3 Other Electric Distribution Risk Issues Raised By Parties.....	373
4.2.3.1 Public Safety Power Shutoff Risk Modeling.....	373
4.2.3.2 Reliance On PSPS And EPSS To Mitigate Wildfire Risk	374
4.2.3.3 The Role Of RSE Values In Selecting Wildfire Mitigations	375
4.2.3.4 Cal Advocates’ Proposed Capital Forecast Reductions To Emergency Work Based On Its Alternate Risk Analysis Are Unreasonable.....	376
4.3 Wildfire System Hardening	378
4.3.1 Undergrounding.....	380
4.3.1.1 PG&E’s Undergrounding Scope And Pace Of Work Is Reasonable	383
4.3.1.2 PG&E’s Undergrounding Program Is Cost-Effective In Comparison To Alternatives To Achieve The Same Level Of Risk Reduction	389
4.3.1.3 PG&E Is Able To Effectively Address Undergrounding Implementation Challenges	393
4.3.1.4 PG&E’s Unit Cost Targets Are Reasonable And Achievable	402

TABLE OF CONTENTS

(continued)

	Page
4.3.1.5 PG&E Is Committed To Updating Communities And Stakeholders Of Specific Undergrounding Activities.....	405
4.3.1.6 Telecommunication Intervenors’ Objections Are Without Merit.....	407
4.3.1.7 Other Issues.....	412
4.3.2 Overhead System Hardening.....	419
4.3.2.1 The Commission Should Adopt Cal Advocates’ Recommendation For 2021-2023 And Adopt PG&E’s Forecast For 20243-2026	422
4.3.2.2 The Commission Should Reject TURN’s Recommendations As Unsound.....	422
4.3.2.3 AARP’s Proposed Funding Adjustment To Allow For Half Of PG&E’s Original Overhead Hardening Program Delays And Undermines The Risk Reductions.....	427
4.4 Other Community Wildfire Risk Mitigations	428
4.4.1 Situational Awareness and Forecasting.....	429
4.4.2 Public Safety Power Shutoff Operations	429
4.4.2.1 PG&E’s Forecast For Public Safety Power Shutoff Events (MWC AB) Is Reasonable	430
4.4.2.2 PG&E’s Capital Forecast For Public Safety Power Shutoff – Field Ops Tech Capital (MWC 21) Is Reasonable	436
4.4.3 Enhanced Automation and PSPS Impact Mitigations	436
4.4.3.1 PG&E’s Forecasts For Disputed MATs Are Reasonable	438
4.4.3.2 PG&E’s Capital Forecast For Line Sensor (MAT 49I) Is Reasonable	439
4.4.3.3 Distribution Grid Sensor (MWC 49)	441
4.4.4 Community Wildfire Safety Program Project Management Organization (PMO).....	441
4.4.5 Information Technology for Wildfire Mitigations	441
4.4.6 Enhanced Powerline Safety Settings	442
4.5 Emergency Preparedness and Response	445
4.6 Electric Emergency Recovery.....	446
4.6.1 PG&E’s Routine Emergency (MWC 17) Forecast Is Reasonable	448

TABLE OF CONTENTS
(continued)

	Page
4.6.2 PG&E’s Major Emergency (MWC 95 Excluding CESTLBA) Forecast Is Reasonable	450
4.6.3 PG&E’s Proposal to Establish A CEMA Straight Time Labor Balancing Account (MWCs IF and 95) Is Reasonable	451
4.7 Distribution System Operations.....	454
4.8 Field Metering.....	455
4.8.1 Collect Revenue (MWC IU).....	456
4.8.2 Install New Gas Meters (MWC 74).....	457
4.9 Vegetation Management	458
4.9.1 Vegetation Management (MWCs HN and IG).....	459
4.10 Overhead and Underground Electric Asset Inspections	463
4.10.1 Overhead Inspections (MAT BFB)	464
4.11 Overhead and Underground Electric Distribution Maintenance	469
4.11.1 PG&E’s Expense and Capital Forecast And Parties’ Recommendations	470
4.11.2 PG&E’s Forecasted Pace of Work For Capital Programs Is Reasonable And Achievable.....	471
4.11.3 PG&E Appropriately Forecast Costs Based On Recent Costs	473
4.11.4 PG&E’s Forecasts For Disputed MWCs And MATs Are Reasonable.....	474
4.11.4.1 PG&E’s Expense Forecast For Overhead Equipment Replacement (MWC KA) Is Reasonable.....	474
4.11.4.2 PG&E’s Capital Forecast For Overhead Equipment (MWC 2A) Is Reasonable.....	476
4.11.4.3 PG&E’s Capital Forecast For Underground Equipment Replacement (MWC 2B) Is Reasonable	489
4.11.5 Non-Financial Recommendations Regarding RSE Scores.....	492
4.12 Pole Asset Management.....	492
4.12.1 PG&E’s Expense and Capital Forecast	493
4.12.2 PG&E’s Capital Forecast For Install/Replace Overhead Poles (MWC 07) Is Reasonable	494
4.12.2.1 PG&E’s Forecasts For Pole Replacement Programs (MAT 07D, 07O and 07C) Are Reasonable	495

TABLE OF CONTENTS

(continued)

	Page
4.12.3 Cal Advocates' Non-Financial Recommendations	500
4.13 Overhead and Underground Asset Management and Reliability	501
4.13.1 PG&E's Capital Forecast	502
4.13.2 The Commission Should Reject Cal Advocates' Pace-Of-Work Argument.....	502
4.13.3 The Commission Should Reject AARP's Recommendations As Counter To Sound And Prudent Utility Practices	504
4.13.4 PG&E's Capital Forecast For Electric Distribution Overhead Asset Replacement (MWC 08) Is Reasonable	504
4.13.4.1 PG&E's Capital Forecast For Overhead Conductor Replacement Program (MAT 08J) Is Reasonable	505
4.13.4.2 PG&E's Capital Forecast For Grasshopper/Overhead Switch Replacements (MAT 08S) Is Reasonable.....	509
4.13.5 PG&E's Capital Forecast For Distribution Circuit Zone Reliability (MWC 49) Is Reasonable	510
4.13.5.1 PG&E's Capital Forecast For Overhead Fuses (MAT 49C) Is Reasonable	511
4.13.6 PG&E's Capital Forecast For Electric Distribution Underground Asset Replacement (MWC 56) Is Reasonable	512
4.13.6.1 PG&E's Capital Forecast For Reliability Related Cable Replacement (MAT 56A) Is Reasonable.....	513
4.13.6.2 PG&E's Capital Forecast For COE Cable Replacement (MAT 56C) Is Reasonable	515
4.13.6.3 PG&E's Capital Forecast For LBOR Switch Replacement (MAT 56S) Is Reasonable.....	516
4.13.6.4 PG&E's Capital Forecast For Temperature Alarm Devices (MAT 56T) Is Reasonable	518
4.14 Network Asset Management.....	520
4.14.1 PG&E's Expense and Capital Forecast	521
4.14.2 PG&E's Capital Forecast For Install/Replace Network Assets (MWC 2C) and Underground Asset Replacement (MWC 56) Are Reasonable.....	521
4.14.2.1 AARP Misunderstands PG&E's Network System, Network Asset Management Program, And Customer Benefits	523

TABLE OF CONTENTS (continued)

	Page
4.14.2.2 PG&E’s Network Asset Management Activities Are Critical To Maintaining The Current Reliability Of The Network System.....	525
4.14.2.3 PG&E’s Capital Forecast For Network Transformer and Protector Replacement (MAT 2CC) Is Reasonable.....	526
4.14.2.4 PG&E’s Capital Forecast For Network SCADA Safety Monitoring (MAT 2CE) Is Reasonable	529
4.14.2.5 PG&E’s Capital Forecast For Primary Network Cable Replacement Program (MAT 56N) Is Reasonable	532
4.15 Substation Asset Management.....	533
4.15.1 Electric Distribution Substation, Replace Other Equipment (MWC 48)	534
4.15.1.1 Circuit Breaker Replacement – Capital (MAT 48D).....	535
4.15.1.2 Cal Advocates’ Other Recommended Forecast Reductions (MATs 48X, 48C, 48E, 48H, 48N).....	541
4.15.1.3 AARP’s Other Recommended Reductions (MATs 48E and 48L)	543
4.15.1.4 Cal Advocates’ Proposed Disallowance to PG&E’s 2020 Recorded Costs for Switchgear Replacement (MAT 48F) Should Not Be Adopted	544
4.15.2 Electric Distribution Substation, Replace Transformer (MWC 54)....	545
4.15.3 Electric Distribution Substation, Safety and Security (MWC 58)	547
4.16 Distribution System Automation And Protection (DSAP)	549
4.16.1 PG&E’s Expense And Capital Forecast Is Uncontested	549
4.17 Electric Distribution Capacity, Engineering and Planning	549
4.17.1 PG&E’s Expense And Capital Forecast	549
4.17.1.1 Electric Distribution Capacity -- Capital (MWCs 06 and 46)	550
4.18 New Business And Work At The Request Of Others.....	554
4.18.1 PG&E’s Expense And Capital Forecast	554
4.18.2 Electric Distribution WRO General (MWC 10).....	555
4.18.3 Electric Distribution Customer Connects (MWC 16)	555
4.18.3.1 Residential Connects.....	556

TABLE OF CONTENTS
(continued)

	Page
4.18.3.2 Non-Residential Connects	559
4.18.3.3 Plug-In Electric Vehicles (PEV).....	560
4.18.3.4 Transformer Purchases.....	561
4.19 Rule 20A	561
4.20 Electric Distribution Data Management And Technology	564
4.20.1 PG&E’s Expense And Capital Forecast	564
4.20.2 Electric Distribution Mapping (MWC GE).....	565
4.20.3 Maintain IT Applications And Infrastructure (MWC JV).....	567
4.21 Integrated Grid Platform And Grid Modernization Plan	568
4.21.1 PG&E’s Expense And Capital Forecast	568
4.21.2 Emerging Technology (MWC AT)	569
4.21.3 Electric Distribution Operations, Advanced Distribution Management System (ADMS) And Distributed Energy Resources Management System (DERMS) (MWC 63).....	570
4.22 Electric Distribution Support	576
4.22.1 PG&E’s Expense And Capital Forecast	576
4.22.2 Miscellaneous Expense (MWC AB)	576
4.23 Community Rebuild Program	578
4.23.1 PG&E’s Expense And Capital Forecast	579
4.23.2 Summary Of Intervenor’s Recommendations	580
4.23.3 Community Rebuild Costs Forecast In The GRC Should Not Be Subject To CEMA	581
4.23.4 PG&E Proposed Treatment Of Community Rebuild Costs Is Appropriate.....	584
4.24 Electric Distribution Ratemaking	585
4.24.1 Wildfire Mitigation Balancing Account (WMBA)	585
4.24.2 Vegetation Management Balancing Account (VMBA)	589
4.24.3 Additional Balancing Accounts.....	591
5. ENERGY SUPPLY (EXHIBIT PG&E-05).....	592
5.1 Forecast	592
5.2 Energy Supply Risk Management	596

TABLE OF CONTENTS (continued)

	Page
5.3 Nuclear Operations Costs	596
5.3.1 Nuclear Operations Expense	596
5.3.2 Nuclear Operations Capital	598
5.3.3 Nuclear Ratemaking Proposals.....	599
5.4 Hydro Operations Costs.....	600
5.4.1 Hydro Expense	600
5.4.1.1 Operational Support (MWC OS)	602
5.4.1.2 Balancing Account Process (MWC IG).....	604
5.4.2 Hydro Capital Expenditures	605
5.4.2.1 Cal Advocates Proposal To Use 2021 Recorded Data.....	608
5.4.2.2 Install/Replace Infrastructure (MWC 2P).....	608
5.4.2.3 Forecasts For FERC Projects With Pending Licenses (MWC 3H).....	609
5.4.3 Potter Valley Transformer Project.....	611
5.5 Natural Gas and Solar Generation Operations Costs.....	612
5.5.1 Natural Gas And Solar O&M Expense	613
5.5.2 Natural Gas And Solar Capital Expenditures.....	613
5.5.3 Gateway Evaporative Cooling Project	615
5.5.4 Long Term Service Agreement (MWC KL)	616
5.6 Energy Procurement And Administration Costs.....	617
5.6.1 Energy Procurement And Administration Expense Costs.....	617
5.6.1.1 Acquire and Manage Gas Supply (MWC CV)	618
5.7 Energy Supply Technology Programs	619
5.8 Energy Supply Ratemaking	620
5.8.1 Hydro Decommissioning Accrual	620
5.8.2 Hydro Licensing Balancing Account	622
5.8.3 Helms Capacity Memorandum Account	623
5.8.4 Utility Owned Generation Vintaging	624
5.8.4.1 JCCA Proposals Unlawfully Shift Costs To Bundled Customers	625

TABLE OF CONTENTS

(continued)

	Page
5.8.4.2 There Is No Need to Adopt the JCCA Proposed Framework	628
5.8.4.3 PG&E's Hydroelectric Assets Should Remain In The Legacy UOG Vintage	629
5.8.5 Diablo Canyon Retirement Balancing Account	631
6. CUSTOMER AND COMMUNICATIONS (EXHIBIT PG&E-06)	632
6.1 Forecast	632
6.2 Regional Vice Presidents	633
6.3 Customer Engagement	635
6.3.1 Non-Tariffed Products And Services	636
6.3.2 The Electric Vehicle Infrastructure Forecast Is Just And Reasonable.....	638
6.3.3 The Internal Fleet Program Forecast Is Reasonable And Should Be Approved.....	639
6.4 Pricing Products and Income Qualified Programs.....	640
6.5 Contact Centers, Customer Technology, and Digital Strategy	640
6.6 Customer Service Offices	641
6.7 Billing, Revenue And Credit.....	643
6.8 Metering Services and Engineering.....	644
6.9 Compliance and Regulatory Strategy	645
6.10 Gas AMI Module Replacement	646
6.10.1 PG&E's Proactive Replacement Project Is The Least Cost Option To Replace Critical AMI Equipment	648
6.10.2 PG&E Has Prudently Managed Its Gas AMI Program Since Inception	649
6.10.3 If Proactive Replacement Is Denied, Corrective Maintenance Costs Will Increase.....	654
6.10.4 PG&E Should Earn A Full Rate Of Return On Early Module Retirements.....	656
6.11 Customer Care Technology Projects	658
6.11.1 PG&E's Forecast For The Billing System Upgrade Is Supported Given The Current Project Stage.....	660

TABLE OF CONTENTS

(continued)

	Page
6.11.2 Projects Related To The Current Billing System Are Not Embedded In Rates.....	661
6.11.3 PG&E Has Properly Capitalized Cloud Computing Costs.....	662
6.11.4 The Billing System Upgrade Is Essential To Responsive Rate Change.....	663
6.12 Communications	666
6.13 Customer and Communications Ratemaking.....	666
7. SHARED SERVICES AND INFORMATION TECHNOLOGY (EXHIBIT PG&E-07)	667
7.1 Forecast.....	667
7.2 Enterprise Health And Safety/Occupational Health	668
7.2.1 PG&E's Expense And Capital Forecast.....	669
7.2.2 Summary Of Parties' Positions	670
7.2.3 Transitional Light-Duty Payroll	671
7.2.4 Voluntary Plan And Third Party Disability Management (LTD/STD Pay As You Go).....	672
7.2.5 Wellness Programs	674
7.2.6 Employee Assistance Program	675
7.2.7 Mental Health Services.....	676
7.3 Transportation And Aviation Services.....	677
7.3.1 Expense And Capital Forecasts	677
7.3.2 Transportation Services Expense (MWC AB)	678
7.3.3 Vehicle Expense (MWC AB).....	680
7.3.3.1 Overhead Credit (MWC ZC)	681
7.3.4 Fleet/Automotive Equipment (MWC 04).....	682
7.4 Materials	685
7.4.1 Miscellaneous Expense (MWC AB)	685
7.4.2 Procure Materials and Services (MWC JL).....	686
7.5 Sourcing.....	687
7.6 Real Estate	687
7.6.1 Manage Properties And Buildings (MWC EP)	688

TABLE OF CONTENTS

(continued)

	Page
7.6.1.1 Conference Centers Program	689
7.6.1.2 Facilities Management Program	691
7.6.2 Line Of Business Wildfire Mitigation Support (MWC IG)	692
7.6.3 Implement Real Estate Strategy (MWC JH)	693
7.6.4 Building Services Overhead Credit (MWC ZC)	694
7.6.5 Implement Real Estate Strategy (MWC 23).....	695
7.6.5.1 SFGO/Oakland Lakeside Project.....	696
7.6.5.2 Aviation Operation Center.....	698
7.6.5.3 Service Center Security Fencing Program.....	699
7.7 Land and Environmental Management	701
7.8 Enterprise Records And Information Management And Enterprise Data Management.....	702
7.8.1 EDM Program (MWC AB)	703
7.9 Information Technology	704
7.9.1 Baseline O&M Non-Labor (MWC JV).....	707
7.9.2 Technology Investments: Solution Delivery And Operations (MWC JV)	708
7.9.3 Technology Investments: Field Work Management, Data Enablement And Enterprise Resource Management (MWC JV).....	709
7.9.4 Technology Investments: Core Network Infrastructure And Operations (MWC 2F).....	710
7.9.5 Technology Investments Portfolio Capital (MWC 2F).....	711
7.10 Cyber and Corporate Security.....	712
7.11 Geosciences.....	713
7.12 Enterprise Risk Management.....	714
8. HUMAN RESOURCES (EXHIBIT PG&E-08).....	717
8.1 HR Solutions and Services	720
8.1.1 Department Costs	721
8.1.2 Information Technology	723
8.2 HR Service Delivery and Inclusion	724
8.2.1 Department Costs	724

TABLE OF CONTENTS (continued)

	Page
8.2.2 Companywide Expenses (Workforce Transition; Tuition Refund).....	727
8.2.2.1 Workforce Transition.....	727
8.2.2.2 Tuition Refund.....	730
8.3 Compensation: Short Term Incentive Plan (STIP), Non-Qualified Retirement, Rewards and Recognition and Labor Escalation	731
8.3.1 Short Term Incentive Plan – Utility/Affiliates	732
8.3.1.1 Summary Of The Forecast And Parties’ Recommendations.....	734
8.3.1.2 The Commission Should Reject Cal Advocates’ And TURN’s Recommendations To Reduce STIP Funding.....	735
8.3.2 Non-Qualified Retirement.....	748
8.3.3 Rewards And Recognition (R&R): The Commission Should Not Adopt Cal Advocates Recommendation For PG&E’s R&R Program.	750
8.3.4 Labor Escalation.....	753
8.4 Employee Benefits.....	753
8.4.1 Department Costs	754
8.4.2 Companywide Expenses (Benefit Plans).....	755
8.4.2.1 Summary of PG&E’s Benefit Plans.....	755
8.4.2.2 PG&E’s Total Compensation Study Reflects The Value Of Employee Benefits.....	757
8.4.2.3 Employee Benefits Are A Key Component Of Labor Negotiations	757
8.4.2.4 Benefits Forecast.....	758
8.4.2.5 Cal Advocates’ Significant Proposed Reductions To The Medical Plans Forecast Should Not be Adopted.	763
8.5 PG&E Academy.....	765
8.5.1 Department Costs	767
8.5.1.1 Cal Advocates’ Recommended Reductions To The PG&E Academy Forecast Should Not Be Adopted	767
8.5.1.2 The Commission Should Adopt The PG&E/ESC Memorandum of Understanding (MOU) Resolving PG&E Academy Issues.....	768

TABLE OF CONTENTS
(continued)

	Page
8.6 Total Compensation Study.....	770
9. ADMINISTRATIVE AND GENERAL EXPENSES (EXHIBIT PG&E-09).....	772
9.1 Summary of Settlements And Stipulations	772
9.2 Forecast.....	775
9.2.1 Summary Of The Forecast.....	775
9.2.2 Updated Forecast Reflecting Settlements And Stipulations.....	778
9.3 Finance Organization Costs	778
9.3.1 Department Costs	779
9.3.2 Companywide Expenses (Bank Fees)	779
9.3.3 Technology Projects	780
9.4 Risk, Audit And Insurance.....	781
9.4.1 Department Costs	781
9.4.1.1 Internal Audit Staffing	782
9.4.1.2 Privileged Internal Audit Reports	782
9.4.2 Insurance.....	783
9.4.2.1 Property Insurance Forecast.....	784
9.4.2.2 General Liability Insurance.....	787
9.4.2.3 Directors And Officers Liability Insurance	792
9.4.2.4 Other Liability Insurance	793
9.4.2.5 PG&E Corporation Allocation.....	793
9.4.2.6 Risk Transfer Balancing Account.....	794
9.4.3 Information Technology	796
9.5 Compliance And Ethics	797
9.5.1 Department Costs	798
9.5.2 Technology Projects	798
9.6 Regulatory Affairs	799
9.6.1 Department Costs	799
9.6.2 Technology Projects	800
9.7 Law Department.....	801
9.7.1 Department Costs	801

TABLE OF CONTENTS

(continued)

	Page
9.7.2 Companywide Expense (Settlements, Judgements And Claims).....	801
9.7.3 Technology Projects	803
9.8 PG&E Corporation, PG&E Executive Offices And Corporate Secretary	803
9.8.1 Department Costs	804
9.8.2 Companywide Expenses (Director Fees And Expenses)	804
9.9 Corporate Affairs Costs	805
9.10 Administrative And General Ratemaking Adjustments	806
10. RESULTS OF OPERATIONS (EXHIBIT PG&E-10).....	808
10.1 Depreciation.....	808
10.2 Income And Property Taxes	808
10.2.1 PG&E's Opening Testimony.....	808
10.2.2 Update Testimony – Tax Updates (PG&E-33, Chapter 3).....	809
10.2.2.1 Adjustments to Comply with the Internal Revenue Code Normalization Rules.....	810
10.2.2.2 Inflation Reduction Act of 2022 – Corporate Alternative Minimum Tax	811
10.2.2.3 Gas Transmission Method Change	811
10.3 Working Cash	812
10.3.1 Customer Deposits.....	814
10.3.2 Revenue Lag And Bank Lag	815
10.3.2.1 Bank Lag.....	816
10.3.2.2 Revenue Lag	817
10.3.3 Goods And Services Expense Lag	817
10.3.4 Federal And State Income Tax Lags	819
10.4 Electric And Gas Distribution, Electric Generation, Gas Transmission And Storage Rate Base	823
10.4.1 Community Rebuild Program Costs Are Not Limited to Recovery Through the Catastrophic Events Memorandum Account	824
10.4.2 Costs For Capital Work That Is Used and Useful Is Properly Included As Utility Plant In A GRC.....	825
10.5 Other Operating Revenues.....	828
10.6 Calculation of the Revenue Requirement	828

TABLE OF CONTENTS
(continued)

	Page
10.7 Payroll & Other Taxes	829
10.8 Administrative And General Allocation Factors And Franchise Fee Factor.....	830
11. POST TEST-YEAR RATEMAKING (PTYR) (EXHIBIT PG&E-11).....	831
11.1 Post Test-Year Rate Mechanism.....	831
11.1.1 PG&E’s Post Test Year Proposal	834
11.1.2 PG&E’s Cost-Based Proposal Is the Only Mechanism Sufficient To Cover PG&E’s Costs	835
11.1.3 Summary Of Parties’ PTYR Proposals	837
11.1.4 Cal Advocates Proposals Should Be Rejected	839
11.1.4.1 The Commission Should Not Adopt Cal Advocates’ Primary Recommendation For 3 Percent Single-Index Escalation Based On The Consumer Price Index Because It Would Significantly Underfund The Utility During The Attrition Years.....	839
11.1.4.2 Use Of A Single Index Is Flawed Whether Based On A CPI Or Results In Other GRCs	842
11.1.4.3 The Commission Should Not Adopt Cal Advocates’ Recommendations That Provide No PTYR Adjustments For Specific PG&E Programs.....	845
11.1.4.4 The Commission Should Not Adopt Cal Advocates’ Alternative Recommendation For 2 Percent O&M Cost Reductions In The PTYs.....	846
11.1.5 TURN’s Proposals Should Be Rejected	847
11.1.5.1 The Commission Should Not Adopt TURN’s Recommendations For A PTYR Mechanism That Incorporates Escalation Based On CPI And A 7-Year Average Methodology To Forecast Capital Additions	847
11.1.5.2 The Commission Should Not Adopt TURN’s Primary Proposal To Escalate Capital Additions Based On A 7- Year Average.	848
11.1.5.3 Using a 7-year Average Would Significantly Underfund PG&E’s Operations And Fails To Account For The Significant Capital Investment PG&E Forecasts For The 2023 GRC Period.....	848
11.1.5.4 Using a 7-year Average Is Not Consistent With The Majority Of Recent Precedent On The Issue.	851

TABLE OF CONTENTS
(continued)

	Page
11.1.5.5 The Commission Should Not Adopt TURN's Alternative Recommendation To Escalate Capital Costs By CPI Plus 50 Basis Points	853
11.2 Z-Factor Memorandum Account	854
11.2.1 Z-Factor Adjustments Should Apply To The Test Year	855
11.2.2 The Commission Should Permit PG&E To Seek Recovery Of Z- Factor Costs Via Advice Letter Filing.....	855
12. GENERAL REPORT (EXHIBIT PG&E-12).....	856
12.1 Escalation Rates	856
12.2 Compliance With Prior Commission Decisions	857
12.3 Balancing Accounts And Memorandum Accounts.....	859
12.3.1 Catastrophic Event Straight-Time Labor Balancing Account (CESTLBA).....	864
12.3.2 Z-Factor Memorandum Account.....	864
12.3.3 Other Balancing Or Memorandum Accounts.....	865
12.3.3.1 General Rate Case Memorandum Accounts And Gas Transmission And Storage Memorandum Account.....	865
12.3.3.2 Additional Disputed And Undisputed Balancing And Memorandum Accounts.....	866
13. UPDATE TESTIMONY (EXHIBIT PG&E-33).....	867
13.1 PG&E's Updated Escalation Rates Are Reasonable And Should Be Approved.....	867
13.2 PG&E's Update To Escalation Factors Using IHS Markit Data Is Consistent With Decades Of Commission Precedent.....	868
13.2.1 The Updated Escalation Factors Must Be Adopted In Their Entirety	871
13.3 PG&E's Update For Tax Changes Are Reasonable And Should Be Approved.....	874
14. MEMORANDUMS OF UNDERSTANDING.....	875
14.1 Small Business Utility Advocates.....	875
14.2 Center For Accessible Technology	876
14.3 National Diversity Coalition	877
14.4 Engineers And Scientists of California Local 20.....	879

TABLE OF CONTENTS
(continued)

	Page
15. OTHER ISSUES	880
16. CONCLUSION.....	880
17. GLOSSARY	883
17.1 Acronyms and Abbreviations	883
17.2 Major Work Categories and Maintenance Activity Type Codes.....	908

TABLE OF AUTHORITIES

Page(s)

FEDERAL AUTHORITIES

Statutes and Regulations

49 CFR § 192	104, 128
49 CFR § 192.937(c).....	134
49 CFR § 192.741(a)(c)	316
86 Fed. Reg. 31002	115
16 U.S.C. § 808(a)(1).....	630

Case Law

<i>Arlington v. FCC</i> , (2013) 569 U.S.290	71
<i>Missouri ex rel. Southwestern Bell Tel. Co. v. Public Service Com.</i> , (1923) 262 U.S. 276.....	15, 76
<i>Util. Air Regul. Grp. v. EPA</i> , (2014) 573 U.S. 302	71

CALIFORNIA AUTHORITIES

Statutes and Regulations

Assembly Bill No. 1054 (2019-2020 Reg. Sess.)	<i>passim</i>
Assembly Bill No. 3232 (2017-2018 Reg. Sess.)	663
Consolidated Appropriations Act, 2021	194
Govt. Code, § 15475.1	48
Public Utilities Code § 365.2	627, 629
Public Utilities Code § 366.2	626, 629, 630
Public Utilities Code § 366.2(a)(4).....	628
Public Utilities Code § 366.2(d)(1).....	626
Public Utilities Code § 366.3	627, 629, 630
Public Utilities Code § 451	2, 11
Public Utilities Code § 454(a).....	11
Public Utilities Code § 591	60
Public Utilities Code § 706	646
Public Utilities Code § 854.2(a)(6).....	14, 67
Public Utilities Code § 958(c)(3).....	130
Public Utilities Code § 961	106
Public Utilities Code § 961(c).....	49
Public Utilities Code § 961(d)(5).....	316

TABLE OF AUTHORITES

(continued)

Page

Public Utilities Code § 961(d)(9).....	49
Public Utilities Code § 963	106
Public Utilities Code § 963(b)(3).....	32
Public Utilities Code § 1757(a)(3), (4)	13
Public Utilities Code § 3280(f).....	790
Public Utilities Code § 3280(n)(2).....	70
Public Utilities Code § 8386	42
Public Utilities Code § 8386(a).....	32, 48, 469
Public Utilities Code § 8386(c)(14).....	49
Public Utilities Code § 8386.1	2
Public Utilities Code § 8389(g)	2
Public Utilities Code § 8386.3(e).....	70,72
Public Utilities Code § 8389(e)(6)(A)(i)(I).....	738
Senate Bill No. 100 (2017-2018 Reg Sess.)	665
Senate Bill No. 221 (2021-2022 Reg. Sess.)	678
Senate Bill No. 884 (2021-2022 Reg. Sess.) § 2 (Pub. Util. Code § 8388.5(e))	72
Senate Bill No. 884 (2021-2022 Reg. Sess.) § 2 (Pub. Util. Code § 8388.5(j))	71

Case Law

<i>Assembly v. Public Util. Com.</i> , (1995) 12 Cal. 4th 87	71
<i>BNSF Railway Co. v. Pub. Util. Com.</i> , (2013) 218 Cal. App. 4th 778	71
<i>City and County of San Francisco v. Public Utilities Com.</i> (1971) 6 Cal.3d 119	72
<i>Morris v. Williams</i> , (1967) 67 Cal. 2d 733, 748	71
<i>Southern Cal. Edison Co. v. Public Utilities Com.</i> , (1978) 20 Cal.3d 813.....	15, 76
<i>Southern Cal. Gas Co. v. Public Utilities Com.</i> (1979) 23 Cal. 3d 470	72
<i>Southern Cal. Gas Co. v. Public Util. Com.</i> , (1979) 24 Cal. 3d 653	71

California Public Utilities Commission

Decisions

D.82-12-055, 1982 Cal PUC LEXIS 1209, 10 CPUC 2d 155.....	871
D.83-12-068, 14 CPUC2d 15.....	57
D.84-05-036, 1984 Cal. PUC LEXIS 1325, 15 CPUC2d 42	822
D.85-03-042, 17 CPUC2d 246.....	16
D.87-12-067, 27 CPUC 2d 1.....	13
D.89-01-040, 1989 Cal. PUC LEXIS 37, 30 CPUC 2d 576.....	78, 869
D.94-06-033, 1994 Cal. PUC LEXIS 428, 55 CPUC2d 158.....	65

TABLE OF AUTHORITIES
(continued)

	Page
D.94-12-068, 16 CPUC2d 721.....	57
D.95-12-055, 1995 Cal. PUC LEXIS 965, 63 CPUC2d 570.....	773
D.00-02-046.....	774
D.03-05-076.....	861
D.04-07-022.....	74, 75, 739, 846, 853
D.04-12-047.....	69
D.05-12-043.....	69
D.06-05-016.....	834, 853
D.06-07-027.....	652, 655
D.07-07-004.....	<i>passim</i>
D.07-07-041.....	584, 861
D.07-12-049.....	69
D.08-01-022.....	13
D.08-12-058.....	13
D.11-05-018.....	16, 55, 57, 60, 845
D.12-04-024.....	430
D.12-11-051.....	72, 73, 853
D.12-12-034.....	69
D.13-05-010.....	74, 573, 739, 746
D.14-06-047.....	12
D.14-08-032.....	<i>passim</i>
D.14-12-078.....	859
D.15-03-049.....	13
D.15-04-024.....	860
D.15-11-021.....	12, 75, 853
D.16-05-024.....	13
D.16-06-054.....	178, 845
D.16-06-056.....	<i>passim</i>
D.16-09-044.....	629
D.16-12-010.....	860
D.17-05-013.....	61, 450, 511, 845
D.17-06-015.....	300
D.18-01-022.....	631
D.18-03-023.....	572
D.18-06-029.....	65, 861, 864
D.18-07-006.....	13
D.18-10-019.....	626, 630
D.18-10-020.....	13
D.18-12-009.....	13
D.18-12-014.....	26, 27, 32, 33, 44, 45

TABLE OF AUTHORITES

(continued)

Page

D.19-04-020	60, 611
D.19-05-020	12, 14 73, 853
D.19-09-025	<i>passim</i>
D.19-09-026	695
D.19-09-051	<i>passim</i>
D.19-12-056	69
D.20-01-002	14, 78, 611
D.20-02-036	267
D.20-05-019	584, 585
D.20-05-037	130, 135
D.20-05-042	695
D.20-05-053	419, 635, 636, 740, 872
D.20-06-003	816
D.20-07-032	9
D.20-07-038	12, 13, 675, 731
D.20-12-005	<i>passim</i>
D.21-05-003	833
D.21-07-017	77
D.21-08-024	584
D.21-08-027	699
D.21-08-036	<i>passim</i>
D.21-11-009	130, 135, 136, 137
D.22-06-028	636, 867
D.22-06-032	652
D.22-08-023	10
D.22-09-026	<i>passim</i>
D.22-10-002	60, 61

Rulemakings

<i>Order Instituting Rulemaking to Consider Alternative-Fueled Vehicle Tariffs, Infrastructure and Policies to Support California’s Greenhouse Gas Emissions Reduction Goals, R.09-08-009 (Aug. 24, 2009)</i>	640
<i>Order Instituting Rulemaking to Continue the Development of Rates and Infrastructure for Vehicle Electrification, R.18-12-006 (Dec. 19, 2018)</i>	640
<i>Order Instituting Rulemaking Regarding Building Decarbonization, R.19-01-011 (Jan. 31, 2019)</i>	347
<i>Order Instituting Rulemaking to Establish Policies, Processes, and Rules to Ensure Safe and Reliable Gas Systems in California and perform Long-Term Gas System Planning, R.20-01-007 (Jan. 27, 2020)</i>	229

TABLE OF AUTHORITIES
(continued)

Page

<i>Order Instituting Rulemaking to Further Develop a Risk Based Decision Making Framework for Electric and Gas Utilities, R.20-07-013 (July 16, 2020)</i>	62, 90

Rulings

<i>Assigned Commissioner’s Scoping Memo and Ruling (Oct. 1, 2021)</i>	76
<i>E-Mail Ruling Addressing Pending Motions & Request to Modify Schedule and Adopting Revised Schedule (Apr. 12, 2022)</i>	413
<i>A.20-06-012, ALJ Lirag’s E-Mail Ruling Denying Joint Motion by Cal Advocates and FEITA (June 3, 2021)</i>	374
<i>R.18-07-006, Assigned Commissioner’s Ruling Amending Ruling of May 20, 2022 and Further Updating Proceeding Schedule for Phase 3 of Proceeding (June 9, 2022)</i>	77
<i>R.20-07-013, Assigned Commissioner’s Ruling Issuing Phase II Roadmap for Comment (Feb. 16, 2022)</i>	28
<i>R.20-07-013, Assigned Commissioner’s Scoping Memo and Ruling (Nov. 2, 2020)</i>	28
<i>R.21-06-017, Assigned Commissioner’s Scoping Memo and Ruling (Nov. 15, 2021)</i>	572

Resolutions

<i>Resolution E 4963 (Dec. 13, 2018)</i>	760, 806
<i>Resolution G-3538 (Oct. 11, 2018)</i>	359

Advice Letters

<i>AL 4579-G/6513-E</i>	812

Tariffs

<i>Gas Rule 2</i>	344
<i>Gas Rule 15</i>	344
<i>Gas Rule 16</i>	344

Rules of Practice and Procedure

<i>Rule 12.5</i>	845

General Orders

<i>General Order 58-A</i>	316

Pacific Gas and Electric Company | Opening Brief

-xxxii-

TABLE OF AUTHORITIES
(continued)

Page

Miscellaneous

Governor’s Executive Order No. N-79-20.....640

Governor Newsom’s Strike Force Progress Report on Catastrophic Wildfires,
Climate Change and Our Energy Future (June 21, 2019).....64

PG&E’s Electric Preliminary Statement, Part G (Sept. 3, 2022).....582

PG&E’s Gas Preliminary Statement, Part DP 176

State of California Middle-Mile Broadband Initiative (June 2022).....400

APPENDIX LIST

- Appendix A Undisputed Forecast Programs with No Recommended Test Year 2023 Disallowance
- Appendix B Uncontested Balancing Accounts, Memorandum Accounts and Other Non-Forecast Issues
- Appendix C Contested Balancing Accounts and Memorandum Accounts
- Appendix D 2023 GRC RO Model Presentations | PG&E's Results of Operations Model
- Appendix E Stipulation of TURN and PG&E on Energy Supply Issues
- Appendix F Stipulation of Cal Advocates, TURN and PG&E on Enterprise Data Management and Information Technology Forecasts in A.21-06-021
- Appendix G Stipulation of TURN, Cal Advocates and PG&E on Administrative And General Issues
- Appendix H Test-Year 2023 Forecast Summaries

1. INTRODUCTION AND SUMMARY OF RECOMMENDATIONS

PG&E's responsibilities go far beyond our core mission of providing safe, reliable, affordable, and clean energy to sixteen million people in Northern and Central California. We are also responsible to build a better future for everyone whose lives we touch. In this 2023 General Rate Case (GRC), we seek to deliver on our core mission and build that better future. We seek funding that will allow us to safely and reliably deliver for our hometowns, reduce the environmental impact of our operations, drive clean energy technologies, and, most importantly, protect our communities and make them more resilient to our ever-changing climate. We must tackle the challenges of climate change for the prosperity of the state, our customers, and the generations to come. Our proposals in this GRC seek to meet these challenges.

1.1 Policy Overview: PG&E Must Have Adequate Funding To Provide Safe And Reliable Service

PG&E's most important responsibility is to provide safe and reliable service to our customers we are privileged to serve.¹ In this GRC, we are proposing plans necessary to provide safe and reliable service in this world of changing climate-driven risks. Approximately **86 percent** of the requested increase over 2022 adopted rates is to mitigate risk in our gas and electric operations² and deliver that level of safety that our customers expect and deserve.

Putting safety first is the right thing to do. Our plans include mitigating the risk of catastrophic wildfires, improving public and workforce safety, and building a culture of strong performance. These plans support a bright and prosperous future for California.

While PG&E is committed to keeping customer costs as low as reasonably possible, we understand that the magnitude of this GRC request, if approved, could be difficult for some customers. Our proposals were not taken lightly. These investments may be substantial, though

¹ PG&E-01, p. 1-1, lines 6-7.

² PG&E-14, p. 3-24, lines 8-10; TURN-108 (PG&E response to TURN 215-2 and attachments). This amount was calculated before the September 6, 2022, Update Testimony (Update Testimony) was submitted and does not reflect the inflation-adjusted amounts.

they must be considered on their merits. One should not reject these plans now as too expensive only to have to incur higher costs later. The consequences of inaction are high. Indeed, the risks of not undertaking this important work must be balanced against the utility’s mandate to provide “such adequate, efficient, just, and reasonable service instrumentalities, equipment and facilities, ... as are necessary to promote the safety, health, comfort, and convenience of its patrons, employees and the public.”³ As a matter of both safety and economics, we must mitigate the risk of potentially catastrophic events from wildfire to the maximum amount feasible.

The largest driver of the incremental funding request in this GRC, like the 2020 GRC, arises from the need to protect customers from the financial and safety risk of catastrophic wildfires.⁴ As climate change and drought conditions worsen, sufficient funding is needed to address the ever-increasing wildfire risk in PG&E’s service area. While parties propose substantial reductions in funding for that work, and some even argue that the utility’s wildfire mitigation work should not be conducted because wildfires can be ignited by unrelated causes,⁵ we will not turn away from our responsibility to mitigate wildfire risk. PG&E is required by California law to enhance our equipment to reduce wildfire risk consistent with our approved Wildfire Mitigation Plans.⁶ But more importantly, it is the right thing to do to keep our customers and the communities that we serve safe.

We respectfully request the Commission to approve our forecast. A prosperous California cannot exist without financially healthy utilities that provide safe, reliable, and clean energy. A strong PG&E will attract and grow businesses in California. We can and should continue to be an engine for growth and prosperity for California.

³ Pub. Util. Code, § 451.

⁴ See Amended Application, p. 5 (62% of the incremental revenue requirement is for wildfire reduction work, including vegetation management.)

⁵ AARP-01, p. 69, line 16 to p. 70, line 4.

⁶ Pub. Util. Code, §§ 8386.1, 8389(g).

1.2 Summary Of Recommendations

PG&E's key investments in its electric, gas, and generation facilities to improve safety, reliability, and customer service from 2023 to 2026, are summarized below.⁷

1.2.1 Addressing Risks In Our Electric Distribution System

1.2.1.1 Community Wildfire Safety Program

We are resolute in our commitment to prevent catastrophic wildfires and protect the safety of our customers and coworkers. We have intensified our efforts to reduce wildfire risk and developed new ways to accelerate our progress, including: (i) a game-changing program in our High Fire Threat Districts (HFTDs) to underground 10,000 miles of overhead lines; and (ii) re-engineering our electric circuits to detect potential threats instantly and shut off power automatically in our Enhanced Powerlines Safety Settings (EPSS) program.

In this GRC, we are proposing to invest approximately \$11.1 billion in capital and \$3.9 billion in expense between 2023-2026 to reduce the risk of wildfire. Our wildfire mitigation strategy builds on our current progress to reduce risk in our system and increase reliability for our customers. It includes these major activities: (1) System Hardening; (2) EPSS; (3) Situational Awareness and Weather Forecasting Initiatives; (4) Vegetation Management Programs; and (5) Additional Enhanced Automation and Protection. In addition to reducing wildfire risk to keep customers and communities safe, some wildfire mitigation work, such as System Hardening, will improve reliability.

1.2.1.2 Other Electric Distribution Investments

While wildfire is the highest risk associated with our electric distribution equipment, it is not the only risk that we must address. In our Electric Operations forecast, we propose additional investments to reduce system risk throughout our service area; and, as California

⁷ Amounts below do not include the escalation adjustment for inflation PG&E requested in the Update Testimony (PG&E-33).

continues to grow, we are planning for an increase in customer load growth and new connections.

We are also committed to supporting cost-effective achievement of California's greenhouse gas (GHG) emissions reduction goals. Our GRC forecast includes programs associated with distributed energy resources, including an Advanced Distribution Management System and a Distributed Energy Resource Management System. Our forecast also includes electric vehicle (EV) charging infrastructure investments in support of the state's goals for vehicle electrification. Energy storage will play a crucial role in renewable resource integration, helping balance the intermittency of renewable generation and low customer demand during peak generation. Our GRC includes a forecast for one of the largest utility-owned lithium-ion battery energy storage systems installed at the Moss Landing Substation in Monterey County that will improve system reliability by addressing intermittent capacity deficiencies without adding new fossil resources to the grid.

1.2.2 Addressing Risk In Our Gas Operations

We are proposing safety and reliability programs for our extensive gas storage, transmission, and distribution systems. While we have made significant progress on programs designed to enhance public and employee safety and the reliability of our natural gas system, there is still more to do. For gas distribution, our forecasts increase in several public safety programs, including: (1) vintage gas pipeline replacement; (2) corrosion detection and mitigation; (3) leak surveys and repair; and, (4) locate and mark services so customers and workers will know where they can safely dig. For gas transmission, we are proposing to expand our in-line inspection capabilities by performing upgrades to our transmission pipeline, direct assessments where in-line inspections cannot be performed, strength tests, and over pressure protection to increase the safety of our gas transmission assets. We will increase the safety of our gas storage through well reworks and retrofits in compliance with recent regulations issued

by the Pipeline Hazardous Materials and Safety Administration (PHMSA) and the California Department of Conservation, Geologic Energy Management Division (CalGEM).

Many of the gas distribution, transmission, and storage programs are required by state and federal regulations to ensure safe and reliable service to customers. These regulations continue to evolve and add new requirements for our operations.

1.2.3 Building A Safe And Dependable Energy Supply

Our proposals for Power Generation, Energy Policy and Procurement, and the Energy Supply Technology Program seek to enable PG&E to continue to deliver some of the nation's cleanest electricity. More than 90 percent of our electricity came from GHG-free resources in 2021.

Our hydroelectric system is one of the largest investor-owned systems in the nation. We will continue to invest in our generating facilities to keep them operating safely, efficiently, and in full compliance with requirements. We are also investing in our employees to ensure they have the talent, skills and technology needed to analyze, implement, transact, administer, and operate in evolving markets.

Our Energy Supply forecast includes the necessary resources to meet these challenges. We are pleased to have reached agreement with The Utility Reform Network (TURN) on our forecasts for the Energy Supply programs where TURN proposed alternate recommendations. Section 5 of our brief reflects the parties' joint recommendations.

1.2.4 Customer And Communications Proposals To Improve Service, Billing And Communications

PG&E's Customer and Communications organization is central to providing customers with a great customer experience and delivering for our hometowns. Our proposals include projects to improve customer service through our Customer and Community Services teams, Contact Centers, Customer Service Offices, and self-service channels.

Our plans to improve customer service include: (1) our Gas Advanced Metering Infrastructure Modules Replacement project to ensure PG&E continues to provide reliable, timely, and accurate billing to our over 4 million gas customers; (2) our Billing System Upgrade to speed the implementation of new rate programs, and streamline energy bills for customers with complex rates like Net Energy Metering, among other customer benefits; (3) upgrades to pge.com incorporating Web Content Accessibility Guidelines 2.1 to optimize accessibility, while ensuring future changes can be more easily made for our disabled customers; (4) outreach and education, and programs and services, like the Disability Disaster Access and Resources program, that support our vulnerable customers before, during, and after safety events; and (5) support for EV rates and fast-charging infrastructure to meet the needs of the nearly one million EVs that are estimated to be in operation in our service area by the year 2026.

1.2.5 Excess Liability Insurance

PG&E and all California electric utilities are facing increased insurance costs due to wildfire risk. Securing insurance to reduce the financial impact of losses is necessary for PG&E's operations. Due to the high market prices for wildfire insurance, PG&E, the Public Advocates Office at the California Public Utilities Commission (Cal Advocates), and TURN jointly propose to establish a self-insurance fund to avoid purchasing costly insurance on the commercial market. Self-insurance provides a reasonable alternative to purchasing higher-priced policies, which potentially provide lower value for customers. For this reason, PG&E, Cal Advocates and TURN jointly proposed in a settlement motion on October 7, 2022 to set aside funds to establish a self-insurance fund for wildfire liabilities. The parties request a decision by February 2023 on this innovative proposal to avoid a need to purchase wildfire insurance for 2023.⁸

⁸ *Joint Motion of Pacific Gas and Electric Company, The Utility Reform Network and the Public Advocates Office at the California Public Utilities Commission for Expedited Approval and Adoption of the Attached Settlement Agreement on Insurance-Related Issues* (Oct. 7, 2022), p. 3.

1.3 Affordability And Customer Impacts

1.3.1 Affordability Generally

We understand and share our customers' affordability concerns. The proposed expenditures in this GRC represent only a starting point of many more years of work. Thus, these concerns will be with us for a while and the public benefit of these investments needs to be addressed more holistically by the state. If the Commission postpones addressing these needs now, it will be ignoring infrastructure needs and climate-driven wildfire risks that threaten communities in the short term and create a greater affordability issue for the longer term.

Carla Peterman, Executive Vice President of Corporate Affairs, explained:

Affordability is a key issue for PG&E, and so we don't take these rate increases lightly. In terms of affordability to the vulnerable customers... affordability depends on who we're talking about, specifically what [their] individual financial capacity is. And so in terms of our vulnerable customers, we do want to make sure that we are supporting them in enrolling in the right programs and plans to make sure that they can manage their bills as well as possible. I do think it's important...to think about affordability in the context of climate change and the extraordinary risks that we are facing. We are proposing the investments that we need to do our primary job, which is to keep the system safe and reliable, which is something that we owe all of our customers, especially our vulnerable customers.⁹

We acknowledge that the rate increase we are proposing could be difficult for many customers. This is a serious concern. However, any discussion regarding affordability must include a discussion about safety, which must remain the top priority. As the Commission noted in Southern California Edison Company's (SCE) 2021 GRC, while the Commission is mindful of the need to limit rate increases for affordability, the public interest requires the Commission "to ensure that the utility has adequate funding to safely operate and maintain its infrastructure and make necessary investments in safety and reliability."¹⁰

The Commission has grappled with the need to provide rate relief for vulnerable residential customers to assist with utility affordability for decades, whether for energy, water, or

⁹ Transcript (Tr.) Vol. 15, 2791:8 to 2792:3, PG&E/Peterman.

¹⁰ Decision (D.) 21-08-036, p. 26.

other vital utility services. PG&E understands, and agrees, that affordable energy is essential to an adequate quality of life. We share the parties' concern about our most vulnerable residential customers.¹¹ For this reason, we have programs to help these customers afford utility services, including the California Alternate Rates for Energy (CARE), the Federal Emergency Relief Act of 1993 (FERA), and the Energy Savings Assistance (ESA) program.¹² As Dr. Peterman explained:

Approximately 27 percent of PG&E's residential customers are enrolled in either CARE or FERA and 4.6 percent of PG&E's customers are enrolled in the Medical Baseline Program. However, despite these programs, some residential customers are still struggling to pay their utility bills. PG&E offers additional programs to help these customers pay their past due bills. In 2021, we launched the Arrearage Management Plan (AMP) which is a year-long program that allows customers to receive forgiveness of 1/12 of their past due bill after each on-time payment of their current monthly charges (up to \$8,000). We also continue to partner with the California Department of Community Services and Development (CSD) and community-based organizations to help customers access emergency bill relief through the Low-Income Home Energy Assistance Program. PG&E supports exploring solutions to address the impact of bill increases on low-income customers. For example, we have proposed to implement the percentage of Income Payment Plan (PIPP) Pilot, which caps an eligible customer's monthly bill at a fixed percentage of their income.¹³

The problem of increasing infrastructure needs cannot be ignored. While some parties voice support for safety and reliability, their proposed reductions to our forecasts tell a different story. If the Commission determines that infrastructure investment pose significant affordability challenges or disincentives for other policy goals (such as electrification and other programs to reduce GHG), the solution is not to arbitrarily cut GRC funding and jeopardize customer safety, grid reliability, and other crucial public policy objectives. Rather, the solution is to find other

¹¹ PG&E-14, p. 1-1, line 26 to p. 1-2, line 10.

¹² PG&E's ESA program provides qualified customers with home energy efficiency improvements at no cost to assist in reducing energy bills.

¹³ PG&E-14, p. 1-2, lines 11 to 26 (fns. omitted).

funding sources, review disadvantaged community programs and their eligibility, and consider new ratemaking approaches for those costs of providing public benefits.¹⁴

Finally, we are working collaboratively with stakeholders to decrease our costs during these inflationary times while maintaining the safety and reliability that our customers expect and deserve. An example of this is the wildfire insurance settlement discussed in Section 1.2.5 above. This settlement, which builds on the self-insurance proposal that we put forward in this proceeding, will result in an estimated savings to customers of \$307 million in 2023. In addition, as explained in more detail in this Opening Brief, we have reached stipulations with various parties which result in lower forecasts for our Energy Supply organization, Information Technology (IT), and Administrative & General (A&G) expenses, which result in an additional reduction of our forecast. We strongly believe that working with stakeholders to find new and creative solutions, such as the insurance settlement, or to agree on an appropriate forecast for specific areas, will further help address the affordability challenge.

1.3.2 The Affordability Metrics Data, While Informative, Should Not Be Used To Cap The Revenue Requirement Needed To Provide Safe And Reliable Service

The Commission has adopted affordability metrics using a variety of options for methodologies to measure affordability of utility service. While the Commission is reviewing multiple metrics, it has indicated that it is not endeavoring to define:

in absolute terms what makes for affordable essential utility services. Rather, the objective of this decision is to define metrics and methodologies to track relative affordability of essential utility services over time, and to set out a path of future implementation of those metrics and methodologies. The determination of whether any particular measurement of affordability using the metrics adopted by this decision should be used to find that an essential utility service is affordable is left for a future Commission.¹⁵

¹⁴ PG&E-14, p. 1-4, lines 12-17; Tr. Vol. 4, 545:17 to 545:24, PG&E/Peterman; See also TURN-107, PG&E response to TURN 215-1 (listing PG&E's efforts to obtain funding for its work outside of utility bills.).

¹⁵ D.20-07-032, pp. 80-81.

At TURN's request, PG&E produced updated affordability metrics data to account for the escalation rates contained in the Update Testimony.¹⁶ While we anticipate TURN will cite these metrics to argue that the revenue requirement requested in this proceeding should be reduced, the Commission should be cautious about overreliance on such data at this time. As the Commission recently remarked,

There will be a learning curve to using the affordability metrics and the tools adopted in this decision, and this decision further acknowledges that the calculation of cumulative rate impacts across proceedings requires access to cost and rate data that is just now in the process of being collected. Therefore, this decision authorizes Commission staff to begin the process of incorporating into future annual Affordability Reports the forecast changes in the cumulative impact of multiple pending proceedings, beginning with the electric sector, with the hope that some initial cumulative impact results will be made available prior to the next round of party feedback on the implementation of the affordability metrics, as established by this decision.¹⁷

The new metrics will be subject to a “multi-year period of assessment” to further enhance “the validity of the metrics and their use.”¹⁸

Additionally, while the affordability metrics adopted and defined by D.20-07-032 present one set of measurements that can be used to assess customer affordability, they are not the only method. In recognition of the various interpretations regarding how to define these metrics, the Commission has explained that its:

[A]doption of affordability metrics and approval of inputs and methodologies underlying the metrics does not preclude stakeholders from generating variations on or alternatives to the adopted metrics in Commission proceedings.¹⁹

In PG&E's February 2022 Affordability Metric Report and September 2022 data request response, PG&E supplemented the affordability metrics established by D.20-07-032 by calculating the Hours at Minimum Wage metric and Affordability Ratio metric for the 20th

¹⁶ See TURN-615.

¹⁷ D.22-08-023, p. 55.

¹⁸ D.22-08-023, p. 71.

¹⁹ D.22-08-023, p. 77, Finding of Fact (FOF) 17.

percentile income level using an essential usage bill that reflects rates attributed to customers enrolled in the CARE program, in addition to the calculations using non-CARE rates. Using CARE rates reduces the affordability metrics and recognizes that many customers earning minimum wage or within the 20th percentile of income based on their geographical region are eligible for the CARE program. CARE is one example of a program that is targeted specifically towards low-income customers, however, there are other programs in place or under development which, if considered, would present an alternate view of the affordability metrics. For example, the Energy Savings Assistance Program helps customers install energy efficiency upgrades to reduce energy bills. In addition, D.21-10-012 adopted the Percentage of Income Payment Plan (PIPP) pilot, which once implemented will place a cap on monthly gas and electric bills for eligible customers based on a percentage of income.²⁰ While it is not yet implemented, taking this program into consideration would lower the affordability metrics for eligible customers. Low-income programs such as these are in place and under development to specifically address affordability concerns for PG&E's most vulnerable customers. Placing a cap on PG&E's revenue requirement in this proceeding to lower the impact to the affordability metrics would sacrifice critical safety and reliability investments that benefit all PG&E's customers.

1.4 Legal And Ratemaking Principles

1.4.1 Burden And Standard of Proof

All rates and charges collected by a public utility must be “just and reasonable.”²¹ A public utility may not change any rate “except upon a showing before the commission and a finding by the commission that the new rate is justified.”²² “The Commission requires that the

²⁰ Under this pilot, customers in the lowest income level would receive an electric bill capped at a maximum of \$29 and a gas bill capped at a maximum of \$9.

²¹ Pub. Util. Code, § 451.

²² Pub. Util. Code, § 454(a).

public utility demonstrate with admissible evidence that the costs which it seeks to include in revenue requirement are reasonable and prudent. The Commission is charged with the responsibility of ensuring that all rates demanded or received by a public utility are just and reasonable.”²³

“Costs are just and reasonable when they ‘have been prudently incurred by competent management exercising the best practices of the era, and using well-trained, well-informed and conscientious employees and contractors who are performing their jobs properly.’”²⁴ In considering whether proposed costs are “just and reasonable,” the Commission will often consider the prudence of the utility’s actions. A utility’s “forecast costs are not unreasonable and subject to ratemaking disallowance simply because its management delayed or deferred work.”²⁵ Rather, “disallowances are warranted where costs have been incurred resulting from clear and identifiable utility failures and errors.”²⁶ Thus, “a disallowance is warranted when the forecast work is necessary because: (1) the utility had not originally performed the work properly; (2) the utility had failed to comply with regulatory requirements that it was previously funded to satisfy; or (3) the costs to be incurred are due to clear and identifiable failures and errors.”²⁷

In GRCs, the utilities have the “ultimate burden to prove the reasonableness of the relief they seek and the costs they seek to recover.”²⁸ The standard of proof PG&E must meet is a preponderance of evidence.²⁹ “Preponderance of the evidence is defined in terms of probability

²³ D.16-06-056, p. 21.

²⁴ D.16-06-056, p. 22 (citing D.14-06-007, p. 31).

²⁵ D.16-06-056, p. 22.

²⁶ D.16-06-056, p. 22.

²⁷ D.16-06-056, pp. 22-23; also see D.19-09-025, p. 5.

²⁸ D.20-07-038, p. 3.

²⁹ D.19-05-020, p. 7 (citing D.15-11-021, pp. 8-9).

of truth, e.g., such evidence as, when weighed with that opposed to it, has more convincing force and the greater probability of truth.”³⁰ In short, “PG&E must present more evidence that supports the requested result than would support an alternative outcome.”³¹ As discussed in this Opening Brief, for each of the programs and forecasts, PG&E has amply met its burden.

Parties opposing PG&E’s programs or forecasts have the burden of going forward to produce evidence to support their own position and raise reasonable doubt as to the utility’s request.³² “[W]here other parties propose a result different from that asserted by the utility, they have the burden of going forward to produce evidence, distinct from the ultimate burden of proof.”³³ This “burden of going forward to produce evidence relates to raising a reasonable doubt as to the utility’s position and presenting evidence explaining the counterpoint position.”³⁴ Mere assertions, in other words, are not enough to warrant a different result than the one proposed by a utility that has made a *prima facie* showing of reasonableness; an intervenor must put forward evidence to support an alternative outcome. Thus, to the extent PG&E has met its burden of proof and its proposals are uncontested or the party opposing a forecast does not submit evidence raising a reasonable doubt as to the utility’s position,³⁵ PG&E’s forecasts should be approved.

³⁰ D.18-10-020, p. 38 (citing Witkin, Cal. Evidence (4th ed., Vol. 1, p. 184); *see also* D.16-06-056, p. 23 (citing D.08-12-058, p. 19).

³¹ D.16-06-056, p. 23.

³² D.20-07-038, pp. 3-4; See also D.18-12-009, p. 12; D.18-07-006, p. 15; D.16-05-024, p. 10; and D.15-03-049 p. 6. (Each decision cites D.87-12-067, 27 CPUC2d 1, 22.).

³³ D.08-01-022, p. 4; see also D.20-07-038, pp. 3-4 (TURN must meet its “burden of going forward” to prevail on arguments opposing the utilities’ request).

³⁴ D.08-01-022, p. 4.

³⁵ Commission decisions must be based on substantial evidence. Pub. Util. Code, § 1757(a)(3), (4).

1.4.2 Ratemaking

1.4.2.1 Legal Issues

1.4.2.1.1 The Regulatory Compact

The “regulatory compact” allows the Commission to set rates “based on the cost of providing service, including a reasonable return on investment.”³⁶ PG&E’s provision of electric and gas service requires the acquisition and construction of assets that will provide service to customers over many decades. As the Commission recently explained:

[T]he utility is provided the opportunity to recover its actual legitimate or prudent costs—determined by a public examination of the utility’s outlays—plus a fair return on capital investment as measured by the cost of obtaining capital in a competitive capital market. [¶] Investors will only provide capital for provision of utility services if they anticipate obtaining a return that is consistent with returns they might expect from employing their capital in an alternative use with similar risk.³⁷

The California Legislature agrees. It stated in AB 1054: “[t]he state has a substantial interest that its electrical corporations are operating in a safe and reliable manner, *and have access to capital at reasonable cost to make safety investments.*”³⁸ It recognized that the financial health of the utilities is important for customers and the state because it is necessary for the utilities “to provide safe and reliable electric and gas service, to reduce the risk of future catastrophes, to provide service at just and reasonable rates, to meet the state’s mandates to reduce carbon emissions, and to address the risks of climate change.”³⁹

The California Supreme Court described the regulatory compact as follows:

The basic principle [of ratemaking] is to establish a rate which will permit the utility to recover its cost and expenses *plus* a reasonable return on the value of property devoted to public use." It is thus elementary regulatory law that the "return" -- i.e., the profit -- of the utility is calculated solely on the rate base -- i.e., the capital contributed by its investors; the utility is not entitled to earn an

³⁶ D.19-05-020, p. 8.

³⁷ D.20-01-002, pp. 10-11.

³⁸ Assem. Bill No. 1054 (2019-2020 Reg. Sess.) § 2(c) (emphasis added).

³⁹ Pub. Util. Code, §854.2(a)(6).

additional profit on its expenses, but only to "recover" them on a dollar-for-dollar basis as part of the rates.⁴⁰

The Commission cannot substitute cost recovery with an arbitrary spending cap as TURN proposes as discussed in Section 2.5.3.4 below. This is especially true in today's economic environment. PG&E's costs are continuing to grow in large part due to necessary expenditures to reduce risks from destructive wildfires and to further the State's clean-energy public policy. We are also seeing rapidly increasing prices due to inflation.⁴¹ These are actual costs that cannot be ignored in a ratesetting proceeding.

The regulatory compact does not allow the Commission to adopt a revenue requirement that deprives PG&E of our opportunity to recover our actual costs of service. The legality of a process that would establish utility rates without regard to evidence of the utility's actual costs was addressed by the United State Supreme Court almost a century ago. The Supreme Court's decision remains true today:

It is impossible to ascertain what will amount to a fair return upon properties devoted to public service without giving consideration to the cost of labor, supplies, etc., at the time the investigation is made. An honest and intelligent forecast of probable future values made upon a view of all the relevant circumstances, is essential. If the highly important element of present costs is wholly disregarded such a forecast becomes impossible. Estimates for to-morrow cannot ignore prices of to-day.⁴²

The Commission's decision in this proceeding thus must be based on PG&E's substantial evidence of its **actual** costs to provide safe and reliable service rather than a fictional cost benchmark as TURN proposes and is discussed in Section 2.5.3.4 below.

⁴⁰ *Southern Cal. Edison Co. v. Public Utilities Com.*, (1978) 20 Cal.3d 813, 818-819 (internal citations omitted (emphasis added)).

⁴¹ Tr. Vol. 15, p. 2804:6-21, PG&E/Peterman.

⁴² *Missouri ex rel. Southwestern Bell Tel. Co. v. Public Service Com.*, (1923) 262 U.S. 276, 287-288.

1.4.2.1.2 The Commission Should Reaffirm That PG&E Has The Right And Obligation To Reprioritize GRC Funding To Address Emerging Needs.

The Commission's decision should reaffirm that PG&E should use its GRC revenue requirement to address highest priority work during the 2023 to 2026 GRC period. Of course, this GRC will address PG&E's funding needs for four rather than three years, making it even more likely that the outer-year forecasts that PG&E prepared in this case will not reflect emerging needs of the utility. The Commission has long recognized that, by their very nature, forecasts are not predictions, promises or guarantees, and that actual results vary from forecasts:

Ratemaking is not, nor has it ever been, an exact science that guarantees perfect results from all perspectives. Ratemaking, whether in a general rate proceeding or by an attrition mechanism, is essentially the art of estimating future events based on judgment that is as fully informed as possible. We know in prospective test year ratemaking that our adopted estimates of revenues and expenses may be at variance with actual hindsight results. Accordingly, we are not as concerned as some parties are about having ratemaking that is always perfect from the hindsight perspective. Rather we will continue our practice of adopting sound, informed estimates with the hope that utility management accepts the challenge and can somehow "do-it-for-less."⁴³

The Commission has also explained:

It is generally recognized that when a utility files a GRC, expenditure estimates are based on plans and preliminary budgets developed at least two years in advance of when they will actually be incurred. When the utility finalizes its budget just prior to the year when costs will be incurred or adjusts the budget during the year, new programs or projects may come up, others may be cancelled, and there may be reprioritization. *This process is expected and is necessary for the utility to manage its operations in a safe and reliable manner.*⁴⁴

The Commission should reaffirm this principle in the final decision so that PG&E does not risk penalties or disallowances because we shifted funding to meet higher priorities and new challenges.

⁴³ D.85-03-042, 17 CPUC2d 246, 254.

⁴⁴ D.11-05-018, p. 27 (emphasis added). The Commission made this point more succinctly in Finding of Fact 10: "A reprioritization process is expected and is necessary for the utility to manage its operations in a safe and reliable manner." *Id.* at p. 82.

1.4.2.2 Utility Rate Components

This section responds to directions from the ALJs to include basic ratemaking principles in the brief.⁴⁵ California utilities follow forecast ratemaking, meaning that the Commission sets a revenue requirement to cover an upcoming period. The first year of that rate case period is known as the test year. The following years are known as attrition (or post-test) years.

The test year revenue requirement is calculated as follows:⁴⁶

$$\text{Revenue Requirement} = O\&M + \text{Taxes} + \text{Depreciation} + (\text{Rate Base} * r) - OOR$$

where:

- O&M = expenses that include Operations & Maintenance (O&M) and Administrative & General (A&G) costs, such as labor, and employee medical costs.
- Taxes = Federal, state and local taxes,
- Depreciation = depreciation of plant (capital),⁴⁷
- Rate Base = net value of plant in service plus working capital,
- r = rate of return on invested capital, and
- OOR = other operating revenue.

1.4.2.3 Results Of Operations Model

PG&E requests that the Commission adopt its estimating method and Results of Operations (RO) Model used to calculate revenue requirements in this case. The estimating method gathers inputs on operating expense and capital components for CPUC-jurisdictional functions using a Unbundled Cost Category (UCC) format that supports a full summary of

⁴⁵ See Tr. Vol. 14, p. 2735:21 to 2736:18.

⁴⁶ See California Public Utilities Commission Policy & Planning Division, Utility General Rate Case – A Manual for Regulatory Analysts (Nov. 13, 2017) (GRC Manual), p. 19, <https://www.cpuc.ca.gov/-/media/cpuc-website/files/uploadedfiles/cpuc_public_website/content/about_us/organization/divisions/policy_and_planning/ppd_work/ppd_work_products_-2014_forward-/ppd-general-rate-case-manual-1-.pdf> (as of Oct. 21, 2022).

⁴⁷ See GRC Manual, p. 22 (“The annual depreciation cost can be written as: Annual cost (\$) = (Total asset value – Net salvage value)/Estimated service life.”).

earnings for each UCC.⁴⁸ The RO Model (used in all PG&E GRCs since 2007 and two Gas Transmission and Storage (GT&S) cases) maintains the UCC organization to compute revenue requirements that can be summarized to electric and gas distribution, electric generation, and GT&S functions.⁴⁹ Cal Advocates relied on the RO Model (with different inputs and one formula error correction as instructed by PG&E) to prepare its revenue requirements recommendation.⁵⁰

In response to the ALJs' request, Appendix D to this Opening Brief provides information on the RO Model used in GRC proceedings to establish the approved revenue requirements.⁵¹ Aligned with the utility's cost of service ratemaking formula, PG&E compiles the expenses and capital expenditures forecast and uses the RO Model to develop the revenue requirement. For O&M expenses and capital expenditures, PG&E provides the forecast at the major work category (MWC) level. For the Electric Distribution, Gas Distribution, Gas Transmission and Storage business units, the MWC forecasts are further broken down into the maintenance activity type (MAT) code level. Administrative and General costs include corporate services organization costs and companywide expense. These costs are in the RO Model by department such as Finance, or by cost type such as medical plan or property insurance.

1.5 Use Of PG&E's 2021 Forecast And Recorded Cost Data

PG&E's test year forecast was developed based on recorded year 2020 data and a forecast of 2021 and 2022 capital expenditures. This was the best data available to PG&E at the time it prepared its GRC and is consistent with Rate Case Plan requirements.⁵² The Scoping

⁴⁸ PG&E-10, p 17-3 lines 5-33.

⁴⁹ PG&E-10, p. 17-4, lines 1-10.

⁵⁰ CALPA-14, p. 3 line 8 to p. 4 line 5.

⁵¹ Tr. Vol. 14, p. 2735:21-28, p. 2736:22-28.

⁵² D.07-07-004, Appendix A, p. A-32, Item B.

Memo required PG&E to produce 2021 recorded year data in March 2022.⁵³ During the course of the proceeding, Cal Advocates requested 2021 recorded data during discovery on multiple occasions.⁵⁴ PG&E provided partial year recorded data when available but indicated to Cal Advocates that it would provide **final** verified 2021 recorded data in March 2022 pursuant to the Scoping Memo requirements and would not be able to continue to update the 2021 recorded year data in discovery responses.⁵⁵ Cal Advocates' testimony used for some – but not all – projects or programs interim unverified 2021 recorded data PG&E provided in data responses and also created a different forecast for some of the months in 2021 for which PG&E's data was not available prior to March 2022.⁵⁶ Thus, for some programs, Cal Advocates used PG&E's capital forecast of 2021 recorded data, and for other programs, Cal Advocates used a mixture of PG&E's interim (unverified) recorded data with Cal Advocates' own forecast for some of the later months in 2021. As PG&E Vice President Shilpa Ramaiya explained in her rebuttal testimony:

Cal Advocates takes an inconsistent approach to the issue of 2021 recorded costs. In some Exhibits, Cal Advocates recommends that the 2021 forecast PG&E provided in testimony be replaced by 2021 recorded costs. However, in other Exhibits, Cal Advocates does not make that recommendation.

In many cases, Cal Advocates makes recommendations based on an estimate of 2021 recorded costs that Cal Advocates derived by using partial year 2021 recorded data provided by PG&E early in the proceeding through discovery responses and adjusting it to reflect the full year. Confusingly, in some cases, Cal Advocates used the 2021 full year recorded data provided by PG&E on March 9, 2022 for its recommendations, but in many cases made recommendations based on incomplete 2021 partial year recorded data that Cal Advocates adjusted and decided not to update with 2021 full year recorded data.⁵⁷

⁵³ Scoping Memo, p. 14.

⁵⁴ See Exhibits CALPA X-2, CALPA X-3, CALPA X-4, CALPA X-5, CALPA X-6, CALPA X-7, CALPA X-8 and CALPA X-9.

⁵⁵ *Ibid.*

⁵⁶ PG&E-14, p. 2-2, lines 23-25 and p. 2-4, line 5 to p. 2-5, line 4.

⁵⁷ PG&E-14, p. 2-4, lines 5-18 (internal footnotes omitted).

The Commission should not approve or use in the decision Cal Advocates' partial year recorded data and newly created 2021 forecasts. The Commission should instead *consistently use* either the 2021 capital forecast or the 2021 recorded data PG&E produced in March 2022. It should not supplant this data with partial year recorded data plus a new forecast produced by Cal Advocates. Further, parties should not be allowed to pick between the recorded and forecast 2021 data to support their preferred outcome or create a different forecast for some of the months of 2021 as Cal Advocates has done, as this would provide inconsistent results as the actual 2021 data will be higher in some areas and lower in the others.⁵⁸

The Commission addressed the use of base year + one data in the Sempra utilities' 2019 GRC and decided that it was generally more appropriate and consistent to use the original forecast:

ORA recommends using 2017 recorded costs instead of SoCalGas' 2017 forecasts for all the proposed capital projects for Gas Distribution. With respect to the use of 2017 recorded costs versus 2017 forecasts, the rate case plan requires that the GRC application use the most recent data available at the time the application is filed. In this case, the GRC application was filed in late 2017 and so the most recent data available at the time of preparing and filing the application is the base year or 2016 data.

As the application progresses, it is often the case that newer data becomes available such as 2017 recorded data in this instance. While we note that recorded costs for 2017 are more accurate and more recent than the 2017 forecasts that are included in the application, we find that it is not feasible to constantly update data for the entire application. It is also not practical to update all data in the GRC because of the vast amounts of data included in the application.

As such, we find that selectively updating only certain data or in this case applying 2017 recorded costs in some instances but not in others may lead to inconsistent results. *This is because not all data that was submitted with the application is being updated. For example, updating select data to 2017 recorded costs in one area which results in a lower value than the 2017 forecast would be inconsistent if another update in a different area would result in a higher value than the forecast but was not applied.*

We do however recognize that there are instances where it is prudent, necessary, and reasonable to apply updated data in select areas and we exercise our discretion in doing so in appropriate cases. But for this GRC, based on the

⁵⁸ PG&E-14, p. 2-5, lines 6-10.

explanation above, we will generally not apply select updating of data if the sole reason for doing so is simply to update data without any explanation why the updated data should be applied. In this case, we find it more appropriate to apply the 2017 forecasts for all the capital projects.⁵⁹

The Commission should determine in this proceeding whether to consistently use the recorded or forecast capital for 2021.⁶⁰ PG&E does not oppose either result as long as the result is applied consistently throughout the proceeding. The Commission should decline, however, Cal Advocates' proposal to selectively use the recorded data or Cal Advocates' new forecasts for 2021 recorded data that are based partially on recorded data and partially on its own newly-created forecast.

1.5.1 Uncontested Expense

PG&E forecasts expense costs for hundreds of different programs, many of which are uncontested. Appendix A to this Opening Brief includes four tables that list: (1) the uncontested expense programs by MWC or MAT; (2) the uncontested capital programs by MWC or MAT; (3) the uncontested department costs; and (4) the uncontested companywide expenses. Overall, approximately 34 percent of PG&E's expense forecast, 59 percent of PG&E's forecast for department costs, and 9 percent of PG&E's companywide expense forecast are uncontested.⁶¹

1.5.2 Uncontested Capital

PG&E forecasts capital costs for hundreds of different programs across PG&E's lines of business, many of which are uncontested. Appendix A includes the uncontested capital programs by MWC or MAT. Approximately 17 percent of PG&E's capital forecasts are uncontested.

⁵⁹ D.19-09-051, pp. 59-60 (emphasis added).

⁶⁰ The Commission has used the base year + one recorded year data in some GRC decisions in this situation on agreement of the parties. *See, e.g.*, D.19-09-025, p.243 (citing PG&E agreement to use base year + one recorded data for capital true up); D.20-12-005, p. 92.

⁶¹ See Appendix A. Uncontested amounts reflect PG&E's forecast plus errata and concessions but exclude PG&E's Update Testimony.

1.5.3 Uncontested Non-Forecast Issues, Balancing Accounts, And Memorandum Accounts

We presented non-forecast issues in our GRC for which we request approval from the Commission, such as the elimination of certain existing balancing accounts and memorandum accounts and other non-financial items. A substantial number of these issues are uncontested. Appendix B lists the non-forecast issues that are uncontested including: (1) balancing and memorandum accounts that PG&E requests be continued with no modifications; (2) balancing and memorandum accounts that PG&E requests be continued with modifications; (3) balancing and memorandum accounts that PG&E requests be closed at the end of the rate case period (December 31, 2022); and (4) new proposed balancing accounts for Gas Operations; and (5) additional uncontested non-forecast issues. In Appendix B, PG&E provides citations to the evidence supporting these requests. Because these requests are well supported by the evidence and are uncontested, we request that the Commission approve the non-financial requests in Appendix B.

1.6 Other General Issues

1.6.1 Inclusion Of Initial And Update Testimony Forecasts

Throughout the brief we are providing two sets of forecast numbers – the expense and capital forecasts in our opening and/or rebuttal testimony and the expense and capital forecasts based on the Update Testimony reflecting our proposed inflation adjustment and other adjustments. We are also providing parties’ proposed reductions or disallowances so that the ALJs and the Commission can have a full and complete view of the forecasted costs for disputed programs and parties’ proposed reductions. In addition, in Sections 5, 7 and 9, we are providing the agreed to forecasts for specific programs, MWCs, and MATs based on the stipulations that we have entered into with parties for Energy Supply, IT and A&G. Appendix H includes a series

of tables showing the forecasts in opening and/or rebuttal testimony, the forecasts based on the Update Testimony and the difference between them by line of business.⁶²

1.6.2 Disputed Balancing And Memorandum Accounts

While a substantial number of PG&E's balancing and memorandum account requests are undisputed, there are contested proposals. In Appendix C, we list all of the disputed memorandum and balancing accounts and provided a summary of PG&E's position, cite to the evidence supporting our proposal, and identify the section of the Opening Brief that addresses the disputed memorandum or balancing account.

1.6.3 Glossary

The utility industry is filled with acronyms. We have used acronyms throughout our brief for brevity, but also recognize that it is easy to forget what an acronym means. All of the acronyms used in this brief are defined in Section 17 (Glossary). In some cases, acronyms can have two different meanings. Where an acronym has two different meanings, we have included both in the Glossary and tried to make clear with context which meaning it has in the Opening Brief.

1.6.4 Stipulated Outcomes

Following the evidentiary hearings, we have continued to engage with the other parties to this proceeding to attempt to narrow the issues in dispute. We were pleased to be able to reach stipulations on the forecasts for the following exhibits:

- Exhibit PG&E-05 – Energy Supply (most disputed issues);
- Exhibit PG&E-07 - Shared Services and Information Technology (Enterprise Records and information Management and Data Governance only); and
- Exhibit PG&E-09 - Administrative and General Expenses (all disputed issues).

⁶² Because the stipulations for Energy Supply, IT, and A&G were only finalized this week, we did not have an opportunity to reflect the impact of these agreements in Appendix H. We will provide an updated version of Appendix H with our Reply Brief.

Our stipulations to resolve disputed forecasts for these areas are discussed in Sections 5, 7.8, 7.9, and 9 below and the stipulations are included as Appendices E (Energy Supply), F (IT), and G (A&G).

1.6.5 Length Of Brief

Finally, we are mindful of the ALJs' feedback during and after the hearings that parties' briefs be succinct and focus on key disputed issues. We recognize that our Opening Brief is lengthy. In preparing this brief, we faced two challenges. This GRC is unlike past GRCs in that two rate cases – the GRC and the GT&S rate case – have now been combined. This has resulted in a substantial number of new issues in the 2023 GRC and thus a longer brief to address these issues. In addition, this GRC has involved issues unlike any other recent GRC. While we tried to keep this brief as succinct as possible, we felt that it was critical to fully present the evidence and the arguments that support PG&E's request to aid the Commission to reach a conclusion based on a complete record. Given the safety and reliability implications for all of the customers and communities that we serve, we felt it essential to address all of the critical issues raised in this proceeding.

2. RISK MANAGEMENT, SAFETY, OPERATING RHYTHM AND CLIMATE (EXHIBIT PG&E-02)

2.1 Enterprise Risk Management

2.1.1 Enterprise Risk Management And Policy

2.1.1.1 PG&E's Enterprise Risk Organization

PG&E's Enterprise and Operational Risk Management (EORM) facilitates risk-informed, data-driven decision-making that results in measurable risk reduction. To accomplish this, PG&E's EORM program provides the lines of business with tools, methods, and technical support to:

- Identify risks that can lead to severe or catastrophic safety, reliability, and financial consequences for our customers;
- Develop and implement mitigations and controls that have the greatest potential to reduce those risks and are the most cost-effective options for managing risk; and
- Drive accountability and transparency in monitoring and reporting risk related information.

One of the key programmatic improvements PG&E has instituted for managing risk is instituting steering committees and implementation teams focused on ensuring that the most effective mitigations are selected and delivered for PG&E's highest priority risks. PG&E recognized the need for additional governance around managing our highest scoring safety risk and in 2020, formed the Wildfire Risk Governance Steering Committee (WRGSC) to ensure that: (1) the wildfire workplan is comprised of the highest priority, risk mitigating work consistent with safety focused investments, asset strategy and operational needs; (2) the approved risk-informed work plan is completed; and (3) the execution and the associated quality of the work has appropriate oversight.⁶³

The WRGSC is primarily focused on system hardening, enhanced vegetation management, inspections and repairs/replacements, the Public Safety Power Shutoff (PSPS) program, and other wildfire mitigation work. The WRGSC is chaired by the Chief Risk Officer

⁶³ PG&E-02, p. 1-7, lines 16-26.

(CRO) and includes as its members senior leaders in Electric Operations Asset Management, Risk Management, Major Projects and Programs, Wildfire Safety and Public Engagement, Public Safety Specialists, and PG&E’s Chief Audit Officer.⁶⁴

In addition, in 2021, PG&E created a Wildfire Risk Management organization focused on ensuring that the most effective mitigations are selected and delivered for PG&E’s highest priority risks. The Wildfire Risk Management organization is headed by the CRO and comprised of a cross functional team with responsibility for all aspects of wildfire risk mitigation.⁶⁵

2.1.1.2 The Commission’s Risk-Based Decision-Making Framework

The Commission has developed a risk-based decision-making framework (RDF) to increase transparency and accountability for how utilities prioritize and manage safety risk.⁶⁶ The RDF is relevant to several of the issues that intervenors raise with respect to PG&E’s risk modelling, so PG&E provides a short overview here.

The initial phase of the RDF is the Safety Model Assessment Proceeding (S-MAP). The S-MAP is intended to (1) “allow parties to understand the models the utilities propose to use to prioritize ... projects ... to mitigate risks; and (2) allow the Commission to establish standards and requirements for those models.”⁶⁷ The S-MAP Settlement Agreement⁶⁸ establishes the “minimum required steps for large Utilities to take to analyze risk and mitigations for the RAMP

⁶⁴ PG&E-02, p. 1-7, lines 27-34.

⁶⁵ PG&E-02, p. 1-6, lines 15-20.

⁶⁶ CPUC, Risk Assessment and Safety Analytics, Risk-Based Decision-Making Framework, <<https://www.cpuc.ca.gov/about-cpuc/divisions/safety-policy-division/risk-assessment-and-safety-analytics>> (as of Oct. 23, 2022).

⁶⁷ D.18-12-014, p. 5.

⁶⁸ The S-MAP Settlement Agreement was adopted with modifications in D.18-12-014 as part of the S-MAP proceeding. The S-MAP Settlement Agreement was signed by the PG&E, Southern California Edison Company, Southern California Gas Company, San Diego Gas and Electric Company, The Utility Reform Network, Energy Producers and Users Coalition, Indicated Shippers, and the Office of Ratepayer Advocates.

and GRC.”⁶⁹ The S-MAP Settlement Agreement requires utilities to build a Multi-Attribute Value Function (MAVF).⁷⁰ PG&E uses the MAVF to identify our top safety, reliability, and financial risks and to evaluate and rank alternative risk mitigation programs.⁷¹ The benefit of using the MAVF is that it allows PG&E to compare our different enterprise risk events by positioning the risk scores on a common scale (the MAVF risk unit).⁷² PG&E’s implementation of the MAVF is based on guidance in the S-MAP Settlement Agreement. PG&E’s MAVF reflects PG&E’s focus on mitigating low frequency/high- consequence risk events without neglecting high probability/low consequence risk events.⁷³

The risk scores yielded by the MAVF can be used to calculate a Risk Spend Efficiency (RSE) for proposed mitigations based on the estimated risk reduction of that mitigation divided by its forecast cost. The S-MAP Settlement Agreement requires utilities to provide a relative ranking of mitigations by RSE but explicitly states that utilities are not required to select their mitigation strategies based solely on RSE ranking.⁷⁴

The next element in the RDF is the Risk Assessment and Mitigation Phase (RAMP). The RAMP consists of a regulatory review and public vetting process for each of California’s four major investor-owned utilities (IOUs). It includes a detailed analysis of safety risk threat assessments with attendant mitigation proposals and estimated costs. PG&E is required to file a RAMP application including a RAMP Report describing: our risk assessment and modeling

⁶⁹ D.18-12-014, p. 10.

⁷⁰ D.18-12-014, p. 22, Step 1A.

⁷¹ PG&E-15-E, p. 1-6, lines 11-14.

⁷² PG&E-15-E, p. 1-6, lines 16-18.

⁷³ PG&E-02, p. 1-12, lines 3-6. PG&E describes our MAVF and how it complies with the S-MAP Settlement Agreement in A.20-06-012, RAMP Report (June 30, 2020), Ch. 3.

⁷⁴ D.18-12-014, Attachment A (S-MAP Settlement Agreement), Appendix A, p. A-14, No. 26.

process using the S-MAP framework; the risk modeling results; and the options to mitigate its risks. PG&E filed our 2020 RAMP Report on June 30, 2020.⁷⁵

The GRC is the final step in the RDF. In its 2023 GRC, PG&E includes a description of the risk modeling process and results and requests funding for our proposed mitigation programs.⁷⁶ PG&E discusses our GRC risk-informed decision-making process in Section 2.1.1.3 below.

Finally, in 2020 the Commission initiated a Risk-Based Decision-Making Framework OIR (RDF OIR) to “build on [the] requirements for the utility risk assessment and mitigation framework adopted in [the S-MAP and associated rulemaking].”⁷⁷ The RDF OIR is still ongoing. On August 8, 2022, the Commission issued a ruling in the RDF OIR providing a Phase II Staff Proposal from the Commission’s Safety Policy Division for comment (SPD Staff Proposal).⁷⁸ The SPD Staff Proposal identifies shortcomings in the MAVF and RSE methodology utilized in the S-MAP and will be discussed below in Section 2.3.1 in the context of TURN’s recommendations.

⁷⁵ PG&E’s 2020 RAMP Report, A.20-06-0912 (June 30, 2020). The 2020 RAMP Report is included in PG&E’s workpapers, PG&E-02, pp. WP 1-134 to WP 1-911.

⁷⁶ There are two other elements of the CPUC RDF – the Risk Spending Accountability Report (RSAR) and the Safety and Performance Metrics (SPM) Report – that are not material to the risk management issues raised by the intervenors. RSAR and SPM Reports are described in PG&E’s opening testimony. PG&E-02, p. 1-25, line 10 to p. 1-26, line 3.

⁷⁷ *Assigned Commissioner’s Scoping Memo and Ruling* (Nov. 2, 2020) R.20-07-013, p. 1. The Commission has dedicated Phase I, Track 1 and Phase II to address and resolve issues to update the original S-MAP requirements using the evaluations of the first IOU RAMP Reports, including issues regarding the MAVF. The Commission issued D.21-11-009 addressing Phase I, Track 1 issues on November 4, 2021. A proposed decision addressing Phase II issues is expected in November 2022 (*Assigned Commissioner’s Ruling Issuing Phase II Roadmap for Comment* (Feb. 16, 2022) R.20-07-013, Attachment, p. 2.).

⁷⁸ PG&E-29. The SPD Staff Proposal is Attachment A to the Commission ruling.

2.1.1.3 PG&E's Risk-Informed Investment Prioritization Process

When PG&E developed our prioritized portfolio for this GRC, the overall objectives for each line of business (LOB) were to: (1) prioritize safety and risk reduction initiatives; (2) focus on improving reliability; and (3) address customer related and load growth work.⁷⁹ At the time, PG&E was transitioning between retiring our risk informed budget allocation (RIBA)⁸⁰ standard and implementing a new process.⁸¹ In this transition period, LOBs relied on different methods to evaluate and prioritize their risk-informed work portfolios. For example, Electric Operations relied on its Loading Order and Circuit Protection Zone Rankings to prioritize its GRC portfolio. The top priorities in the Loading Order are work that addresses immediate safety emergencies and work that mitigates wildfire ignitions. The Circuit Protection Zone Ranking incorporated risk ranking prioritization, wildfire spread modeling and assessed the pace, scope, and combination of planned risk mitigations.⁸² PG&E describes how we factored RSE and other risk related information into our Electric Distribution investment prioritization decisions in our rebuttal testimony.⁸³

Gas Operations performed a bottom-up forecast by the subject matter experts in each asset family with the objective to invest in programs that address risks while considering execution constraints, such as resource availability, periods of higher demand, permitting timeliness, and costs.⁸⁴ Gas Operations then conducted a detailed review of our portfolio with a focus on emergency restorative and preventative work that supports immediate response to

⁷⁹ PG&E-02, p. 1-10, lines 10-14.

⁸⁰ RIBA was the risk scoring procedure PG&E used to risk inform our 2020 GRC forecast.

⁸¹ PG&E-02, p. 1-9, line 9 to p. 1-10, line 14.

⁸² PG&E-04, p. 2-18, line 16 to p. 2-19, line 13.

⁸³ PG&E-17, Ch. 3.

⁸⁴ PG&E-03, p. 2-20, lines 8-13.

public and workforce safety, customer commitments and load growth, compliance-mandated work, and risk reduction activities.⁸⁵

2.1.2 Integrating RAMP Into The GRC

PG&E filed our RAMP Report on June 30, 2020 (Application (A.) 20-06-012).⁸⁶ The Safety Policy Division (SPD) filed a report evaluating PG&E's RAMP Report on November 25, 2020 (SPD Report).⁸⁷ PG&E also received comments from other interested parties on January 15, 2021. PG&E filed opening and reply comments on January 15 and 29, 2021, respectively.⁸⁸

SPD confirmed that PG&E's methodology conformed to the steps outlined in the S-MAP Settlement Agreement. Further, SPD found that PG&E's "2020 RAMP showed marked improvements in risk modeling rigor, data quality, and transparency over previous rate cases."⁸⁹ PG&E responded to both SPD's and the other parties' comments and incorporated much of their feedback into the risk analysis presented in the 2023 GRC. PG&E describes our responses in greater detail in our prepared testimony.⁹⁰ In addition, in response to SPD and parties' feedback, PG&E updated certain information provided in the 2020 RAMP report; this is also described in greater detail in PG&E's prepared testimony.⁹¹ PG&E's prepared testimony also describes updates that PG&E has made since the 2020 RAMP Report to improve the enterprise

⁸⁵ PG&E-03, p. 2-20, line 22 to p. 2-22, line 24.

⁸⁶ PG&E's 2020 RAMP Report is included in PG&E's opening testimony workpapers, PG&E-02, WP 1-134 to WP 1-911.

⁸⁷ A.20-06-012, SPD Staff Evaluation Report on PG&E's 2020 RAMP Application (November 25, 2020).

⁸⁸ A.20-06-012, PG&E's Comments on SPD's Evaluation of PG&E's RAMP Report (January 15, 2021) (PG&E Opening Comments); A.20-06-012, PG&E's Reply Comments in Response to Comments on PG&E's RAMP Report and SPD's Evaluation (January 29, 2021).

⁸⁹ A.20-06-012, SPD Report, p. 4.

⁹⁰ PG&E-02, p. 1-16, line 10 to p. 1-19, line 22.

⁹¹ PG&E-02, p. 1-19, lines 23 to p. 1-20, line 22.

risk model and RSE calculations.⁹² In response to SPD's feedback, in this GRC PG&E calculated RSEs for a larger number of risk mitigations than in the RAMP Report and calculated RSEs for controls per the S-MAP Settlement Agreement (compared to the two pilot controls for which RSEs had been calculated in the RAMP).⁹³

2.2 Risk Modeling Issues

TURN raises issues regarding PG&E's risk modeling and argues that: (1) PG&E's MAVF is flawed; (2) the tranches used in PG&E's risk analysis are insufficiently granular; and (3) PG&E does not adequately model the impact of operational failure as a driver of risk. PG&E addresses these arguments below.⁹⁴

2.2.1 PG&E's MAVF Implementation Is Reasonable

TURN argues that PG&E's MAVF is flawed and proposes an alternative MAVF. In particular, TURN objects to PG&E's use of a non-linear scaling function to transform the natural units of safety (equivalent fatalities) and financial (dollars) attributes to scaled MAVF units because that approach gives a higher relative value to preventing events that PG&E has categorized as having critical or catastrophic consequences compared to preventing events with minor or moderate consequences that happen with relatively greater frequency.⁹⁵ TURN also claims that PG&E's MAVF implies a Statistical Value of Life (SVL)⁹⁶ equal to \$100 million,

⁹² PG&E-02, p. 1-21, line 1 to p. 1-22, line 13.

⁹³ PG&E-02, p. 1-18, lines 1-11.

⁹⁴ Mussey Grade Road Alliance (MGRA) and the Coalition of Utility Employees (CUE) both note that PG&E's (and TURN's) risk models do not explicitly incorporate certain effects of wildfire including the health impacts of wildfire smoke, indirect costs due to business, travel, and labor market disruption, and aesthetic and environment degradation. PG&E-15-E, p. 1-38, lines 4-15. PG&E will continue to refine our wildfire risk models going forward.

⁹⁵ TURN-02, p. 28, line 3 to p. 29, line 14.

⁹⁶ Although TURN's witness uses the term SVL, this concept is more commonly known as the Value of Statistical Life (VSL). See, e.g., <https://www.transportation.gov/sites/dot.gov/files/docs/2016%20Revised%20Value%20of%20a%20Statistical%20Life%20Guidance.pdf> (as of Oct. 31, 2022).

which is much higher than accepted SVL estimates used by several agencies of the U.S. government in the risk assessments.⁹⁷

TURN's criticisms of PG&E's MAVF are unfounded. MAVF Principle 5 of the S-MAP Settlement Agreement explicitly allows for the use of a non-linear scaling function in the MAVF and provides that the scale can be constructed to "captur[e] aversions to extreme outcomes...."⁹⁸ PG&E's MAVF implementation is reasonable and follows from our focus on preventing low-frequency/high-consequence risk events without neglecting high-frequency/low-consequence risk events.⁹⁹ PG&E's rebuttal testimony explains why tail risk – the risk posed by infrequent but potentially catastrophic events such as large scale wildfires – is a critical aspect of risk that cannot be ignored in MAVF scoring, and why using a linear function, as TURN proposes, does not adequately capture that tail risk.¹⁰⁰ The premium PG&E places on identifying and mitigating potentially catastrophic risk events reflects both our commitment to permanently reduce wildfire risk in the highest risk areas of our service territory¹⁰¹ and California's overall commitment to reduce wildfire risk.¹⁰² PG&E notes that the recently-issued SPD Staff Proposal recommends significant changes to the S-MAP approach to MAVF implementation, but does not propose to change the portion of the S-MAP Settlement Agreement

⁹⁷ TURN-02, p. 19, lines 8-16.

⁹⁸ D.18-12-014, Attachment A, Appendix A, p. A-5, No. 6.

⁹⁹ PG&E-02, p. 1-12, lines 4-6.

¹⁰⁰ PG&E-15-E, p. 1-8, line 1 to p. 1-9, line 12. See also PG&E-15-E, p. 1-22, line 5 to p. 1-30, line 30.

¹⁰¹ PG&E describes our plans to permanently reduce wildfire risk in certain HFTD areas in PG&E-17, Ch. 4.

¹⁰² See e.g., Pub. Util. Code § 8386(a) that requires electric utilities to minimize the risk of catastrophic wildfires; and Pub. Util. Code § 963(b)(3) ("It is the policy of the state that the Commission and each gas corporation place safety of the public and gas corporation employees as the top priority. The Commission shall take all reasonable and appropriate actions necessary to carry out the safety priority policy of this paragraph. . . .").

that allows IOUs to use a non-linear scaling function to capture risk preferences, as PG&E has done is this GRC.¹⁰³

TURN's claim that PG&E's MAVF implies an SVL of \$100 million is incorrect. As PG&E explained in detail in our rebuttal testimony, use of a non-linear scaling function means that the SVL varies depending on the level of Safety and Financial losses. TURN ignores this and assumes that the SVL calculated at the maximum levels of Safety and Financial losses is the SVL across the entire spectrum of potential consequences.¹⁰⁴ Moreover, the S-MAP Settlement Agreement makes no mention of either a direct or implied target SVL. Stakeholders are currently discussing this issue in the Commission's ongoing RDF OIR which PG&E believes is the appropriate venue for the Commission to address this issue.¹⁰⁵

2.2.2 PG&E's Use Of Tranches Is Reasonable

A tranche, as defined by the S-MAP Settlement Agreement, is based on how risks and assets are managed by each utility, given data availability and model maturity, in order to achieve as deep a level of granularity as reasonably possible. For the purposes of the risk analysis, each element (*i.e.*, asset or system) contained in the identified tranche would be considered to have a homogeneous risk profile (*i.e.*, considered to have the same likelihood of risk event and consequence of risk event).¹⁰⁶

TURN argues that PG&E's tranches are insufficiently granular and that large scale capital programs such as undergrounding should be based on tranche-level RSEs.¹⁰⁷ TURN

¹⁰³ PG&E-29, Attachment A, p. 9.

¹⁰⁴ PG&E-15-E, p. 1-9, lines 15-18. See also PG&E-15-E, p. 1-31, line 1 to p. 1-34, line 15.

¹⁰⁵ PG&E-15-E, p. 1-9, lines 18-22. See also, PG&E-15-E, p. 1-34, line 16 to p. 1-35, line 2.

¹⁰⁶ PG&E-15-E, p. 1-13, lines 13-19 (citing D.18-12-014, Attachment A, Appendix A, p. A-11, No. 14.).

¹⁰⁷ TURN-02, p. 47, line 1 to p. 52, line 14.

also argues that PG&E’s tranches used for gas distribution risk analysis are inadequate and do not meet the requirements of the S-MAP Settlement Agreement.¹⁰⁸

PG&E’s tranches are reasonable for risk management purposes and are consistent with the S-MAP Settlement Agreement because they are based on the way PG&E manages risks and assets and reflects a level of granularity that is realistic and presently achievable.¹⁰⁹ Moreover, PG&E does not use the tranches from our risk bowties to prioritize work in large capital projects. For example, PG&E’s system hardening undergrounding workplan is informed by the Wildfire Distribution Risk Model that calculates wildfire risk probabilities of ignition and consequence scores for the thousands of individual circuit segments that comprise the overhead distribution system in the HFTDs.¹¹⁰ The Gas Operations operational risk models each contain millions of pipe segments and each of those pipe segments have their own risk characteristics. This is too granular for RAMP/GRC risk models, but it does provide insight in the creation of meaningful and reasonable tranches that strike a balance between too few and too many tranches.¹¹¹

TURN raises some specific concerns regarding the granularity of tranches developed for Gas Operations. These issues are addressed in Section 3.2.2.1 of this brief.

2.2.3 TURN’s Analysis Of Operational Failure Is Not Correct

TURN argues that PG&E does not adequately model the impact of operational failure – i.e., failure by PG&E to meet compliance requirements – as a driver of risk¹¹² and claims that properly accounting for that driver would result in a greater focus on compliance programs and

¹⁰⁸ TURN-02, p. 80, line 18 to p. 87, line 12.

¹⁰⁹ PG&E-15-E, p. 1-13, line 27 to p. 1-14, line 3.

¹¹⁰ PG&E-15-E, p. 1-14, lines 1-7 (citing PG&E-4, p. 3-17, Table 3-3, line 4).

¹¹¹ PG&E-15-E, p. 1-14, lines 7-12 (citing PG&E-16, Ch. 3, Section C.1).

¹¹² TURN-11, p. 13, line 3 to p. 16, line 17.

less focus on capital intensive mitigation strategies such as system hardening and undergrounding.¹¹³

TURN's criticism is unfounded. PG&E classifies the events that TURN ascribes to "operational failure" as equipment failure or vegetation contact within the modeling framework. PG&E's classification is reasonable and appropriate because the bow tie analysis generally takes readily available, observable, and/or proximate cause of a risk event as a driver.¹¹⁴ PG&E's classification by proximate cause helps with the assessment of risk drivers that should be targeted via risk management programs and helps in evaluating program effectiveness. Within the modeling framework, work that manages/reduces risk is modeled as a program targeting specific risk drivers (e.g., equipment failure), especially if the relative riskiness varies by tranche of assets. The relative riskiness of a driver informs how PG&E prioritizes work to mitigate risk, and that relative riskiness is based on classification of historical events by driver.¹¹⁵ This allows PG&E to determine which risk drivers should be targeted by risk management programs and provides valuable insight into mitigation effectiveness and opportunities for program improvement.

Compliance with existing laws, regulations, and regulatory commitments, such as targets in the Wildfire Mitigation Plan (WMP), are among PG&E's highest priorities. However, given the ever-increasing level of risk, a policy of compliance alone is not sufficient. To reduce risk, PG&E must implement programs designed to mitigate specific risk drivers. With respect to undergrounding, PG&E acknowledges that up to a point, compliance programs and quality assurance/quality control can be more cost effective risk reduction methods than mitigations such as undergrounding. However, these control programs are only meant to manage risk – i.e., to maintain risk at its current levels. To reduce risk, PG&E needs to move beyond control

¹¹³ TURN-02, p. 73, lines 1-9.

¹¹⁴ PG&E-15-E, p. 1-39, line 27 to p. 1-40, line 2.

¹¹⁵ PG&E-15-E, p. 1-40, lines 15-22.

programs to mitigations. For this GRC, PG&E is executing comprehensive programs that focus on reducing ignition events in locations that have high probability of ignition from equipment failure and high wildfire consequence. PG&E's comprehensive program includes controls (*e.g.*, inspections of distribution electric lines and equipment, pole inspections, and maintenance of overhead and underground equipment), proven mitigations (*e.g.*, overhead system hardening, undergrounding, single phase reclosers, and transformer replacements) and new, innovative mitigations (*e.g.*, Enhanced Powerline Safety Setting (EPSS)).¹¹⁶ Only through a combination of existing compliance programs and new mitigation programs will PG&E be able to significantly reduce the risks for our customers and our communities. TURN's proposal that PG&E stick with a bare bones approach to risk mitigation through existing compliance programs will not significantly move the needle on reducing risk, nor will it benefit our customers and communities in the long run.

2.3 Risk Spend Efficiency

TURN and Cal Advocates raise three substantive issues with respect to PG&E's use of RSEs: (1) TURN argues that RSE values can be easily converted to benefit cost ratios and that decisions on program funding should be based on these benefit-cost ratios;¹¹⁷ (2) TURN recommends cancelling gas safety programs based on their low RSE scores and significantly reducing the forecast for other gas safety programs;¹¹⁸ and (3) Cal Advocates requests that the Commission order PG&E to calculate RSEs for all MAT codes in the next GRC.¹¹⁹

¹¹⁶ PG&E-17, p. 3-11, line 10 to p. 3-13, line 28.

¹¹⁷ TURN-02, p. 39, lines 3-5 and p. 46, lines 9-20.

¹¹⁸ See TURN-02, p. 108, line 8 to p.127, line 3 (describing gas programs TURN is proposing to eliminate); TURN-04, p. 11, lines 5-21 (describing 66% reduction in the in-line upgrade program for gas transmission pipelines).

¹¹⁹ CALPA-06, p. 27, lines 17-24.

2.3.1 The Commission Should Not Adopt TURN's Flawed Proposal To Convert RSEs Into Benefit-Cost Ratios

TURN claims that PG&E's RSE values can be easily converted to benefit-cost ratios through a mathematical transformation of the MAVF by dividing PG&E's RSEs by five.¹²⁰ TURN further argues that decisions on program funding should be based primarily on these benefit-cost ratios.¹²¹

TURN's recommendation should not be adopted for three independent reasons. First, TURN's methodology for converting PG&E's RSE values to benefit-cost ratios is flawed because it disregards the fact that PG&E's MAVF scaling function is non-linear, as permitted by the S-MAP Settlement Agreement, and therefore does not provide a single "weighted scaled unit" from which a benefit-cost ratio can be calculated.¹²² TURN's arbitrary choice of one particular value (\$200 million) for a weighted scaled unit results in an invalid benefit-cost ratio. PG&E rebuttal testimony contains a more detailed discussion of this issue.¹²³

Second, TURN's attempt to convert RSEs to benefit-cost ratios and then use those ratios mechanically to establish funding guidelines is, at best, premature and is inconsistent with the S-MAP Settlement Agreement in its current form. Even if TURN's benefit-cost calculation methodology were correct, which it is not, TURN's approach assumes a degree of precision in MAVF and RSE estimates that simply does not exist. As PG&E explains in detail in our rebuttal testimony, RSEs are inherently uncertain and are highly sensitive to alternative MAVF specifications and other uncertain inputs such as mitigation effectiveness assumptions and future changes in the risk landscape.¹²⁴ TURN's proposal assumes that RSEs are stable, are estimated with precision, and can be used to determine the value of risk mitigation program in an absolute

¹²⁰ TURN-02, p. 39, lines 3-5.

¹²¹ TURN-02, p. 46, lines 9-20.

¹²² PG&E-15-E, p. 1-19, lines 12-18.

¹²³ PG&E-15-E, p. 1-18, line 9 to 1-20, line 18.

¹²⁴ PG&E-15-E, p. 1-36, line 3 to p. 1-39, line 22.

sense. The reality is that estimated RSEs are contingent on model formulation and inputs that are inherently imprecise.¹²⁵ In his opening remarks at the evidentiary hearings, Commissioner Reynolds specifically cautioned against such “false precision” when evaluating the balance between risk reduction and cost:

As we consider this challenge [the need for utilities to prioritize safety projects to maximize the effective use of ratepayer dollars to achieve risk reduction], we must be attentive to false precision where there is uncertainty surrounding the key measures of risk, cost, and project timing. Californians deserve operational excellence from their utilities, and operational excellence in planning, including accounting for uncertainty.¹²⁶

While PG&E believes that MAVF models and RSEs do provide some insight into the relative magnitude of risks and the relative cost-effectiveness of proposed programs to mitigate those risks, MAVF model development and RSEs have not reached the level of maturity where they can reasonably be used in the manner that TURN proposes.¹²⁷ Dr. Yumi Oum, who oversees PG&E’s Enterprise and Operational Risk Analytics team, responded to a question from TURN at hearings about whether a mitigation with a higher RSE is more cost-effective than one with a lower RSE by describing the uncertainty of RSE estimates and the MAVF calculation and concluded:

At this stage of RSE calculation, this – I note that this is the first GRC filing since [the] S-MAP settlement decision was adopted. And I think there is a lot of room for improvement in increasing the accuracy and understanding the uncertainty around different RSE estimates. So at this point, we will not be comfortable

¹²⁵ SoCalGas/SDG&E/SCE-1, p. 7, lines 10-12.

¹²⁶ See Tr. Vol. 4, 509:14-24, CPUC/Reynolds.

¹²⁷ TURN notes that while the S-MAP Settlement Agreement recognizes that mitigation strategies need not be based solely on RSE ranking, it also requires PG&E to explain our rationale for selecting those mitigation including factors other than RSEs. See TURN-02, p. 46, lines 9-20. PG&E notes that for all programs it is forecasting in this rate case—regardless of RSE—it provided support for our forecast in the form of direct testimony, supporting workpapers and responses to data requests.

looking at ... two RSE numbers and conclud[ing that] one is more cost-effective in reducing the risk versus the other.¹²⁸

As Sumeet Singh, PG&E's Chief Risk Officer, explained at hearings: "I think our position continues to be that the use of RSEs is one input, which is again, consistent with the S-MAP and should not be used as a sole determining factor as [a] threshold of what should get funded and what should not. It is absolutely inappropriate for that purpose."¹²⁹

Moreover, as Southern California Gas Company (SoCalGas), SCE, and SDG&E explain in their joint rebuttal testimony, TURN's proposal is inconsistent with more than a decade of Commission precedent.¹³⁰ As these parties explain:

[T]he Commission in its decisions consistently recognizes that RSE calculations are one factor to help evaluate the relative risk-reduction value of various mitigation activities, but are not intended to serve as the sole, definitive basis for making safety and reliability investment decisions. As such, TURN's assertion that RSE calculations should establish the singular basis upon which to justify PG&E's proposed safety and reliability program expenditures is inappropriate and should not be adopted by the Commission as the policy of the State.¹³¹

SoCalGas, SCE, and SDG&E's joint rebuttal testimony provides additional background on Commission precedent that demonstrates that RSEs are meant to be used for informing the prioritization of investments within a particular risk area, not as the singular basis for determining whether to authorize cost recovery in a GRC.¹³²

Issues related to MAVF and RSE methodology, and the use of benefit-cost ratios for utility risk management, are actively being considered as part of the RDF OIR. Not only PG&E but also SoCalGas, SCE, and SDG&E believe that the RDF OIR is the appropriate forum to address these issues. As SoCalGas, SCE, and SDG&E note, "[a]n issue of such statewide

¹²⁸ See Tr. Vol. 4, 690:14-25, PG&E/Oum; PGE-26, p. YO-1, lines 9-10 (Oum Statement of Qualifications).

¹²⁹ See Tr. Vol. 4, 683:22 to 684:1, PG&E/Singh.

¹³⁰ SoCalGas/SDG&E/SCE-1, p. 2, line 22 to p. 5, line 14.

¹³¹ SoCalGas/SDG&E/SCE-1, p. 5, lines 8-14.

¹³² SoCalGas/SDG&E/SCE-1, p. 2, line 22 to p. 5, line 14.

importance should be discussed and decided in a broad rulemaking, where the interests of all stakeholders can be effectively and efficiently considered, and not in a utility-specific ratemaking proceeding.”¹³³ SoCalGas, SCE, and SDG&E note the Commission has previously recognized the need to address technical aspects of risk-informed decision making framework in the S-MAP rather than in GRC proceedings.¹³⁴

On August 8, 2022, the Commission issued a ruling in the RDF OIR providing the SPD Staff Proposal for comment.¹³⁵ The SPD Staff Proposal identifies weaknesses in the existing MAVF and RSE methodology including the fact that “MAVF’s dimensionless risk scores and risk spend efficiency (RSE) values, intended to assist with Commission decision-making on utility proposed safety mitigations, are poorly understood and offer little guidance in determining the cost-efficiency of proposed investments for the Commission.”¹³⁶ SPD Staff recommends adopting a new approach that would “adopt[] a dollar valuation of risk attributes, which leads to a cost-benefit approach, to replace the MAVF in the RDF.”¹³⁷ The approach outlined by SPD Staff has some similarities to TURN’s benefit-cost proposal here, but differs from it in some critical ways. In particular, the SPD Staff Proposal contemplates that utilities will continue to have the flexibility to use a non-linear scaling function to capture their risk preferences.¹³⁸ In addition, the SPD Staff Proposal identifies several areas where the IOUs have requested the development of additional guidance for the implementation of a benefit-cost approach, including how to capture risk preferences (such as PG&E’s approach to catastrophic risk), model

¹³³ SoCalGas/SDG&E/SCE-1, p. 1, lines 21-23.

¹³⁴ SoCalGas/SDG&E/SCE-1, p. 8, line 24 to p. 9, line 14 (“For example, in Track 1 of SCE’s GRC, the Commission deferred certain of intervenors’ risk-informed decision-making recommendations to S-MAP.”)

¹³⁵ PG&E-29. The SPD Staff Proposal is Attachment A to the Commission ruling.

¹³⁶ PG&E-29, Attachment A, p. i.

¹³⁷ PG&E-29, Attachment A, p. ii.

¹³⁸ PG&E-29, Attachment A, p. 9.

uncertainty (probabilistic ranges), and acceptable risk levels (risk tolerance).¹³⁹ SPD Staff notes that they will continue to facilitate technical working group sessions to discuss these and other emergent topics.¹⁴⁰

Importantly, SPD Staff recognizes that moving to a cost-benefit approach will require modifications to the existing S-MAP framework. The SPD Staff Proposal includes a red-line of the S-MAP Settlement Agreement to show what changes will be necessary to implement its proposal.¹⁴¹ Given that the cost-benefit approach outlined by SPD Staff is not part of the existing S-MAP framework, it would be inappropriate to require PG&E to adopt a cost-benefit approach in our 2023 GRC, which has been ongoing since 2021 and which relies on a risk management methodology developed as part of the 2020 RAMP. In recognition of this, the SPD Staff Proposal notes that “Staff do not expect these recommendations will be implemented retroactively into already filed RAMP applications or General Rate Cases.”¹⁴² Instead SPD Staff proposes that its Phase II recommendations be required beginning with PG&E’s 2024 RAMP.¹⁴³

The SPD Staff Proposal also emphasizes that even if (and when) the new benefit-cost ratio approach SPD Staff is recommending is ultimately adopted, it should not be used in a prescriptive manner:

The benefit-cost ratios are not intended to be the sole determinant for decisions made by the Commission on proposed investments by the IOUs; rather, the benefit-cost ratios are expected to serve as a more helpful input for decision-making that the current RSE values.¹⁴⁴

¹³⁹ PG&E-29, Attachment A, p. 27.

¹⁴⁰ PG&E-29, Attachment A, p. 27.

¹⁴¹ PG&E-29, Attachment B.

¹⁴² PG&E-29, Attachment A, p. v.

¹⁴³ PG&E-29, Attachment A, p. v.

¹⁴⁴ PG&E-29, Attachment A, pp. ii-iii (emphasis in original).

Finally, based on its flawed benefit-cost ratio analysis and its narrow focus on RSE scores, TURN recommends sharply curtailing or eliminating existing programs that are critical for reducing risk and ensuring the safety of customers and communities. For instance, TURN recommends a 94 percent reduction to PG&E's forecast for system hardening for the 2023 GRC period.¹⁴⁵ As noted by SoCalGas, SCE, and SDG&E, this recommendation runs counter to California's and the Commission's public policy in favor of reducing wildfire risk as embodied in Senate Bill 901 – which mandates that utilities construct, maintain, and operate their systems in a manner that will minimize the catastrophic risk of wildfire – and AB 1054 – which requires utilities to reduce the risk of catastrophic wildfires through additional system hardening.¹⁴⁶ PG&E addresses the merits of each program that TURN proposes to eliminate in the applicable sections of this brief. At a high level, however, TURN asks the Commission, customers and communities to gamble on an analysis that is flawed, unproven and, as SPD Staff explains, was never intended as the sole determinant for investment decisions.

¹⁴⁵ Calculated as: \$9,979 million (PG&E's 2023-2026 undergrounding forecast) - \$9,365 million (TURN's recommended 2023-2026 undergrounding reduction) = \$613 million. $(\$9,979 - \$613) / \$9,979 = 94\%$. PG&E's 2023-2026 undergrounding forecast: PG&E-04, p. 4.3-51, Table 4.3-11, lines 4 and 7. TURN's recommended 2023-2026 undergrounding reduction: PG&E-17, WP 4.3-1. TURN's recommendations are presented as recommended funding levels as opposed to recommended reductions. PG&E has calculated the recommended reduction by subtracting Parties' recommended funding level for system hardening underground from PG&E's forecast. PG&E's forecast amount includes both the 10K underground program and Community Rebuild.

¹⁴⁶ SoCalGas/SDG&E/SCE-1, p. 5, line 24 to p. 6, line 18 (citing PUC Section 8386 (Senate Bill 901) and AB 1054).

2.3.2 The Commission Should Not Reject Funding For Gas Safety Programs Due To Their Low RSEs

TURN recommends that the Commission reject funding for seven gas safety programs simply because they have low RSEs.¹⁴⁷ For example, with respect to PG&E's Gas Distribution Over Pressure Protection Program, TURN recommends that "[b]ecause the RSE information in this case shows that the value of the risk reduction from PG&E's proposed work would be minimal compared to the program's costs, the Commission should reject PG&E's requested funding for this program."¹⁴⁸ TURN also recommends drastically reducing other gas safety programs based solely on low RSEs.¹⁴⁹

The Commission should not adopt TURN's recommendation. As explained above in Section 2.3.1, TURN's RSE score and benefit-cost ratio analysis is seriously flawed, inconsistent with Commission precedent, and uses RSE scores for a purpose that was never intended. Prudent risk-based -decision making- must include a wide variety of considerations rather than being based on a single summary statistic (the RSE) as TURN recommends.¹⁵⁰ The Gas risk control and risk mitigation programs proposed for funding in this GRC are based on a series of prioritization investment decision meetings where proposed programs were evaluated based on contribution to risk reduction, code compliance and reasonableness.¹⁵¹ Furthermore, the

¹⁴⁷ The gas risk mitigation programs that TURN proposes to eliminate on the basis of a low RSE score include: Gas Transmission Vintage Pipe Replacement (TURN-02, p. 52, lines 17-18); Gas Transmission Shallow and Exposed Pipe mitigation program (TURN-02, p. 108, lines 5-7); Gas Distribution Over Pressure Protection program (TURN-02, p. 113, lines 13-15); Gas Transmission Over Pressure Protection program (TURN-02, p. 116, lines 7-9); Gas Distribution High Pressure Regulator (HPR) replacement program (TURN-02, p. 119, lines 1-3); Gas Distribution Regulator Station Monitoring (SCADA) program (TURN-02, p. 124, lines 5-7); and Gas Transmission SCADA Visibility program (TURN-02, p.127, lines 1-3).

¹⁴⁸ TURN-02, p. 113, lines 13-15.

¹⁴⁹ For example, TURN proposes significantly reducing upgrades to facilitate in-line inspections of gas transmission pipelines (TURN-04, p. 11, lines 5-21).

¹⁵⁰ This is particularly true when the summary statistic being proposed is untested and the precision of the summary statistic is unknown as is the case with TURN's proposal.

¹⁵¹ PG&E-03, p. 2-20, line 22 to p. 2-22, line 24.

S-MAP Settlement Agreement¹⁵² states, and TURN itself recognizes,¹⁵³ that RSEs are not meant to be the sole determining factor regarding whether risk control or risk mitigation programs should be selected for funding. PG&E provides further detail about the justifications for our Gas Transmission and Gas Distribution mitigations in our rebuttal testimony for EORM¹⁵⁴ and for Gas Operations.¹⁵⁵ These issues are also discussed in detail in Section 3 of this brief.¹⁵⁶

2.3.3 The Commission Should Not Order PG&E To Calculate RSEs For All MAT Codes In Our Next GRC

Cal Advocates recommends that the Commission “require PG&E for all future GRC filings to provide more granular RSEs at the individual MAT code program”¹⁵⁷ noting that having the same RSE across multiple MATs grouped within a program code “makes it impossible to differentiate if one MAT code program is cost effectively reducing risk, whereas another program within the same risk mitigation code is not.”¹⁵⁸

Cal Advocates’ recommendation should not be adopted. In PG&E’s 2020 RAMP and 2023 GRC filings, RSEs are computed at the program (mitigation or control) level. For Electric Distribution and Gas Operations programs, some programs are comprised of multiple MATs. Each MAT within that program has the same RSE value. MATs are an accounting code that underlies PG&E’s MWCs and is used by PG&E to further segregate related work types. For

¹⁵² D.18-12-014, Attachment A, Appendix A, p. A-14, No. 26.

¹⁵³ TURN-02, p. 46, lines 9-10.

¹⁵⁴ PG&E-15-E, p. 1-16, lines 1-20.

¹⁵⁵ PG&E-16-E, Ch. 6, Section C.3.

¹⁵⁶ The operational justifications for the programs that TURN recommends cancelling based on RSE scores are discussed in Sections 3.4.5 (Shallow and Exposed Pipe program), 3.5.3 (GD and GT OPP programs), 3.5.4 (HPR program), 3.10.5 (GD SCADA), and 3.10.6 (GT SCADA).

¹⁵⁷ CALPA-06, p. 27, lines 22-24.

¹⁵⁸ CALPA-06, p. 27, lines 17-19.

example, MWC 2A (Electric Overhead Maintenance) is segregated into several, related MATs such as 2AA (Overhead Notifications), 2AB (Bird Safe Notifications), 2AC (Bird Retrofits Notifications), etc. The MATs were established and are used to track costs and units of work and not as a method for tracking risk mitigations or controls.

It is not feasible to compute RSEs for every MAT with a reasonable level of accuracy. It may be possible to compute MAT-level risk reduction tailored to the specific work the MAT supports but the farther that work is away from direct intervention in a system (e.g., replacing assets, installing engineered barriers between the public and a hazard), the more challenging and abstract, and less useful, that calculation becomes. MATs used to track testing costs are a prime example of MATs for which computing a stand-alone RSE is quite difficult. Level4Ventures, a consulting firm contracted by CPUC staff to evaluate IOUs' risk spend efficiency modeling, describes this challenge as follows: "Many mitigations involve testing, for example In Line Inspection (ILI) or pressure testing of Gas Transmission Pipe. The testing, which may be costly itself, has no RSE unless you account for the option to repair the asset in the event that- the test identifies a problem such as a corroded or cracked pipe."¹⁵⁹ This issue is precisely why GRC program codes often include a bundle of MATs so that information gathering plus the work executed based on that information is considered together when the program is specified and risk reduction is calculated.¹⁶⁰ The S-MAP Settlement Agreement does not require IOUs to calculate RSEs for all MATs; it recognizes that certain programs, such as administrative and general programs and work requested by others, by their nature do not require an RSE.¹⁶¹

¹⁵⁹ R.20-07-013, Risk Spend Efficiency Assessment, Deliverable 2.1: IOU Baseline Assessment (Rev. Feb. 15, 2022), p. 20.

¹⁶⁰ PG&E-15-E, p. 1-42, lines 14-17.

¹⁶¹ D.18-12-014, Attachment A, Appendix A, pp. A-14 to A-17, No. 28, Step 3 Supplemental Analysis in the GRC.

2.4 Safety Policy and Strategy

2.4.1 Everyone And Everything Is Always Safe.

PG&E's safety stand is not just words; it is our way of doing business. The safety of the public, our employees and contractors must come before anything else, all the time, everywhere. This commitment is reflected in every decision, every action, and in our planning and prioritization of work.¹⁶² Our 2023 GRC was planned and prepared with the achievement of the highest level of safety top of mind, as our primary goal.

2.4.2 Workforce Safety Programs

PG&E's opening testimony described our renewed focus on workforce safety over the last decade. PG&E described our engagement of Regional Safety Directors who support the Regional Vice Presidents and the safety programs in each of PG&E five new regions.¹⁶³ PG&E also described our internal safety governance and 2025 Workforce Safety Strategy, which is the next evolution of PG&E's Safety Strategy and includes strategies to address critical risks, transportation safety, contractor safety management, serious injury and fatality management, the Enterprise Corrective Action Program, Health and Safety Management System, Assurance, Occupational Health and Field Safety Operations.¹⁶⁴ PG&E also described how our lines of business lead public safety roles in each of their respective organizations, conduct root cause analyses of safety incidents, and provide oversight of safety.¹⁶⁵ None of the parties disputed or addressed the safety policy strategies discussed in our opening testimony.

2.4.3 Public Safety Programs

Most incremental funding in this proceeding is focused on measures necessary to keep both the public and our workforce safe throughout our large and diverse service area. PG&E has

¹⁶² PG&E-02, p. 2-1, lines 1-17.

¹⁶³ PG&E-02, p. 2-3, line 24 to p. 2-4, line 24.

¹⁶⁴ PG&E-02, p. 2-6, line 14 to p. 2-28, line 4.

¹⁶⁵ PG&E-02, p. 2-28, line 5 to p. 2-31, line 10.

demonstrated in recent years our commitment to invest what is necessary to strengthen our operations. Indeed, through the first quarter of 2022, we had \$4.7 billion of unrecovered wildfire mitigation and catastrophic event related costs accumulated on our balance sheet – costs which address wildfire safety and catastrophic events.¹⁶⁶ However, we cannot continue to overspend our revenue requirement to meet our safety obligations and remain a financially healthy utility.¹⁶⁷

Parties urge the Commission to deny safety programs that they claim are not “cost effective.”¹⁶⁸ But consideration of cost effectiveness -- particularly for wildfire mitigation -- must not only consider the cost of the programs themselves but must also take into account the devastating impact on communities and broader economic losses and harm throughout the economy caused by catastrophic wildfires. In other words, the Commission, PG&E, and stakeholders must consider the economic consequences of inaction.¹⁶⁹

As Dr. Robert Earle’s testimony on behalf of the CUE explains, the question of whether wildfire mitigation is cost effective cannot be considered without studying the enormous toll wildfires are taking on the state:

An estimate of the indirect economic impact of California wildfires in 2018 alone was \$88.6 billion, of which \$42.7 billion were within the state of California. Health costs from wildfires likewise take an enormous toll. For the California 2018 wildfires alone, they are estimated to be \$32.2 billion. Health impacts also disproportionately impact vulnerable communities, bringing environmental justice concerns to both health impacts and economic damages.¹⁷⁰

¹⁶⁶ PG&E-14, p. 3-21, line 20 to p. 3-22, line 2.

¹⁶⁷ PG&E-14, p. 3-21, line 15 to p. 3-22, line 20.

¹⁶⁸ TURN-02; p. 75, AARP-01, p. 27, line 16 to p. 28, line 17. AARP’s witnesses (who appeared on behalf of TURN during four recent IOU GRCs) similarly opposed efforts to reduce the risk of injury and loss of life during hurricanes on the grounds that the safety improvements were not “cost effective.” Tr. Vol. 12, p. 2313:15-2315:6, AARP/Alvarez and Stephens.

¹⁶⁹ Tr. Vol. 4, 545:4-9, PG&E/Peterman.

¹⁷⁰ CUE-01, p. 1, lines 10-15.

While PG&E seeks to prioritize safety, other parties propose deep cuts to safety programs. These cuts, if approved, would put the public at greater risk. PG&E agrees that the cost of PG&E’s activities is an important concern, however, we do not and cannot dismiss public or employee safety risk simply because a problem is difficult or expensive to address.¹⁷¹ The public, our customers, and our employees rely on us to keep them safe. As we discuss below, investing in our gas and electric system to obtain a higher level of safety is legally required and is the right thing to do.

2.4.4 PG&E Operates At High Levels Of Safety Consistent With Legal And Regulatory Requirements And Commission Oversight

Our pursuit of best safety practices, as described in our testimony, extends to all areas of our operations to drive top safety performance. As discussed below, some of this pursuit of safety is also required to comply with state and federal laws.

The California Legislature adopted statutes that require utilities to follow “*best* practices for wildfire reduction.”¹⁷² Indeed, both Senate Bill (Sen. Bill or SB) 901 and Assembly Bill (AB) 1054 require PG&E to “construct, maintain, and operate its electrical lines and equipment in a manner that will *minimize* the risk of catastrophic wildfire posed by those electrical lines and equipment.”¹⁷³ The California Legislature created the Office of Energy Infrastructure Safety (Energy Safety) effective July 1, 2021 to ensure that electrical utilities are taking effective actions to reduce utility caused wildfires.¹⁷⁴ To reduce wildfire risks, PG&E must take actions “to ensure its system will achieve the *highest* level of safety, reliability, and resiliency, and to ensure that its system is prepared for a major event, including hardening and modernizing its

¹⁷¹ See D.19-09-025, p. 73 (the Commission’s standard for approval of expenditures is not whether they are “expensive” but “whether the costs are just and reasonable.”)

¹⁷² Assem. Bill No. 1054 (2019-2020 Reg. Sess.) § 2(e).

¹⁷³ Pub. Util. Code, § 8386(a) (emphasis added).

¹⁷⁴ Govt. Code, § 15475.1.

infrastructure with improved engineering, system design, standards, equipment, and facilities such as *undergrounding, insulating of distribution wires and replacing poles*”¹⁷⁵

PG&E, in our function as a gas utility, is mandated to follow “best practices in the gas industry” under California law and “meet or exceed” federal gas pipeline safety standards.¹⁷⁶ Gas utilities and independent storage providers must comply with all safety regulations established by national regulators such as the PHMSA and state regulators such as the CalGEM.

The Commission also supports PG&E’s goals to improve our safety performance through its oversight of PG&E’s gas and electric system. The Safety and Enforcement Division (SED) promotes utility safety by performing gas and electric safety audits and conducting incident investigations. SED experts provide leadership and technical expertise related to major threats to utility safety, such as wildfires, natural gas pipeline risks, and gas storage leaks. In addition, the Safety Policy Division provides advisory support to the Commission on policy and regulation to advance delivery of safe, reliable services by utilities subject to the CPUC’s jurisdiction and oversight. Finally, the Commission reviews and approves utilities’ funding requests for safety programs and activities.

These are just a few examples of the laws, regulations, and regulatory oversight that have informed our safety program proposals in this GRC. Throughout this Opening Brief, we describe the specific laws, regulations, and regulatory requirements that underlie each of the disputed safety programs and demonstrate the need for these programs and the reasonableness of our expense and/or capital expenditure forecasts.

2.4.5 Parties Propose Deep Spending Cuts In Safety Program Funding

Our application, testimony, and workpapers provide extensive descriptions of the public and workforce safety programs that we are proposing for the rate case period. Each program is

¹⁷⁵ Pub. Util. Code, § 8386(c) (14) (emphasis added).

¹⁷⁶ Pub. Util. Code, §§ 961(c), 961(d)(9).

described in detail, including the safety issue(s) being addressed, relevant regulatory and legal requirements, and the basis for our expense and/or capital expenditure forecast. Throughout this Opening Brief, we will address each of the disputed safety programs and demonstrate that our forecasts and proposals are reasonable, prudent, and in the interest of the customers and communities that we serve. Below, we provide some high-level examples of the types of safety program cuts that parties are recommending. These examples, as well as numerous other safety programs, are addressed in detail in the remainder of our Opening Brief.

2.4.5.1 Party Proposals To Reduce Electric Safety Spending

Despite the devastating impact of wildfires in California, parties suggest that we step back and do less to reduce the risk of potential wildfire ignitions. Specifically, Cal Advocates, TURN, AARP, and MGRA propose massive reductions to the scope of our Community Wildfire Safety Program as well as other programs that promote employee and public safety. AARP's witnesses even admitted that they made no effort to determine whether their opposition to wildfire mitigation programs represented the views of AARP or AARP members who reside in California's high fire threat district areas, though they later attempted to take back some of these statements.¹⁷⁷ PG&E has a goal of obtaining the highest level of safety and adopting best safety practices. These parties state that they support safety initiatives, but their recommendations tell a different story.

TURN, for example, acknowledges the prudence of the PG&E's electric system inspection programs, which are foundational to maintaining a safe system, but recommends a nearly 20 percent cut to PG&E's overhead inspection forecast.¹⁷⁸

For electric asset management forecasts, Cal Advocates does not dispute that the planned asset replacement work is important to safety, yet recommends substantial cuts to programs

¹⁷⁷ Tr. Vol. 12, 2297:21 to 2298:5; 2299:8 to 2298:14; 2308:3 to 2308:8, AARP/Alvarez and Stephens.

¹⁷⁸ TURN-09, p. 1, line 15, p. 29, lines 3-4.

important to safety including approximately 70 percent reduction to PG&E's forecasts for: (1) overhead switch replacement program to minimize potential safety issues during switching operations and to improve reliability; and (2) load break (LBOR) switch replacement program to eliminate a safety risk for work crews.¹⁷⁹ Cal Advocates also recommends a nearly 30 percent reduction to PG&E's forecasts for non-wood streetlight replacements, which they characterize inaccurately as "virtually no change."¹⁸⁰ Replacing non-wood poles, however, mitigates a public safety risk of catastrophic streetlight pole failures due to corrosion or damage.¹⁸¹

AARP argues for an approximately 40 percent cut to PG&E's capital forecasts for four network asset management activities in downtown San Francisco and Oakland: (1) network protector relay replacements; (2) network transformer and protector replacements; (3) network Supervisory Control and Data Acquisition (SCADA) safety monitoring project upgrade; and (4) electric distribution undergrounding asset replacements. In the event of an asset failure, there is the potential of catastrophic failures such as manhole explosions/fire and safety risks to employees and the public.¹⁸² In addition, Cal Advocates proposes reducing PG&E's forecast for ceramic post insulators replaced by more than 80 percent in 2023,¹⁸³ which would significantly reduce the risk reduction afforded by this mitigation.

¹⁷⁹ Cal Advocates opposes PG&E's forecast for the Overhead Switches replacement program, which will address safety issues during operations. PG&E-17, p. 13-15; CALPA-06, p. 53, lines 13-18. Cal Advocates also opposes PG&E's forecast for the LBOR Switch replacement program, which will replace switches that pose a safety risk for work crews. PG&E-17, p. 13-21, lines 21-22, CALPA-06, p. 60, lines 4-17.

¹⁸⁰ CALPA-06, p. 43, Table 6-20, p. 43, lines 6-7.

¹⁸¹ PG&E-04, WP 11-54.

¹⁸² AARP-01, p. 44, line 13 to p. 45, line 2; PG&E-17, p. 14-9, lines 9-12.

¹⁸³ CALPA-06, p. 39, Table 6-17.

Still more, Cal Advocates and TURN collectively recommend an approximately 33 percent reduction¹⁸⁴ to PG&E's forecast for pole replacements, which are necessary for PG&E to mitigate wildfire and other safety risks. Finally, as discussed in Section 4.3, each of these intervenors and several others recommend that the Commission deny or delay a decision on PG&E's undergrounding proposal. If adopted, these recommendations would significantly thwart PG&E's efforts to mitigate wildfire risks in HFTD areas.

These proposals, if approved, would put public safety at risk by insufficiently funding our wildfire mitigation efforts needed to make our communities safe.

2.4.5.2 Party Proposals To Cut Gas Safety Programs

While PG&E is laser-focused on wildfire risk mitigation, this focus cannot come at the price of increasing risk PG&E's gas operations. While Cal Advocates and TURN claim to have considered safety in preparing their recommendations, their proposed funding cuts to Gas Operations also tell a different story.

As an example, the Gas Pipeline Replacement Program is one of the core programs PG&E proposes to improve gas safety through the replacement of vintage steel distribution pipe. TURN proposes cutting this program by about 60 percent¹⁸⁵ and Cal Advocates proposes reducing the budget by approximately 25 percent.¹⁸⁶ These parties also seek to drastically reduce the rate of replacement of pre-1985 plastic pipe, which is prone to cracking and early failure when exposed to stress, such as tree roots, differential settlement, or rock impingement.¹⁸⁷ TURN proposes a 66 percent reduction to PG&E's requested funding, which

¹⁸⁴ PG&E-17, p. 12-4, Table 12-2. Cal Advocates recommends a \$31.8 million decrease to PG&E's pole replacement forecasts. CALPA-05, p. 16, Table 05-3. TURN recommends reductions exceeding \$75 million to PG&E's pole replacement forecasts. TURN-09, p. 50, lines 9-14.

¹⁸⁵ TURN-06, p. 25, Table 14.

¹⁸⁶ CALPA-02, p. 12, Table 2-10.

¹⁸⁷ See Section 3.3.4 of this brief.

corresponds to a 66 percent reduction in replacement program scope.¹⁸⁸ Cal Advocates proposes a reduction of more than 25 percent.¹⁸⁹ Collectively, these proposed program cuts by TURN and Cal Advocates, if adopted by the Commission, would result in aging, deteriorating vintage steel pipe and crack -prone pre-1985 plastic pipe remaining in the ground well beyond their expected asset lives, posing a significant safety risk of loss of containment.

TURN also proposes significant cuts to PG&E's gas transmission safety programs such as a 73 percent reduction for the in-line inspection program, the most comprehensive and reliable pipeline integrity program, as well as the complete elimination of PG&E's vintage pipe replacement and shallow and exposed pipe (including water and levee crossing) programs which are critical public safety programs.¹⁹⁰

Finally, on the pretext of low risk scores from the RAMP, TURN proposes to cancel outright critical common-sense safety programs to protect customers from gas over pressure events, and to provide gas system operators with greater ability to detect and respond to anomalous conditions. TURN proposes to defund both the distribution and transmission level Over-Pressure Protection (OPP) programs¹⁹¹ that are designed to install protective devices at gas regulator stations to prevent pressure spikes from migrating downstream to end-use customers and that can result in loss of containment with ignition causing injuries and fatalities, loss of service, and/or equipment damage.¹⁹² Similarly, TURN recommends defunding the gas distribution and transmission SCADA programs¹⁹³ that install devices at various points on the

¹⁸⁸ TURN-06, p. 21, lines 1-2.

¹⁸⁹ CALPA-02, p. 12, Table 2-9.

¹⁹⁰ PG&E-16, p. 5-8, lines 20-21; p. 5-69, lines 1-3; p. 5-73, lines 8-12; TURN-04, p. 21, lines 4-5; p. 52, lines 17-18; TURN-02, p. 108, lines 6-7.

¹⁹¹ TURN-02, p. 136, line 5 to p. 137, line 14.

¹⁹² See Section 3.5.3 of this brief for a full discussion of the operational drivers of the OPP program.

¹⁹³ TURN-02, p. 139, lines 1-2.

gas system to detect conditions that are out of the normal range, sending an alarm to the Gas Control Center that can be investigated and remediated.¹⁹⁴ These and other safety programs TURN proposes to cancel¹⁹⁵ are justified by numerous operational factors and comport with regulations and best industry practices and have previously been approved for funding by the Commission

2.5 Planning, Work Prioritization And Financial Issues

2.5.1 Operating Rhythm

PG&E witness Stephanie Williams sponsored Exhibit PG&E-02, Chapter 3 which describes PG&E's process of developing our risk-informed 2023 GRC forecast.¹⁹⁶ Following the submission of this opening testimony, PG&E submitted testimony in February 2022 that updated certain of PG&E's wildfire mitigation strategies. As a result of this update, 86 percent of the revenue requirement increase over 2022 adopted proposed in this GRC is for work to mitigate risks in our gas and electric operations.¹⁹⁷ Ms. Williams' testimony described PG&E's new framework to run the business entitled the "Operating Rhythm," an integrated enterprise-wide structure focused on planning, performance management and governance through which PG&E monitors operations, compliance and prioritizes spending to address PG&E's highest priorities.¹⁹⁸

Ms. Williams also described PG&E's customer affordability program, which seeks opportunities to obtain savings throughout the organization through: (1) operational

¹⁹⁴ See Sections 3.10.5 and 3.10.6 of this brief for a full discussion of the operational drivers of the Gas Distribution and Gas Transmission SCADA programs.

¹⁹⁵ TURN also proposes cancelling the High Pressure Regulator (HPR) rebuild program that replaces aging and obsolete regulators. TURN-02, p. 138, lines 1-4. The operational drivers for the program are addressed in Section 3.5.4 of this brief.

¹⁹⁶ PG&E-02, p. 3-3, line 11 to p. 3-5, line 2.

¹⁹⁷ PG&E-14, p. 3-24, lines 8-10; see also TURN-108, PG&E response to Data Request TURN_215-Q2, Attach. 1.

¹⁹⁸ PG&E-02, p. 3-1 p. 20 to 3-3, line 3.

improvements, (2) investment optimization, and (3) transactional.¹⁹⁹ As Ms. Williams explained:

Operational Improvements result in reduction in the per unit cost of work through work planning & bundling, resource allocation, strategic sourcing negotiations and other process improvements. Investment Optimization savings are the result of right sizing investments relative to the value created (primarily risk reduction) through repair vs replace decisions, policy changes, work method enhancements and asset strategy refinement. Transactional savings are comprised of efforts such as selling real estate, renegotiating our power purchase agreements, and selling excess renewable energy credits. Savings will be realized at the time each transaction closes.²⁰⁰

Ms. Williams also testified, “[t]he customer affordability program will be informed by benchmarking, system performance, operational performance, and investment optimization modeling.”²⁰¹ As part of continuing improvements, the Customer Affordability Program will continue to pursue efficiency opportunities in the 2023 GRC to benefit customers.

2.5.2 Deferred Work And Spending Accountability Issues

2.5.2.1 PG&E Has An Obligation To Reprioritize Funding To Provide Safe And Reliable Service

PG&E is expected to manage the funds approved in the GRC reasonably, including by reprioritizing activities as necessary, consistent with our responsibility to provide safe and reliable service. The Commission requires this:

It is generally recognized that when a utility files a GRC, expenditure estimates are based on plans and preliminary budgets developed at least two years in advance of when they will actually be incurred. When the utility finalizes its budget just prior to the year when costs will be incurred or adjusts the budget during the year, new programs or projects may come up, others may be cancelled, and there may be reprioritization. This process is expected and is necessary for the utility to manage its operations in a safe and reliable manner.²⁰²

¹⁹⁹ PG&E-02, p. 3-5, lines 15-17.

²⁰⁰ PG&E-02, p. 3-5, lines 20-28.

²⁰¹ PG&E-02, p. 3-5, lines 17-19.

²⁰² D.11-05-018, p. 27.

PG&E uses both our enterprise-wide planning and budgeting process and our governance procedures at the LOB and enterprise levels to manage this process.²⁰³ PG&E uses an enterprise framework to work with the various PG&E lines of business “to prioritize the work that we feel is most critical in addressing safety and risk at the time.”²⁰⁴

PG&E’s Senior Leadership team through the framework of the Operating Rhythm as augmented by the Lean Operating System focuses on performance indicators, decision making, governance and process management. This process is designed to ensure that PG&E allocates resources appropriately to maintain safe and reliable service. From a spending perspective, LOBs formally identify and communicate emerging spending needs to the enterprise-wide planning and budgeting process that they are not able to internally prioritize, including emerging needs related to safety, compliance, and reliability work. The Senior Leadership Team determines whether and how to reprioritize activities across the enterprise to address those needs and reflects those decisions in the LOB operating budgets.²⁰⁵

Reprioritizing funding to address emerging safety and reliability needs can also occur after annual operating budgets are set. When possible and appropriate, emerging issues that must be addressed during a planning year are managed within the LOB in various ways, including by identifying efficiency opportunities or adjusting the LOB’s work plan to accommodate emerging issues. Emerging issues that cannot be solved within an LOB are identified, communicated, and solved through the enterprise-wide planning and budgeting process and Senior Leadership Team review and approval.²⁰⁶

²⁰³ PG&E-02, p. 3-6, lines 3-7.

²⁰⁴ Tr. Vol 4., p. 722:13-18, PG&E/Williams.

²⁰⁵ PG&E-02, p. 3-6, lines 13-26.

²⁰⁶ PG&E-02, p. 3-7, lines 1-9.

Reprioritization necessarily means that projects for which funding was originally adopted in a GRC may be delayed or canceled. This is an accepted part of the planning and operational process between GRCs, as the Commission has acknowledged:

We conclude that this is not deferred maintenance in the sense we discussed previously. The work was not deferred to improve the utility's financial position. *We do not intend to push utilities to spend the earmarked maintenance dollars simply to avoid risk of disallowance in a future proceeding.* Because we hold the utility accountable to provide safe, reliable and efficient service, the utility should be able to move maintenance dollars from one account to another for the reasons provided in this case

In summary, we should note that the issue in this instance is not deferred maintenance; rather, it is whether the utility should have the flexibility to shift earmarked funds if it is in the ratepayers' interest to do so. *We conclude that if the utility has a valid reason based on economic or other considerations, then it should have the flexibility. This is simply prudent management.*²⁰⁷

In the Commission's decision in PG&E's 2015 GT&S rate case, it reaffirmed that "PG&E's forecast costs are not unreasonable and subject to ratemaking disallowance simply because its management delayed or deferred work."²⁰⁸

The Commission should not include overly-prescriptive rules that would have the inadvertent impact of reducing PG&E's ability to shift funds to the most urgent projects or provide a disincentive to cost reduction as it would run counter to customers' interests in having safe, reliable and affordable service.

2.5.2.2 Deferred Work Analysis And Showing In PG&E's 2023 GRC

PG&E's testimony regarding work conducted during the 2020 GRC period complied with Section 5.2 of the 2020 GRC Settlement "Deferred Work Principles" (hereinafter Deferred Work Settlement or DWS).²⁰⁹ The DWS defines "deferred work" as any work proposed in the 2020 GRC or 2019 GT&S rate case where: (1) the work was requested and authorized based on

²⁰⁷ D.11-05-018, p. 27 (quoting D.83-12-068, 14 CPUC2d 15, 146, and D.94-12-068, 16 CPUC2d 721, 782) ((emphasis added)).

²⁰⁸ D.16-06-056, p. 22.

²⁰⁹ PG&E-02, p. 3-7, lines 11-13.

representations that it was needed to provide safe and reliable service; (2) PG&E did not perform all of the authorized and funded work, as measured by authorized (explicit or imputed) units of work; and (3) PG&E continues to represent that the curtailed work is necessary to provide safe and reliable service.²¹⁰

The DWS lists six principles that were reflected in prior GRC decisions. The 2020 GRC Settlement requires that for all work meeting the definition of deferred work “PG&E’s direct showing in support of the reasonableness of its forecast in the rate case shall provide at a minimum, a demonstration of how the specific funding request is consistent with the principles.”²¹¹

The DWS further requires that for any work that meets the deferred work conditions, PG&E’s direct showing in support of the reasonableness of our forecast in the rate case explain:

- a. Why the authorized work was not performed in the time forecasted;
- b. Whether the deferral of the authorized work resulted in lower than authorized spending for the authorized work;
- c. How the funding was reallocated and whether such reallocation related to the provision of safe and reliable service; and
- d. To the extent that authorized funding for safety related work was used for other purposes, the reasonableness of the alternative work for the purpose of evaluating the appropriateness of the new funding request.²¹²

In preparation for our filing and testimony in this proceeding, our LOBs conducted an analysis of the work forecast in the 2020 GRC and the 2019 GT&S rate case expected to be completed between 2020 and 2022 (2019 and 2022 for GT&S work) to analyze whether there is any work forecasted in this GRC that could be categorized as “deferred work.” The results of the

²¹⁰ D.20-12-005, p. 37.

²¹¹ D.20-12-005, p. 37; PG&E-02, p. 3-8, line 6 to p. 3-13, line 11, Section F.3 sets forth the six principles, and describes how PG&E’s reprioritization decisions over the last rate case period are consistent with the principles.

²¹² PG&E-15, p. 3-2, lines 13-24.

analysis are summarized in opening testimony.²¹³ In addition, for all identified deferred work, we demonstrated consistency of our reprioritization decisions with the six deferred work principles.²¹⁴

No party took issue with PG&E's identified deferred work presented in testimony, or recommended any disallowance based on the identified deferred work.²¹⁵ However, in response to PG&E's deferred work testimony, TURN recommended that the DWS requirements be continued in the next rate case²¹⁶ and that PG&E be required to demonstrate that any reprioritization of funds from work meeting the deferred work criteria be supported by RSE scores.²¹⁷ TURN's recommendations should be rejected as discussed below.

2.5.2.3 The Deferred Work Settlement Should Be Discontinued

TURN claims that "DWS has promoted increased accountability for the efficient use of ratepayer funds."²¹⁸ The DWS is not necessary, however, to ensure that PG&E is accountable for managing our GRC-authorized- funding to ensure a safe and reliable system. Accountability is already assured by existing Commission requirements to identify deferred work in rate cases, and by extensive annual risk spending accountability reporting (RSAR) requirements that were recently modified to include analysis of spending and variances from authorized spending over the whole GRC cycle.

First, PG&E is already required to address deferred work in future GRCs. As part of our GRC showing, where it is requesting funding for safety and reliability work, and a forecast for

²¹³ PG&E-02, pp. 3-14 to 3-23, Table 3-1.

²¹⁴ PG&E-15, p. 3-3 lines 3-6.

²¹⁵ TURN recommended disallowances for two of PG&E's 2023 gas operations funding requests that were not identified in PG&E-02, Table 3-1. These are the Los Medanos and Tionesta compressor station projects and are addressed in Sections 3.5.5 and 3.5.6 of this brief.

²¹⁶ TURN-19, p. 22, lines 18-19.

²¹⁷ TURN-19, p. 26, lines 13-15.

²¹⁸ TURN-19, p. 22, line 26 to p. 23, line 2.

funding the same work was adopted in the previous GRC decision but the work was not performed, it must demonstrate the reasonableness of our request. In D.11-05-018, the Commission said, “[w]hile we reaffirm that it is utility management’s prerogative and responsibility to provide safe and reliable service by reprioritizing and deferring activities as necessary, the Commission must be assured that the process is reasonable.”²¹⁹

Second, due to ongoing reporting requirements, PG&E is already accountable for the efficient use of ratepayer funds. PG&E has a continuing obligation to report to the Commission when adopted capital or expense funding for maintenance, safety or reliability was redirected by PG&E.²²⁰ D.19-04-020 requires the IOUs to explain any significant variances in adopted and actual spending on maintenance, safety or reliability in their GRC, through detailed annual RSAR. The Commission noted that the RSAR “will provide for improved accountability of utility safety, reliability and maintenance spending.”²²¹ The IOUs’ reporting requirements for work that was “canceled, deferred or expanded” are also defined in that Decision.²²² The RSAR must be filed annually in the IOUs’ GRCs and the IOUs most recent RAMP proceeding.²²³ D.19-04-020 provides the Energy Division and interested parties, including TURN, an opportunity to review and comment on the IOU’s annual reports.²²⁴

Moreover, in D.22-10-002, the Commission adopted the following additional RSAR reporting requirements that effectively supersede the DWS requirements:

IOUs shall track programs over a full GRC cycle in the RSAR. Each program shall include the cumulative GRC imputed costs, imputed costs to date, actual

²¹⁹ D.11-05-018, p. 29.

²²⁰ Pub. Util. Code, § 591.

²²¹ D.19-04-020, p. 38. Beginning with the 2023 RSAR, PG&E’s RSAR scope will expand to include GT&S data.

²²² D.19-04-020, p. 39-43 and Attachment 2.

²²³ D.19-04-020, pp. 64-65, Ordering Paragraph (OP) 8.

²²⁴ D.19-04-020, pp. 64-65, OP 8.

costs by year, cost to date, and variance to date. IOUs shall provide a statement regarding the anticipated completion status for each line item as to whether the program is anticipated to be completed during the GRC cycle. For the last year of the GRC cycle, the completion status will summarize the entire GRC cycle and discuss any deferred or cancelled scope.²²⁵

As a result, in our future RSARs, PG&E will identify variances for our GRC-authorized safety and reliability programs and address the “completion status” for the reporting year and GRC cycle. These reports will provide the Commission and parties with more than sufficient information to identify and address deferred work from the prior GRC period without PG&E being required to provide a duplicate analysis in the GRC.²²⁶

TURN also claims that the “DWS has averted disputes about the principles applicable to deferred and reprioritized work.”²²⁷ However, as discussed above, Commission precedent already addresses IOUs’ obligations with respect to deferred work and reprioritized spending. The “Principles for Deferred Work” in the DWS are derived from applicable precedent in Commission decisions,²²⁸ and these decisions continue to bind PG&E and would guide any showing made in future GRC testimony where PG&E seeks and obtains funding in the prior GRC for a specific project, the project is deferred, and PG&E requests the Commission to adopt a forecast for the same project.

For these reasons the DWS should be discontinued. Commission precedent regarding deferred work, and spending accountability reporting requirements coupled with Commission oversight provide a sufficient framework to allow deferred work to be identified and addressed

²²⁵ D.22-10-002, Appendix A, p. A3, Requirement 23, adopted in OP 1.

²²⁶ Additionally, PG&E currently files a semi-annual Gas Transmission and Storage Compliance Report that provides information about our transmission pipeline work including all costs recorded to these programs. D.19-09-025, pp. 11-12, and p. 334, OP 83. However, reporting on these programs will be merged with RSAR starting in 2023. D. 22-10-002, p. 56, OP 3.

²²⁷ TURN-19, p. 23, lines 11-12.

²²⁸ D.17-05-013, p. 187.

by the Commission. This approach will also put PG&E on the same footing as the other IOUs who are not subject to the Deferred Work Settlement.²²⁹

2.5.2.4 The Deferred Work Settlement Should Not Be Revised To Require Reprioritization Decisions Be Justified Based On RSE Scores

In addition to its proposal to continue the DWS, TURN recommends that in the future, DWS testimony should include RSE scores to justify any reprioritization of funding.²³⁰ If the DWS is continued into the next rate case, which for the reasons explained above in Section 2.5.2.3 it should not be, TURN's proposal should be rejected.

First, adjusting the DWS to call out RSE scores specifically as the reason to justify reprioritization decisions gives undue weight to RSE analyses which should instead be one data point to be considered along with operational requirements, prudent utility asset management practices, compliance requirements and other factors. As PG&E witness Sumeet Singh explained in his rebuttal testimony:

Prudent risk-based decision-making must include a wide variety of considerations. . . . RSEs are not meant to be the sole determining factor regarding whether risk control or risk mitigation programs should be selected for funding.²³¹

To add to the DWS TURN's proposed approach of making funding decisions based on RSE scores would undermine safety and reliability and limit utility flexibility to manage its portfolio of work.

Furthermore, as discussed in Section 2.1 above, the RAMP modelling methodology on which RSEs are based is still relatively early in its development and will continue to evolve in the ongoing Risk-Based Decision-Making Framework OIR.²³² RSEs have not reached the level

²²⁹ PG&E-15, p. 3-6, lines 2-7.

²³⁰ TURN-19, p. 25, lines 8-9.

²³¹ PG&E-15-E, p. 1-15, lines 3-14.

²³² PG&E-15-E, p. 1-4, lines 6-16.

of maturity where they could reasonably be used for reprioritization purposes.²³³ For all these reasons, it is premature to insert language into the DWS that would require that reprioritization decisions be “supported by RSE scores.”

If the Commission believes, however, that a reference to RSE scores in the DWS is appropriate, PG&E recommends that TURN’s proposed wording²³⁴ be revised as follows:

To the extent that authorized funding for safety related work was used for other purposes, PG&E’s showing in support of its forecast for additional funding for the curtailed work shall include a demonstration of the reasonableness of the alternative work, **including a discussion of** ~~supported by~~ RSE scores calculated in accordance with Commission requirements, for the purpose of evaluating the appropriateness of the new funding request.

2.5.3 PG&E’s Financial Health

The Commission has previously acknowledged the importance of the GRC in maintaining the overall financial health of the utility, which will allow it to raise capital to the benefit of utility customers. For example, in the 2014 GRC, the Commission stated:

For purposes of setting test year and attrition year revenue requirements in this proceeding, we find it sufficient to acknowledge the importance of the GRC process as a tool in supporting PG&E’s ongoing ability to provide safe and reliable service while affording a reasonable opportunity to earn its rate of return and thereby attract capital to fund its infrastructure needs.²³⁵

Despite TURN’s various proposals to underfund the utility’s operations, even TURN concedes that “[a]dopted revenue requirements and the disposition of disputed ratemaking issues should be consistent with the goal of supporting PG&E’s ability to provide safe and reliable service *while maintaining its financial health and ability to raise capital.*”²³⁶ Governor Newsom, in his June 21, 2019 official report on catastrophic wildfires, explained that stabilizing the financial health of California’s utilities is essential to enable them “to provide safe,

²³³ PG&E-15-E, p. 1-10, line 20 to p. 1-11, line 9.

²³⁴ TURN-19, p. 27, lines 3-7.

²³⁵ D.14-08-032, p. 645.

²³⁶ D.20-12-005, p. 325; TURN-19, p. 22, line 3-6 (emphasis added).

affordable and reliable energy, ensure fair compensation for wildfire victims, and protect ratepayers from massive rate spikes.”²³⁷ This is consistent with California legislative findings that the health of the utilities is important for customers because the utilities must “have access to capital at reasonable costs to make safety investments.”²³⁸

The Commission should reject parties’ proposals that would result in operations being underfunded and/or reduce our ability to raise sufficient capital to fund operations. While PG&E spends what is necessary for safe and reliable operations, overspending the revenue requirement to fund PG&E’s operations -- as parties continue to urge here -- damages PG&E’s financial health.²³⁹

There are three types of proposals in this case that threaten the utility’s financial health: (1) proposals to require the utility to carry excessively high balances in memorandum accounts without a revenue requirement; (2) proposals to underfund reasonable and necessary utility operations by requiring “shareholder contributions”; and (3) TURN’s proposal to finance capital investments in wildfire mitigation at the cost of debt. As discussed below, in reviewing these arguments against funding normal utility operations, the Commission must consider their adverse impact on PG&E’s financial health.

2.5.3.1 The Commission Should Not Delay Cost Recovery For Appropriate Forecast Business Expenses.

Cal Advocates and TURN make various proposals to remove an aggregate amount of approximately \$2.1 billion of capital expenditures forecasts for the period 2021 to 2023 and approximately \$44 million of O&M expense from the 2023 test year forecast. Instead, they

²³⁷ Governor Newsom’s Strike Force Progress Report on Catastrophic Wildfires, Climate Change and Our Energy Future (June 21, 2019), p. 7, <<https://www.gov.ca.gov/wp-content/uploads/2019/06/Strike-Force-Progress-Report.pdf>> (as of Oct. 21, 2022).

²³⁸ Assem. Bill No. 1054 (2019-2020 Reg. Sess.) § 2(c).

²³⁹ Tr. Vol. 4, 725:7-23, PG&E/Williams.

would have PG&E track those costs on a recorded basis through memorandum accounts and/or seek to recover those costs in future applications.²⁴⁰

Cal Advocates' memorandum account proposals include business expenses that can reasonably be forecast and approved as part of the 2023 revenue requirement. Such expenses include, but are not limited to, the transition to the Oakland Headquarters approved by the Commission in D.21-08-027, emergency generation equipment acquired in 2021-2022, the entire Community Rebuild Program forecast, and pole replacements costs.²⁴¹ TURN recommends the entire costs of PG&E's billing system upgrade project be re-litigated in another application proceeding.²⁴²

Excessive use of memorandum accounts and cost recovery deferrals is poor policy that ultimately increases costs for customers. Better policy would support the utility's financial health and other regulatory principles (such as intergenerational equity) that are intended to ensure that customer rates are just and reasonable by approving cost recovery of these amounts on a forecast basis in this GRC. Memorandum accounts are generally appropriate for costs that cannot be reasonably forecasted in a GRC due to timing or significant uncertainties that render a forecast unreliable.²⁴³ Memorandum accounts are not appropriate where ". . . costs can be forecast with reasonable accuracy and included in rate case applications."²⁴⁴ The costs for which TURN and Cal Advocates are seeking memorandum account treatment are typical of the costs that are routinely forecasted in GRCs.

Excessive use of memorandum accounts without current rate recovery diminishes the utility's financial health by deferring the cash collections needed to service the debt used to

²⁴⁰ PG&E-14, p. 3-2, lines 12-17.

²⁴¹ PG&E-14, p. 3-2, line 17 to p. 3-4 line 4.

²⁴² PG&E-14, p. 3-4, lines 5-16.

²⁴³ D.18-06-029, p. 7, citing D.94-06-033.

²⁴⁴ D.94-06-033; 1994 Cal. PUC LEXIS 428, *63; 55 CPUC2d 158.

finance those assets.²⁴⁵ If the utility’s financial health unduly worsens, its credit ratings will be lowered, and its cost of capital will increase. As a corollary, customer rates would increase to reflect the higher cost of capital. While PG&E acknowledges that memorandum accounts provide a mechanism for ex-post reasonableness review, if they are broadly used in place of current rate recovery, the amounts in these accounts can reach levels that adversely impact PG&E’s financial health.

Further, as PG&E witness David Thomason explained, through the first quarter of 2022, PG&E had \$4.7 billion of unrecovered wildfire mitigation and catastrophic event related costs accumulated on its balance sheet. These amounts are tracked in various balancing and memorandum accounts and will be recovered through separate applications.²⁴⁶ The consequence of not having current recovery of these costs is a substantial deterioration against credit quality criteria which would be greatly exacerbated if the intervenor proposals described above were to be implemented.²⁴⁷

2.5.3.2 The Commission Should Approve Funding For Costs Of Service And Not Require “Shareholder Contributions” For Ordinary Operating Expenses

Cal Advocates and TURN argue that PG&E’s shareholders, rather than customers, should fund many of PG&E’s legitimate costs to provide service, including infrastructure investments, employee compensation, and liability insurance. Intervenors use the term “share” as a euphemism for disallowance, since the effect of “sharing” costs is simply a reduction of PG&E’s revenue requirement. Some of the larger proposed disallowances are summarized in Table 2-1 below.²⁴⁸

²⁴⁵ PG&E-14, p. 3-5, lines 2-7.

²⁴⁶ PG&E-14, p. 3-21, lines 15-22.

²⁴⁷ PG&E-14, p. 3-21, line 22 to p. 3-22, line 2.

²⁴⁸ PG&E-14, p. 3-10, Table 3-2.

**TABLE 2-1
COSTS PROPOSED TO BE DISALLOWED
(MILLIONS OF DOLLARS)**

Line No.	Intervenor	Cost Description	2021-2026	2023
			Capital	Expense
1	Cal Advocates	Gas AMI Meter Modules	\$388	—
2	Cal Advocates	Wildfire Insurance Premium	—	\$354
3	Cal Advocates	Short-term Incentive Plan	—	\$145
4	TURN	Gas AMI Meter Modules	\$581	\$10
5	TURN	Wildfire Insurance Premium	—	\$370-\$783
6	TURN	Short Term Incentive Plan	—	\$145

These proposals are also inconsistent with the cost-of-service ratemaking principles described earlier in this brief.

Customers benefit from the utility’s ability to invest in utility infrastructure by receiving safe and reliable service. If the Commission routinely requires utility shareholders to fund costs typically recovered in utility rates, such a practice would discourage investors from investing in PG&E, which could increase the cost of capital for PG&E customers.²⁴⁹ Further, diminishing returns on invested capital translate directly to worsening credit metrics, and the potential for credit rating downgrades.²⁵⁰ As the Legislature stated in AB 1054, lower credit ratings harm customers.²⁵¹

When utilities bear these costs with no offsetting revenue, there is a one-to-one reduction in the cash available to service PG&E’s debt. For example, proposals to disallow the cost of PG&E’s short term incentive program (STIP), insurance premium for wildfire liabilities, and costs of replacing defective gas AMI modules, if all approved, could result in a reduction to

²⁴⁹ PG&E-14, p. 3-11, lines 3-16.

²⁵⁰ PG&E-14, p. 3-11, line 13 to p. 3-12, line 5.

²⁵¹ In AB 1054, the Legislature discussed the potential harm to customers that could arise if the credit ratings of electric utilities are downgraded to “junk bond status.” It stated:
 “All the major electrical corporations have had their credit ratings lowered to junk bond status or are at risk of downgrades to junk bond status. This jeopardizes the ability of these corporations to provide safe and reliable electric and gas service, to reduce the risk of future catastrophes, to provide service at just and reasonable rates, to meet the state’s mandates to reduce carbon emissions, and to address the risks of climate change.” Pub. Util. Code § 854.2(a)(6).

PG&E's primary credit metric (i.e., Funds from Operations to Total Debt (FFO/Debt)) on the order of one percent.²⁵² A drop in the FFO/Debt ratio could ultimately result in a reduced credit rating, which would make it more expensive for PG&E to access capital from the capital markets.²⁵³

2.5.3.3 The Commission Should Not Adopt Policies That Encourage Use Of Debt To Finance Permanent Assets

TURN proposes to deny PG&E ratebase treatment of our Undergrounding Program investments and instead proposes that PG&E finance such investments with debt. TURN claims: "to the extent ratepayers bear costs of the undergrounding program, any large--scale proposal should be financed entirely by debt, without a return on equity component."²⁵⁴ TURN posits that this "represents a less costly alternative" that would "save approximately \$18 billion in return on equity and income taxes over the 50-year depreciation life of PG&E's GRC proposal."²⁵⁵

The Commission recognizes that long-term cash requirements should be financed with long-term capital sources.²⁵⁶ PG&E's appropriate capital structure (debt-equity ratio) is established in cost of capital cases. The Commission considers the capitalization ratios for each utility after holding hearings based on detailed presentations, including evidence relating to the impact of leverage on credit ratings. PG&E is required by the so-called equity maintenance

²⁵² PG&E-14, p. 3-12, lines 8-14.

²⁵³ PG&E-14, p. 3-12, lines 14-19.

²⁵⁴ TURN-11, p. 48, lines 10-12.

²⁵⁵ TURN-11, p. 48, lines 12-17 (fn. omitted).

²⁵⁶ D.14-08-032, p. 622.

condition to maintain our average equity ratio at no less than that authorized by the CPUC in PG&E's cost of capital proceedings, currently 52 percent.²⁵⁷

The Commission also agrees that leverage is an integral part of financial risk and the cost of equity:

Financial risk is tied to the utility's capital structure. The proportion of its debt to permanent capital determines the level of financial risk that a utility faces. As a utility's debt ratio increases, a higher return on equity may be needed to compensate for that increased risk.²⁵⁸

One role of the Commission is to ensure that the utilities it regulates are not financed with excessive amounts of debt that could jeopardize their financial health and ability to meet their obligation to serve.²⁵⁹ Adoption of TURN's proposal would effectively circumvent the CPUC's capital structure requirement (and estimate of equity risk) by having PG&E replace long-term debt and equity with permanent debt financing that is not included in the normal calculation of PG&E's capital structure for compliance purposes.²⁶⁰ If PG&E were to refinance all of our undergrounding proposal with debt, our equity ratio would decrease, falling well below the 52 percent equity ratio the Commission found to be reasonable in PG&E's most recent cost of capital proceeding.

Increasing leverage with additional debt on a permanent basis would also lower PG&E's credit metrics, which are already weakened in part by the high level of debt PG&E used to finance our exit from bankruptcy.²⁶¹ As PG&E's Chief Financial Officer David Thomason

²⁵⁷ D.19-12-056, pp. 6–12. The Commission has consistently maintained PG&E's authorized common equity ratio at 52 percent since 2005. See D.04-12-047, p. 51 (OP 3); D.05-12-043, p. 44–45 (OP 1); D.07-12-049, p. 58 (OP 3); D.12-12-034, 53 (OP 4).

²⁵⁸ D.12-12-034, p. 29.

²⁵⁹ Because the level of financial risk that the utilities face is determined in part by the proportion of their debt to permanent capital, or leverage, we must ensure that the utilities' adopted equity ratios are sufficient to maintain reasonable credit ratings and to attract capital." D.07-12-049, p. 4; *Accord*, D.19-12-056, p. 6.

²⁶⁰ PG&E-14, p. 3-16, lines 7-15.

²⁶¹ PG&E-14, p. 3-13, lines 27-29.

explained, “[t]he overall proportions of debt and equity are critical to PG&E’s credit ratings, and hence the cost of debt, as well as to PG&E’s continuing ability to maintain liquidity.”²⁶² The Commission has recognized the need to support an investment-grade credit rating for the utilities to enable them “to raise money necessary for the proper discharge of their public duty.”²⁶³

TURN’s claim that financing the undergrounding with debt would save customers \$18 billion is incorrect.²⁶⁴ Adding long-term debt to finance any particular asset generally does not reduce the overall cost of capital: the carrying cost of the asset being financed 100 percent with long-term debt will appear to be lower, but the carrying cost of every other asset will increase. Or, PG&E could maintain the same overall leverage by financing an equivalent amount of other assets with all equity to offset the assets that are financed with all debt. Either way, the overall cost of capital from the customers' perspective will not decrease.

Finally, requiring PG&E to finance our wildfire mitigation capital expenditures with debt would be inconsistent with AB 1054 which orders the Commission to require PG&E to fund \$3.2 billion in wildfire mitigation capital expenditures. Public Utilities Code Section 8386.3(e) states:

(e) The commission shall not allow a large electrical corporation to include in its equity rate base its share, as determined pursuant to the Wildfire Fund allocation metric specified in Section 3280, of the first five billion dollars (\$5,000,000,000) expended in aggregate by large electrical corporations on fire risk mitigation capital expenditures included in the electrical corporations’ approved wildfire mitigation plans. An electrical corporation’s share of the fire risk mitigation capital expenditures and the debt financing costs of these fire risk mitigation capital expenditures may be financed through a financing order pursuant to Section 851, subject to the requirements of that financing order.

This statute requires PG&E to finance \$3.2 billion in wildfire system hardening with debt and allows such debt to be securitized.²⁶⁵ As PG&E witness David Thomason explained,

²⁶² PG&E-14, p. 3-16, lines 1-4.

²⁶³ D.19-12-056, p. 26.

²⁶⁴ TURN-11, p. 48, lines 12-17 (fn. omitted).

²⁶⁵ Pub. Util. Code §8386.3(e). PG&E’s initial allocation of this amount is 64.2 percent pursuant to Pub. Util. Code, § 3280(n)(2) or \$3.2 billion.

PG&E will have complied with AB 1054 requirements by 2023.²⁶⁶ Requiring PG&E to fund further wildfire system hardening with debt would circumvent the specific amounts of required debt financing the Legislature mandated in AB 1054.²⁶⁷ Altering precise numerical terms overrides unambiguous statutory terms and modifies Legislative intent.²⁶⁸ Where the Legislature has struck a carefully considered balance between competing interests in favor of a specific directive, general grants of authority do not empower the Commission to override Legislative intent.²⁶⁹ The California Supreme Court has “rejected a construction of section 701 that would confer upon the Commission powers contrary to other legislative directives.”²⁷⁰ No matter how broad a grant of general authority, it does not empower an agency to contravene the expressed will of the Legislature.²⁷¹

Requiring PG&E to finance our wildfire mitigation capital expenditures exclusively with debt would also be contrary to SB 884, which requires only that a utility apply for federal, state, and other non-ratepayer funding to reduce the cost of undergrounding.²⁷² SB 884 requires a

²⁶⁶ PG&E-14, p. 3-14, lines 20-24.

²⁶⁷ See, e.g., *Morris v. Williams*, 67 Cal. 2d 733, 748 (1967) (“Administrative regulations that alter or amend the statute or enlarge or impair its scope are void and courts not only may, but it is their obligation to strike down such regulations.”).

²⁶⁸ See, e.g., *Util. Air Regul. Grp. v. EPA*, 573 U.S. 302, 325-26 (2014) (“An agency has no power to ‘tailor’ legislation to bureaucratic policy goals by rewriting unambiguous statutory terms. . . . It is hard to imagine a statutory term less ambiguous than the[se] precise numerical thresholds When EPA replaced those numbers with others of its own choosing, it went well beyond the ‘bounds of its statutory authority.’” (quoting *Arlington v. FCC*, 569 U.S.290, 297 (2013))).

²⁶⁹ See, e.g., *Southern Cal. Gas Co. v. Public Util. Com.*, 24 Cal. 3d 653, 659-60 (1979) (“The commission also lacks the authority to disregard the specific financing provisions set forth The Legislature gave careful consideration to the financing provisions The legislative history and specificity . . . belie the commission’s assertion that the Legislature intended for the commission to be authorized to impose different financing terms.”).

²⁷⁰ *Assembly v. Public Util. Com.*, 12 Cal. 4th 87, 103 (1995).

²⁷¹ See, e.g., *BNSF Railway Co. v. Pub. Util. Com.*, 218 Cal. App. 4th 778, 785 (2013) (“[H]owever broad the scope of the commission's authority over railroad crossings may be, the commission does not have the authority to contravene the expressed will of the Legislature in this area.”).

²⁷² Sen. Bill No. 884 (2021-2022 Reg. Sess.) § 2 (Pub. Util. Code § 8388.5(j)).

utility to make showings around cost reduction strategies and declining cost targets, but nowhere suggests debt-only financing is required.²⁷³ Indeed, SB 884 directs the Commission to consider continuing existing commission-approved ratemaking mechanisms in its review of an undergrounding plan.²⁷⁴

Accordingly, TURN's financing proposal for undergrounding must be rejected as inconsistent with the Commission's approved debt-equity ratio requirements, long-standing ratemaking decisions allowing PG&E an opportunity to earn a rate of return on capital investments,²⁷⁵ and AB 1054.

2.5.3.4 The Commission Should Deny TURN's Unlawful and Unsubstantiated Proposals To Establish A GRC Revenue Requirement Based on the Consumer Price Index

TURN's proposal that the Commission: (1) limit PG&E's "authorized spending" in this proceeding to an amount not exceeding the Consumer Price Index (CPI); and (2) order PG&E in our next rate case to prepare a forecast capped at the rate of CPI should both be denied as unlawful and inconsistent with established utility ratemaking. TURN's proposal would also provide insufficient funding for safe and reliable operations. There is no evidence in this proceeding that PG&E could operate safely and reliably with such a reduced revenue requirement.

²⁷³ *Id.* at 8388.5(e). Unlike the wildfire mitigation capital expenditures addressed in Pub. Util. Code § 8386.3(e), SB 884 does not direct utilities to use debt only financing for undergrounding, which strongly suggests that traditional financing is appropriate for funding such activities.

²⁷⁴ *Id.*

²⁷⁵ D.12-11-051, p. 10; also see *Southern Cal. Gas Co. v. Public Utilities Com.* (1979) 23 Cal. 3d 470, 476, citing *City and County of San Francisco v. Public Utilities Com.* (1971) 6 Cal.3d 119, 129.

2.5.3.4.1 TURN's Proposals to Cap Spending at the Consumer Price Index Would Violate the Regulatory Compact and Provide Insufficient Funding to Safely Operate the Utility

TURN's proposal to limit PG&E's "authorized spending" increases at the rate of CPI is neither good policy, viable, nor lawful.²⁷⁶ TURN's proposal would require the Commission to either lower standards for safety and reliability or require PG&E to forego recovery of the costs of prudent investments. Adopting a forecast based on either premise would constitute poor public policy and violate California law and cost-of-service ratemaking principles require PG&E to provide gas and electric service in exchange for our reasonable costs in doing so.²⁷⁷

Constraining PG&E's costs to an arbitrary rate of the CPI – which is completely irrelevant to the costs to operate a utility²⁷⁸ – would prevent PG&E from meeting these crucial requirements and objectives, a result that should not be acceptable to this Commission.²⁷⁹

TURN argues that approval of a revenue requirement that is sufficient to cover PG&E's actual costs is not legally mandated, yet *"PG&E is responsible for providing safe and reliable customer service whether or not its overall spending matches funding levels authorized or imputed in rates."*²⁸⁰ TURN argues that if its advocacy is successful and PG&E does not earn our rate of return, this does not "abrogate PG&E's responsibility to provide safe and reliable service,"²⁸¹ a classic "heads I win, tails you lose" argument.

²⁷⁶ TURN-03, p. 37, lines 3-6.

²⁷⁷ D.12-11-051, p. 10; D.19-05-020, p. 9.

²⁷⁸ PG&E-14, p. 3-23, lines 9-13; PG&E-24-E, p. 1-15, line 25 to p. 1-16, line 2.

²⁷⁹ Adopting an alternative, non-cost-based forecast may also run afoul of the Takings Clause of the United States Constitution, to the extent that the Commission or Legislature require the utilities to provide safe, reliable and clean service to customers but do not allow them the reasonable opportunity to recover the costs associated with doing so.

²⁸⁰ PG&E-14, TURN's response to Data Request PGE_TURN005-Q10, dated 6/23/22, p. AppA-9 (emphasis added).

²⁸¹ PG&E-14, TURN's response to Data Request PGE_TURN005-Q10, dated 6/23/22, p. AppA-9.

While it is critical that the Commission approve rates that are sufficient to cover utility costs, it is notable that for many years we have shouldered hundreds of millions of dollars in costs for safety work for which there is no revenue requirement or certainty of cost recovery.²⁸² This spending above authorized amounts by PG&E to pay for our actual costs of service -- largely due to wildfire mitigation requirements to address climate change -- is detrimental to the utility's financial health and is not sustainable.

For these reasons, TURN's proposals that the Commission: (1) limit PG&E's "authorized spending" in this proceeding to an amount not exceeding the CPI and (2) order PG&E in our next rate case to prepare a forecast that it does not support should both be denied.

2.5.3.4.2 The Consumer Price Index Has No Relation To Utility Costs

The CPI should not be used as an alternate to an examination of actual costs to operate the utility for the additional reason that it is an indicator of price trends that is wholly unrelated to the costs to operate a utility. TURN itself admits that the CPI does not relate to the amount of costs that the utility incurs.²⁸³

The CPI does not measure increases in utility costs, the cost of labor, or wage growth. Nor is CPI specific to California.²⁸⁴ Rather it is a general indicator of the increases in the cost of living *throughout the United States*.²⁸⁵ The CPI represents changes in the national prices of a market basket of goods and services purchased for consumption by urban households.²⁸⁶ It does not reflect California specific cost pressures -- such as labor and equipment costs -- that impact utility costs.²⁸⁷ It also does not meaningfully reflect utility-specific cost pressures to reduce

²⁸² PG&E-14, p. 3-18, line 16 to p. 3-19, line 18.

²⁸³ PG&E-14, TURN's response to Data Request PGE_TURN005-Q10, dated 6/23/22, p. AppA-9.

²⁸⁴ PG&E-14, p. 3-24 line 21 to p. 3-25, line 7; Tr. Vol. 14, 2689:1 to 2690:7, PG&E/Griffes.

²⁸⁵ D.04-07-022, p. 346, Findings of Fact (FOF) 229.

²⁸⁶ PG&E-14, TURN's response to Data Request PGE_TURN005-Q02, dated 6/23/22, p. AppA-6.

²⁸⁷ D.13-05-010, p. 982.

wildfire risk and lead the transition to California’s clean energy-based economy. Moreover, the CPI may be reduced by technological change and lower production costs, whether caused by efficiency improvement or increased imports. The Commission explained at length its rationale for rejecting use of the CPI to establish rates in both PG&E’s 2014 GRC decision²⁸⁸ and SCE’s 2003 GRC decision.²⁸⁹ The Commission has continued to reach this same result in more recent GRCs, concluding, *again*, that the CPI “does not reflect how utilities incur costs.”²⁹⁰ Simply put, use of the CPI is not a valid way to forecast utility costs.

Notably, TURN’s testimony does not contain a portfolio capped at the CPI.²⁹¹ There is no evidence in the record of an alternate portfolio of work that would fit within TURN’s CPI-based revenue requirement. Under an illustrative example provided in TURN’s testimony, PG&E’s spending in 2023 would be capped at an increase of \$0.31 billion – less than one tenth- of PG&E’s forecast.²⁹² By contrast, Cal Advocates, which did a more complete review of PG&E’s portfolio, proposes an incremental revenue requirement increase of \$1.139 billion.²⁹³ Contradicting its position that the rate of CPI should be a sufficient revenue requirement to operate the facility, TURN also asserts that PG&E needs to spend whatever it takes to provide safe and reliable service, even where the spending that is necessary to do so

²⁸⁸ D.14-08-032, p. 653 (“The CPI reflects consumer retail price changes, not the escalation in wholesale purchases of utility goods and services.”).

²⁸⁹ D.04-07-022, p. 278. (“The CPI may be a simple, accessible measure of general inflation faced by urban U.S. consumers, but that alone does not make it appropriate as a measure of price changes faced by an electric utility. It does not specifically cover the prices of the typical goods SCE purchases. Conversely, SCE’s proposed escalation rates were not designed to track the general level of inflation, and there is no reason why they should do so.”).

²⁹⁰ D.15-11-021, pp. 390-391; D.19-09-051, p. 707.

²⁹¹ TURN-03, p. 35, line 12 to p. 36, line 8; p. 40, line 16 to p. 41, line 3.; PG&E-14, p. 3-26, line 27 to p. 3-27, line 4.

²⁹² TURN-03, p. 39, Table 10.

²⁹³ CALPA-01, p. 1.

exceeds the approved GRC revenue requirement.²⁹⁴ Thus, while TURN promotes the fiction that PG&E can operate within a CPI cap, TURN acknowledges that PG&E would potentially be required to operate at a loss to provide safe and reliable service. Establishing PG&E's revenue requirement at an arbitrary price unrelated to the cost to operate the utility would violate the regulatory compact, which requires the revenue requirement to be based on PG&E's costs of service.²⁹⁵

There is no evidence in this proceeding, that PG&E could operate our gas, electric and generation facilities safely and reliably if it were limited to an increase measured by the CPI as proposed by TURN. TURN's proposal must be denied.

2.5.3.4.3 PG&E Should Not Be Compelled to Propose a CPI-Capped Forecast in the 2027 GRC

TURN also renews a prior request in this proceeding that PG&E²⁹⁶ and other parties²⁹⁷ opposed and the Assigned Commissioner properly rejected in her Scoping Memo.²⁹⁸ TURN again asks the Commission to require PG&E to submit an alternate GRC forecast analysis capped at the then existing- CPI in the next GRC, which for PG&E is the 2027 GRC.²⁹⁹ The

²⁹⁴ PG&E-14, TURN's response to Data Request PGE_TURN005-Q10, dated 6/23/22, p. AppA-9.

²⁹⁵ *Missouri ex rel. Southwestern Bell Tel. Co. v. Public Service Com.*, (1923) 262 U.S. 276, 287-288; *Southern Cal. Edison Co. v. Public Utilities Com.*, (1978) 20 Cal.3d 813, 818-819 (emphasis added).

²⁹⁶ *See Pacific Gas and Electric Company's Response to Motion of the Utility Reform Network to Require Pacific Gas and Electric Company to Supplement its Testimony with an Inflation-Constrained Alternative Spending Plan* (Aug. 20, 2021).

²⁹⁷ *Southern California Edison Company's (U 338-E) Response To Motion Of The Utility Reform Network To Require Pacific Gas and Electric Company To Supplement Its Testimony With an Inflation-Constrained Alternative Spending Plan* (Aug. 20, 2021); *Southern California Gas Company (U 904 G) And San Diego Gas & Electric Company (U 902 M) Response To Motion Of The Utility Reform Network To Require Pacific Gas And Electric Company (U 39 M) To Supplement Its Testimony With An Inflation-Constrained Alternative Spending Plan* (Aug. 20, 2021).

²⁹⁸ *Assigned Commissioner's Scoping Memo and Ruling* (Oct. 1, 2021) (Scoping Memo), p. 9.

²⁹⁹ TURN-03, p. 41, line 4 to p. 44, line 8.

request mirrors a similar request that TURN unsuccessfully proposed in other Commission proceedings.³⁰⁰ TURN more recently submitted the same or similar proposal in the Commission’s Affordability OIR, where the proposal will be considered in the third phase of the proceeding.³⁰¹

PG&E has an obligation to provide safe and reliable service to customers and must address the reality of running the utility day-to-day in real world conditions with increasing costs of service. As PG&E witness David Thomason explained:

Operating the utility safely and reliably requires sufficient funding to execute on the work needed to serve our customers. . . . [T]he Commission should not require PG&E or any other utility to submit a fictional GRC forecast artificially capped at the rate of consumer inflation.

Requiring the utilities to sponsor an “alternative proposal” that is not tied to realistic projected costs to operate the utility safely and reliably, as TURN proposes, could put the state on a dangerous path. Utilities’ GRC proposals must balance minimizing costs with objectives like minimizing the risk of catastrophic wildfire or gas explosion. This can include hardening and modernizing infrastructure with improved engineering, system design, standards, equipment, and facilities.³⁰²

As a practical matter, if utility prices continue to increase beyond the rate of the CPI, a utility proposal capped at the CPI that the utility does not support would have no evidentiary value and would serve to confuse rather than clarify the evidentiary record.³⁰³ Further, as

³⁰⁰ See D.21-07-017, *Decision Regarding Petition for Modification of Decision 20-12-005* (Commission rejected TURN’s proposal to require PG&E to file a CPI-capped forecast in the 2023 GRC); *Email Ruling Denying the Motion to Require and Inflation-Constrained Alternative*, A.20-06-012 (June 14, 2021) (rejecting TURN’s proposal in PG&E’s 2020 RAMP application proceeding).

³⁰¹ *Assigned Commissioner’s Ruling Amending Ruling of May 20, 2022 and Further Updating Proceeding Schedule for Phase 3 of Proceeding* (June 9, 2022), R.18-07-006, p. 2.

³⁰² PG&E-14, p. 3-26, lines 8-26.

³⁰³ PG&E-14, p. 3-27, lines 4-8.

SoCalGas and SDG&E indicated in their opposition to TURN’s request, forcing the utility to produce such testimony would raise serious constitutional concerns about forced speech.³⁰⁴

Finally, the Commission’s Rate Case Plan decisions dating back to the 1980s have specific requirements for the utility to submit evidence of its costs of service based on lawful cost of service ratemaking principals.³⁰⁵ TURN’s proposal to require PG&E to provide an alternate forecast capped at the CPI in the next GRC should be rejected in favor of normal, lawful utility ratemaking consistent with the Commission’s long-standing Rate Case Plan decisions. In any event, if the Commission is considering adopting any process that would modify the Rate Case Plan as substantially as TURN proposes, the Commission should consider such a proposal in a Rate Case Plan proceeding where all the IOUs and interested parties could comment on such a proposal.

2.6 Climate Resilience

Meeting the challenge of climate change is central to our corporate mission and values. Our commitment includes aligning our resources and business strategy with California’s clean energy goals and advocating for policies and programs that enable safe and reliable energy for our customers, while also working to reduce the ever-growing threat of extreme weather and wildfires. In the coming years and decades, we must think of extreme weather conditions, as well as chronic conditions like sea level rise, not as unprecedented, but as expected. Our decisions on investments in our system must take into consideration the likelihood and consequences of changing climate conditions, so we can operate safely and reliably even as the

³⁰⁴ *Southern California Gas Company (U 904 G) and San Diego Gas & Electric Company (U 902 M) Response to Motion of The Utility Reform Network to Require Pacific Gas And Electric Company (U 39 M) To Supplement Its Testimony With An Inflation-Constrained Alternative Spending Plan* (Aug. 20, 2021), p. 2 “forcing PG&E to adopt proposals that the utility does not agree with, and prepare to defend them, would violate PG&E’s First and Fifth Amendment Rights. PG&E cannot be compelled to testify and support a position against itself in this circumstance.” and pp. 7-10.

³⁰⁵ See e.g. D.89-01-040; D.07-07-004; D.20-01-002.

environment around us continues to change.³⁰⁶ PG&E's climate resilience work is based on three pillars:

- first, bringing forward looking climate data into internal decision making;
- second, working with policymakers and regulators to advance climate adaptation policies and initiatives; and
- third, collaborating with local governments and communities on adaptation solutions.³⁰⁷

In our opening testimony, we described the expected climate conditions during the 2023 GRC rate case period and the impact of these changes.³⁰⁸ And we explained how climate change considerations are being incorporated into our GRC.³⁰⁹ Finally, we discussed how we will be preparing for and addressing climate change on a longer-term basis including: (1) reviewing our design standards, (2) updating asset management standards to consider climate change; (3) updating risk modeling; (4) planning for extreme weather events; and (5) building strong community partnerships.³¹⁰

California is at the forefront of efforts to mitigate the threat of climate change, as well as experiencing its devastating impacts. Climate change mitigation and adaptation activities are mutually supportive, as every investment in climate change mitigation and greenhouse gas reductions can help avoid worst-case scenarios in terms of climate change impacts. While meeting this challenge requires a collective approach, PG&E intends not just to support, but also to lead, this effort through our decision-making and operations.

³⁰⁶ PG&E-02, p. 4-1, lines 13-27.

³⁰⁷ PG&E-02, p. 4-2, lines 9-13.

³⁰⁸ PG&E-02, p. 4-2, line 21 to p. 4-4, line 3.

³⁰⁹ PG&E-02, p. 4-7, lines 3-22.

³¹⁰ PG&E-02, p. 4-5, line 15 to p. 4-6, line 23.

3. GAS OPERATIONS (EXHIBIT PG&E-03)

Exhibit PG&E-03 presents Gas Operations' expense and capital expenditures forecast to operate and maintain PG&E's natural gas transmission, storage, and distribution system safely and reliably from 2023 to 2026. PG&E's Gas Transmission and Storage (GT&S) system is composed of approximately 6,600 miles of transmission pipeline, 38 compressor units at nine compressor stations, and 456 pressure regulating stations. PG&E also owns and operates three gas storage facilities³¹¹ and has interest in a fourth. PG&E-owned storage facilities include 109 storage wells, 14 miles of transmission pipes, well controls for each injection and withdrawal wells, and 3,404 acres of reservoirs with over 52 billion cubic feet of working gas capacity. PG&E's gas distribution system is composed of approximately 43,000 miles of distribution mains, approximately 3.6 million gas services, and approximately 4.6 million gas meters which together provide gas to PG&E's 4.3 million residential, commercial, and industrial customers.³¹²

PG&E submitted hundreds of pages of testimony and extensive and detailed workpapers in Exhibits PG&E-03 and PG&E-16 to support Gas Operations' programs and forecasts. This extensive record demonstrates that PG&E's expense and capital forecasts are just, reasonable and prudent and that its Gas Operations programs are necessary for the safe, reliable, and cost-effective operation of PG&E's natural gas transmission, distribution, and storage facilities. In this section of our Opening Brief, we describe our gas transmission, distribution and storage expense and capital expenditure forecasts and address programs and issues that have been disputed by the parties.

³¹¹ PG&E is currently in the process of seeking to sell or decommission the Pleasant Creek facility. See PG&E-03, p. 7-59, lines 15-24 for additional information.

³¹² PG&E-03, p. 1-1, lines 11-21.

3.1 Expense and Capital Forecast

After submitting initial testimony, PG&E updated its GT&S 2023 expense forecasts, certain of its GT&S attrition years expense forecasts, and its Gas Distribution (GD) and GT&S 2023 through 2026 capital forecasts to correct for an escalation factor error.³¹³ Correcting this escalation factor error resulted in a reduction to PG&E's Gas Operations expense and capital forecasts (Corrected Forecast). PG&E further updated its forecasts in the Joint Comparison Exhibit (JCE) (Exhibit PG&E-64) to account for a change in escalation factors in PG&E's September 2022 Update Testimony. Below, PG&E provides both the corrected expense and capital forecasts.

With these modifications, we are providing an overview of the Gas Operations Corrected Forecasts for expense and capital expenditures for Gas Operations, GD, and GT&S in Table 3-1, followed by a narrative description of these forecasts with citations to the evidence in this proceeding, as well as the JCE forecasts:

TABLE 3-1
GAS OPERATIONS OVERVIEW OF CORRECTED FORECAST FOR EXPENSE AND CAPITAL EXPENDITURE (\$ MILLIONS)

	2023	2024	2025	2026
Gas Operations – Expense (Corrected Forecast)	\$1,212.412			
Gas Operations – Capital (Corrected Forecast)	\$2,282.565			
Expense by GD and GT&S				
GD – Expense (Corrected Forecast)	\$572.464			
GT&S – Expense (Corrected Forecast)	\$639.948			
Capital by GD and GT&S				
GD – Capital (Corrected Forecast)	\$1,241.327	\$1,277.511	\$1,327.452	\$1,339.263
GT&S – Capital (Corrected Forecast)	\$1,041.237	\$1,082.621	\$1,010.937	\$1,004.534

In narrative form, PG&E's TY 2023 Corrected Forecast for GD expense is \$572.464 million.³¹⁴ PG&E's TY 2023 Corrected Forecast for GT&S expense is \$639.948 million.³¹⁵

³¹³ PG&E-16-E, p. 2-1, line 25 to p. 2-3, line 15.

³¹⁴ PG&E-16-E, p. 2-5, Table 2-1, line 10.

³¹⁵ PG&E-3-ES, sum of pp. iii and iv, which reflects PG&E's rebuttal forecast updated with corrected escalation factors.

PG&E's Gas Operations TY 2023 Corrected Forecast for expense is \$1,212.412 million,³¹⁶ of which approximately \$524 million, or 43 percent, is uncontested.³¹⁷ PG&E's Gas Operations TY 2023 JCE forecast for expense is \$1,316.806 million.³¹⁸

PG&E's Corrected Forecast for GD capital is \$1,131.682 million in 2021, \$1,267.667 million in 2022, \$1,241.327 million in 2023, \$1,277.511 million in 2024, \$1,327.452 million in 2025, and \$1,339.263 million in 2026. PG&E's JCE forecast for GD capital is \$1,189.163 million in 2021, \$1,403.458 million in 2022, \$1,391.961 million in 2023, \$1,395.511 million in 2024, \$1,416.443 million in 2025, and \$1,394.926 million in 2026.³¹⁹

PG&E's Corrected Forecast for GT&S capital is \$822.722 million in 2021, \$808.069 million in 2022, \$1,041.237 million in 2023, \$1,082.621 million in 2024, \$1,010.937 million in 2025, and \$1,004.534 million in 2026.³²⁰ PG&E's JCE forecast for GT&S capital is \$996.050 million in 2021, \$1,091.726 million in 2022, and \$1,313.251 million in 2023, \$1,226.462 million in 2024, \$1,091.439 million in 2025 and \$1,055.326 million in 2026.³²¹

³¹⁶ PG&E-64, p. 3-1, Table 3A-1, Total Exhibit (PG&E-03).

³¹⁷ See Appendix A, p. A-9, line 163. Calculated as: \$524 million / \$1,212 million = 43%.

³¹⁸ PG&E-64, p. 3-1, Table 3A-1, Total Exhibit (PG&E-03).

³¹⁹ PG&E-64, p. 3-6, Table 3B-1, sum of GT line items (2023); p. 3-10, Table 3B-2, sum of GT line items (2022); and p. 3-14, Table 3B-3, sum of GD line items (2021). JCE forecast amounts for 2024-2026 are not provided in the JCE but included here for reference.

³²⁰ PG&E-16-E, p. 2-8, Table 2-4, line 9 (2021); p. 2-10, Table 2-6, line 9, (2022); PG&E-3-ES, p. v, which reflects PG&E's rebuttal forecast updated with corrected escalation factors, (2023-2026).

³²¹ PG&E-64, p. 3-6, Table 3B-1, sum of GT line items (2023); p. 3-10, Table 3B-2, sum of GT line items (2022); and p. 3-14, Table 3B-3, sum of GT line items (2021). JCE forecast amounts for 2024-2026 are not provided in the JCE but included here for reference.

PG&E's Gas Operations TY 2023 Corrected Forecast for capital is \$2,282.565 million,³²² of which approximately \$751 million (33 percent) is uncontested.³²³ The Gas Operations JCE forecast for capital for 2023 is \$2,705.212 million.³²⁴

3.2 Gas Operations Risk Management

In Chapter 3 of Exhibit PG&E-03, PG&E describes the risks associated with its gas transmission (GT), distribution, and storage facilities, and the processes and tools it has developed to manage these risks.³²⁵ This chapter also describes each of the Gas Operations or "GO" risks on PG&E's Corporate Risk Register (CRR) and provides an update to the risk management strategy and risk modeling for those Gas Operations risks that were included in PG&E's 2020 RAMP Report.³²⁶ No party challenged PG&E's Gas Operations' risk analysis other than TURN. In Section 3.2.1 below, PG&E provides an overview of Gas Operations' risk management strategy. The issues raised by TURN are addressed in Section 3.2.2.

3.2.1 Overview of Gas Operations Risk Management Testimony

3.2.1.1 Risk Management Organizational Structure and Governance

As part of its Gas Safety Excellence Management System and focus on public and employee safety, PG&E has implemented an asset management system to maintain the safe, reliable, and affordable management and operation of PG&E's gas assets.³²⁷ PG&E's asset management system focuses on:

- Identifying and reducing operational and enterprise risk;
- Maintaining an asset management framework and directing organizational focus on the most important asset risks and opportunities;

³²² PG&E-64, p. 3-6, Table 3B-1, Total Exhibit (PG&E-03).

³²³ See Appendix A, p. A-19, line 67. Calculated as: \$751 million/\$2,283 million = 33%.

³²⁴ PG&E-64, p. 3-6, Total Exhibit (PG&E-03).

³²⁵ PG&E-03, p. 3-1, lines 5-9.

³²⁶ PG&E's 2020 RAMP Report, A.20-06-012 (June 30, 2020).

³²⁷ PG&E-03, p. 3-1, lines 25-29, citing PG&E-03, Ch. 1, Section B.2.

- Proactively managing the condition of gas assets; and
- Meeting or exceeding the requirements of federal, state, and local codes, regulations, and requirements in an environmentally sustainable manner.³²⁸

PG&E has developed an asset family structure to recognize and manage the different types of risks associated with its assets and develop consistency in PG&E's risk analyses and mitigations. GO divides its gas system physical assets into nine asset families to manage and facilitate program prioritization. Each asset family has an Asset Family Owner (AFO) who is responsible for working with SMEs to identify and manage risks within the asset family and developing programs to mitigate the risks.³²⁹

3.2.1.2 Risk Management Process and Tools

Following the EORM risk management framework, the GO organization uses the Multi-Attribute Value Framework, bow-tie methodology, and RSE scores to evaluate risk and mitigation and control programs for its safety and reliability risks.³³⁰ In addition, as part of managing the safe and reliable operation of gas transmission and distribution assets, GO uses operational risk models to assess risk from an operations perspective. The outputs from these operational risk models are used as inputs to the EORM risk model for frequency and consequence data and as inputs to the GO Integrated Planning Process. These operational risk models are more granular in evaluating risks and threats at a component or segment level.³³¹

GO's primary risk management tools are the operational risk models for the Transmission Integrity Management Program (TIMP) and the Distribution Integrity Management Program (DIMP). Integrity management focuses on:

³²⁸ PG&E-03, p. 3-2, lines 1-9.

³²⁹ PG&E-03, p. 3-2, lines 11-18.

³³⁰ After filing the 2020 RAMP Report, PG&E updated its MAVF. These updates are discussed in PG&E-02, Ch. 1, Section E.5.

³³¹ PG&E-03, p. 3-5, line 30 to p. 3-6, line 7.

- Transporting and distributing natural gas in a safe, reliable, and efficient manner from transmission facilities through distribution mains to distribution service lines, and ultimately customer connected equipment; and
- Protecting customers and the general public, including their assets and property.

Integrity management provides the tools and processes for risk ranking and prioritization to enable PG&E to identify threats to its system and remediates them appropriately.³³²

While the integrity management programs contain many elements that overlap with the EORM risk assessment process, both TIMP and DIMP utilize a bottom-up process that considers threats to individual segments of pipe, as opposed to the system as a whole. In contrast, the EORM risk process is a top-down (event based) approach that considers threats from the enterprise level down. The combination of these complementary risk model methodologies results in a robust overall risk management process.³³³

3.2.1.3 Gas Operations Risk Events

PG&E's CRR includes the following nine GO risks. Three risks are identified as top safety risks in PG&E's 2020 RAMP Report (RAMP risks), and the remaining six risks are considered other safety and reliability risks (non-RAMP risks).³³⁴ Table 3-2 below identifies all nine GO risks.

³³² PG&E-03, p. 3-6, lines 9-21.

³³³ PG&E-03, p. 3-7, lines 5-11.

³³⁴ PG&E-03, p. 3-7, lines 20-23.

TABLE 3-2
GO CORPORATE RISK REGISTER RISKS³³⁵

Line No.	Risk Name	RISK ID	RAMP/ Non-RAMP Risk	Reference to 2020 RAMP Report
1	LOC on Gas Transmission Pipeline	LOCTM	RAMP Risk	Chapter 7
2	LOC on Gas Distribution Main or Service	LOCDM	RAMP Risk	Chapter 8
3	Large Overpressure Event Downstream of Gas M&C Facility	LRGOP	RAMP Risk	Chapter 9
4	LOC at Gas M&C or C&P Facility	MCCPF	Non-RAMP Risk	Chapter 19
5	LOC on Gas Customer Connected Equipment	CCEPQ	Non-RAMP Risk	Chapter 19
6	LOC at Natural Gas Storage Well or Reservoir	NGSWR	Non-RAMP Risk	Chapter 19
7	LOC on LNG/CNG Portable Equipment	LNCNG	Non-RAMP Risk	Chapter 19
8	LOC on CNG Station Equipment	CNGEQ	Non-RAMP Risk	Chapter 19
9	Insufficient Capacity to Meet Customer Demand	CPCTY	Non-RAMP Risk	N/A

For each of the three GO RAMP risks, Exhibit PG&E-03, Chapter 3 provides a detailed description of the risk overview; response to SPD and parties' feedback; risk modelling updates; and changes in risk management mitigations and controls, and risk modeling results.³³⁶ For each of the six non-RAMP risks, Chapter 3 provides a detailed description of the risk overview; Risk Management Mitigations and Controls; and SMAP proceeding supplemental analysis.³³⁷

3.2.2 TURN's Issues Regarding Gas Operations Risk Management

TURN, the only party that submitted testimony in response to Gas Operations Risk Management Chapter 3, raises five issues. First, TURN claims that PG&E's tranches are insufficiently granular for the following gas risk models: Loss of Containment on Gas Distribution Main or Service (LOCDM) (Gas Distribution Pipeline programs)³³⁸ and Loss of Containment on Gas Transmission Pipeline (LOCTM) (Gas Transmission Pipeline Programs).³³⁹

³³⁵ PG&E-03, p. 3-8, Table 3-1.

³³⁶ PG&E-03, p. 3-9, line 17 to p. 3-30, line 6, Section E.

³³⁷ PG&E-03, p. 3-30, line 7 to p. 3-40, line 2, Section F.

³³⁸ TURN-02, p. 73, line 10 to p. 91, line 3.

³³⁹ TURN-02, p. 91, line 4 to p. 108, line 14.

Second, TURN states that reducing Gas Operations’ forecast relative to Wildfire and other programs outside of Gas Operations is justified based on its claim that “the Commission should recognize that the updated risk scores for the risks analyzed by PG&E...are extremely low for the Gas-related risks, particularly in comparison to the Wildfire risk, which shows that there is relatively less Gas risk left to mitigate.”³⁴⁰

Third, TURN asserts that numerous Gas Distribution,³⁴¹ Gas Transmission,³⁴² Gas Facilities,³⁴³ and Gas Operations³⁴⁴ programs are not cost effective due to low RSE scores and benefit-cost ratios.

Fourth, TURN claims that “[t]he staff recommended that PG&E use the same density-based tranches as it did for the LOCTM and LOCDM risks, noting that such a change ‘would be closer to the level of rigor expected in the [S-MAP] Settlement Agreement’ [but] that PG&E did not make this change for the GRC.”³⁴⁵

Finally, TURN argues that PG&E was unable to provide an RSE for the Meter Protection Program as it relates to the Loss of Containment on Gas Customer Connected Equipment risk, and that “[t]he CPUC should require PG&E to provide the risk estimate for the next GRC, if not before, as it would be useful for determining program cost-effectiveness.”³⁴⁶

3.2.2.1 The Gas Operations Risk Model Tranches Are Reasonable

Specific to the LOCDM risk model, TURN claims that PG&E’s tranches are large and “contain tremendous variation among [Likelihood of Failure] LoF and [Consequence of Failure]

³⁴⁰ TURN-02, p. 131, lines 10-13.

³⁴¹ TURN-02, p. 73, line 10 to p. 91, line 3 and TURN-06, p. 33, lines 16-18.

³⁴² TURN-02, p. 91, line 4 to p. 108, line 14.

³⁴³ TURN-02, p. 109, line 1 to p. 120, line 13.

³⁴⁴ TURN-02, p. 120, line 14 to p. 128, line 13.

³⁴⁵ TURN-02, p. 113, lines 7-10 (fns. omitted).

³⁴⁶ TURN-06, p. 33, lines 16-18.

CoF values” and thus, TURN asserts, do not satisfy “the S-MAP Settlement’s requirement that tranches be homogenous with respect to both likelihood and consequence values.”³⁴⁷ TURN makes a similar claim for the LOCTM risk model.³⁴⁸ Neither of these claims is meritorious as explained below, and the Commission should find that PG&E’s tranching for the LOCDM and LOCTM is reasonable.

As a preliminary matter, PG&E’s TIMP and DIMP operational risk models are more granular than the LOCDM and LOTCM risk models in evaluating risks and threats at a component level or segment level.³⁴⁹ Operational risk models, such as TIMP and DIMP, and RAMP and GRC risk models, such as LOCDM and LOCTM, are different and serve different purposes. The operational risk models (*i.e.*, TIMP and DIMP) each contain millions of pipe segments and are used to prioritize work. This level of detail is too granular for RAMP/GRC risk models. As the number of tranches in a RAMP/GRC risk model grows, the data available to support the risk model within each tranche becomes increasingly sparse as much of the risk is driven by low frequency events. One can compensate for lack of data with SME judgment and industry averages, but this approach quickly defeats the purpose of having more granular tranches by creating greater uncertainty since the same averages are used across multiple tranches. Use of SME judgment and industry averages can lead to less confidence that risk scores and RSEs are accurate. Given this is the first generation of the risk models and tranche framework adopted in the S-MAP settlement agreement, the number of tranches in the LOCDM and LOCTM risk models is reasonable.³⁵⁰ Moreover, as explained below, the DIMP and TIMP models provide insight in the creation of meaningful and reasonable tranches and strike a balance between too few and too many tranches for RAMP/GRC risk models.

³⁴⁷ TURN-02, p. 84, lines 16-20.

³⁴⁸ TURN-02, p. 95, lines 5-13.

³⁴⁹ PG&E-03, p. 3-6, lines 6-7.

³⁵⁰ PG&E-16-E, p. 3-2, line 25 to p. 3-3, line 19.

With regard to the LOCDM risk model, in response to feedback from SPD and other parties to PG&E's 2020 RAMP Report,³⁵¹ PG&E made structural changes by increasing the number of tranches from 12 in the 2020 RAMP Report to 34 in the 2023 GRC. PG&E described the process for its development of the tranches for the LOCDM risk model in response to a TURN data request.³⁵² PG&E determined the LOCDM tranche exposures using the same input data as the DIMP operational risk model. The input data consists of asset type (mains, services, and risers), asset characteristics such as material (steel and plastic) and installation date, which was derived from PG&E's Gas Distribution Geographic Information System (GIS). The tranche definitions are based on the same definitions used in the DIMP model for steel and plastic assets, high population density, and indoor riser locations.³⁵³

TURN's claim that PG&E should have developed additional tranches for the LOCDM model³⁵⁴ ignores the limits of current data and risk modelling. PG&E made structural changes to the LOCDM risk model, increasing the number of tranches from 12 in the 2020 RAMP Report to 34 in the 2023 GRC. The increased number of tranches was based on information from the DIMP risk model, use of SME judgment, and use of PHMSA industry information. The determination to use 34 tranches was based on a need to strike the right balance between too few and too many tranches, using the risk profile information from the DIMP risk model. Additional granularity would result in some tranche and sub-driver combinations having insufficient event frequency data for a meaningful risk calculation. Applying industry average information to these

³⁵¹ Safety Policy Division Staff Evaluation Report on PG&E's 2020 RAMP A.20-06-012 (Nov. 25, 2020), p. 35.

³⁵² PG&E-16-E, PG&E's response to Data Request TURN_066_Q01Rev01Supp01, dated 3/23/22, pp. AppA-2 to AppA-13.

³⁵³ PG&E-16-E, p. 3-3, line 22 to p. 3-4, line 5.

³⁵⁴ TURN-02, p.85, lines 12-19; p. 85, lines 1-5; and p. 87, lines 3-4.

more granular tranches where they would all have the same risk profiles, would diminish the purpose of having more granular tranches.³⁵⁵

PG&E described the process it used to develop the tranches for the LOCTM risk model in a TURN data response.³⁵⁶ In developing the tranches for the LOCTM risk model, PG&E relied on information from its TIMP operational risk model, which contains detailed pipe characteristic and asset health information at the pipe segment level, including consequence information for leaks and ruptures. The tranches for the LOCTM risk model were developed based on fundamental industry knowledge and regulatory understanding regarding factors associated with leak and rupture loss of containment events and the potential impact of such events for the pipe segments in the TIMP model.³⁵⁷

Since PG&E's 2023 GRC application was submitted in June 2021, PG&E has worked to make the LOCTM risk model more granular and provided the results of an updated risk model to TURN.³⁵⁸ The tranche granularity for the updated LOCTM risk model increased from 4 to 24 tranches. These new tranches were chosen based on groups of assets with known risk distinctions and risk profile, using information from the TIMP model.

PG&E's risk analysis is continually evolving, and we are continuing to better align the TIMP operational risk model to the enterprise LOCTM risk model, make refinements in data application, and incorporate regulatory changes from the ongoing Risk-Based Decision-Making Framework OIR (R.20-07-013). Risk scores and RSEs for the mitigation and control programs will continue to evolve accordingly.³⁵⁹

³⁵⁵ PG&E-16-E, p. 3-5, line 24 to p. 3-6, line 9.

³⁵⁶ PG&E-16-E, PG&E's response to Data Request TURN_066_Q01Rev01Supp01, dated 3/23/22, pp. AppA-2 to AppA-13.

³⁵⁷ PG&E-16-E, p. 3-4, lines 8-17.

³⁵⁸ PG&E-16-E, PG&E's response to Data Request TURN_066_Q01Rev01Supp01, dated 3/23/22, pp. AppA-2 to AppA-13.

³⁵⁹ *Id.*

3.2.2.2 Reducing Gas Operations' Forecast Based Solely On RSE Scores Is Not Justified

While the RSE scores for many gas programs appear to be relatively lower than for other risks such as for Wildfire, this does not mean that PG&E should not pursue gas safety and reliability programs as continuing risk in the gas system requires ongoing mitigation and control programs to manage that risk. As discussed by PG&E Witness Sumeet Singh³⁶⁰ and in Sections 2.2 and 2.3 of this opening brief, PG&E's risk model development and RSEs are still evolving and such conclusions are premature.³⁶¹ Moreover, PG&E's Gas Operations forecasts are based on justifications independent of relative RSE scores, as explained in more detail throughout Section 3 of this opening brief when we respond to TURN's proposals to eliminate or drastically reduce specific programs solely because of RSE scores. The RAMP risk model analysis is still evolving, as PG&E explains at length in its rebuttal testimony, and thus cancelling or downsizing programs based solely on RSE scores is not warranted at this time.³⁶²

TURN argues that numerous Gas Distribution, Gas Transmission, Gas Facilities, and Gas Operations programs, are not cost effective due to low RSE scores and benefit-cost ratios. For the reasons stated above, this argument lacks merit. In addition, as discussed in Section 2.3, the Commission has not yet approved a methodology for converting RSE scores into benefit-cost ratios as TURN purports to do. Finally, PG&E's testimony includes extensive operational justification for our programs and forecasts other than RSE scores.³⁶³

3.2.2.3 PG&E Responded Appropriately To SPD's Comments On PG&E's 2020 RAMP Report

TURN incorrectly claims that "[t]he staff recommended that PG&E use the same density-based tranches as it did for the LOCTM and LOCDM risks, [but that] PG&E did not

³⁶⁰ PG&E-15-E, Ch. 1, Section C.4.

³⁶¹ PG&E-16-E, p. 3-6, lines 16-22.

³⁶² PG&E-16-E, p. 3-6, line 26 to p. 3-7, line 2.

³⁶³ PG&E-16-E, p. 3-7, lines 5-18.

make this change for the GRC.”³⁶⁴ PG&E responded to SPD’s comments on PG&E’s 2020 RAMP Report in a workpaper for Exhibit PG&E-02 Chapter 1, Enterprise and Operational Risk Management Program.”³⁶⁵ PG&E addressed the specific SPD staff comment referred to by TURN, stating:

PG&E is adding additional outcomes to its Large Overpressure Event Downstream of Gas Measurement & Control Facility risk model to account for different properties associated with downstream pipe assets. PG&E determined that additional outcomes, as opposed to tranches, were more appropriate for the overpressure risk model since the likelihood of the risk event is driven by the station, not the properties of the downstream pipe.³⁶⁶

3.2.2.4 An RSE Was Not Required To Be Computed For The Meter Protection Program

TURN’s final argument related to Gas Operations’ risk management is that PG&E was unable to provide an RSE for the Meter Protection Program as it relates to the Loss of Containment on Gas Customer Connected Equipment risk, and that “[t]he CPUC should require PG&E to provide the risk estimate for the next GRC.”³⁶⁷ As explained in PG&E’s testimony, however, an RSE was not required to be computed for the Meter Protection Program as it relates to the Loss of Containment on Gas Customer Connected Equipment risk.³⁶⁸

3.3 Asset Family – Distribution Mains and Services

This Distribution Mains and Services asset family includes 43,000 miles of gas distribution mains and provides natural gas service to approximately 4.6 million residential, commercial, and industrial customers.³⁶⁹ Distribution Mains and Services includes assets such

³⁶⁴ TURN-02, p. 113, lines 7-10 (fns. omitted).

³⁶⁵ PG&E-02, WP 1-12 to WP 1-67.

³⁶⁶ PG&E-02, WP 1-44, line 197. See also PG&E-03, p. 3-26, lines 16-21, discussing the risk model change.

³⁶⁷ TURN-06, p. 33, lines 16-18.

³⁶⁸ PG&E-03, p. 3-33, line 22 to p. 3-34, line 3; WP 3-33, line 1; see also PG&E-16-E, p. 3-8, lines 12-23.

³⁶⁹ PG&E-03, p. 4-7, lines 28-31.

as distribution pipelines, risers, pits and vaults, valves and ancillary services (*e.g.*, cathodic protection).³⁷⁰ The programs in this asset family include PG&E's Distribution Integrity Management Program (DIMP), distribution pipeline replacement programs, distribution service replacement programs, and other gas distribution reliability work.³⁷¹

PG&E's Corrected Forecast for GD expense is \$62.019 million in 2023.³⁷² PG&E's JCE forecast is \$63.732 million in 2023.³⁷³

PG&E's Corrected Forecast for GD capital is \$628.827 million in 2021, \$737.104 million in 2022, \$786.453 million in 2023, \$831.908 million in 2024, \$877.428 million in 2025, and \$924.601 million in 2026.³⁷⁴ PG&E's JCE forecast for GD capital is \$660.971 million in 2021, \$815.601 million in 2022, \$880.899 million in 2023, \$907.348 million in 2024, \$934.676 million in 2025, and \$961.216 million in 2026.³⁷⁵

Of the 7 expense MATs related to Distribution Mains and Service, only 2 are disputed. Similarly, for the 10 gas distribution capital MATs, only 3 are disputed. The undisputed programs, associated MATs, and corresponding expense and capital forecasts are identified in Appendix A. The disputed programs and associated MATs, include:

³⁷⁰ PG&E-03, p. 4-8, lines 7-9.

³⁷¹ PG&E-03, p. 4-1, lines 10-14.

³⁷² PG&E-16-E, p. 4-3, Table 4-1, line 8.

³⁷³ PG&E-64, p. 3-1, Table 3A-1, lines 1 and 2.

³⁷⁴ PG&E-16-E, p. 4-59, Table 4-6, line 12 (2021 and 2022) and PG&E-3-ES, p. v, which reflects PG&E's rebuttal forecast updated with corrected escalation factors (2023).

³⁷⁵ PG&E-64, p. 3-6, Table 3B-1, lines 1-2 (2023); p. 3-10, Table 3B-2, lines 1-2 (2022); and p. 3-14, Table 3B-3, lines 1-2 (2021). Forecasts for 2024-2026 are not included in the JCE but are provided here for reference.

**TABLE 3-3
SUMMARY OF ISSUES ADDRESSED IN SECTION 3.3**

Section	Disputed Program	Impacted MATs
3.3.1	Fitting Mitigation Program	Expense (MAT JQG)
3.3.2	Cross Bore Program	Expense (MAT JQK)
3.3.3	Gas Pipeline Replacement Program (GPRP)	Capital (MAT 14A)
3.3.4	Plastic Pipe Replacement Program	Capital (MAT 14D)
3.3.5	Reliability Service Replacement Program	Capital (MAT 50B)

In the remainder of this Section 3.3, we address the disputed distribution mains and services programs.

3.3.1 Fitting Mitigation Program – Expense

Over a 10-year period, PG&E proposes mitigating 22,000 potentially defective plastic fittings installed on PG&E’s gas distribution system through the Fitting Mitigation Program.³⁷⁶ The fittings, that connect service lines to main gas distribution lines, are subject to potential failure on the service-side piping caused by an incomplete fusion between fitting components during manufacturing. The potential for failure of these fittings was identified after elevated failure rates were observed through PG&E’s extensive testing of quarantined fittings.³⁷⁷

PG&E plans to mitigate approximately 2,200 units per year starting in 2023 by field locating, excavating, and mitigating these fittings. The goal is to complete mitigation of these fittings in 10 years. This population of substandard plastic fittings with a manufacturer defect was installed between 2016 and 2017. By mitigating this population over 10 years between 2023 and 2032, the oldest fittings in the last year of this mitigation will have been in service for 16 years (2016-2032), which provides a nearly 50 percent margin of safety to the estimated 29-year Mean Time to Failure (MTTF).³⁷⁸

³⁷⁶ PG&E-03, p. 4-19, line 1 to p. 4-21, line 10.

³⁷⁷ PG&E-16-E, p. 4-7, line 16-25.

³⁷⁸ PG&E-16-E, p. 4-7, line 31 to p. 4-8 line 9.

TURN proposes a 50 percent reduction (\$8.0 million)³⁷⁹ by extending the program’s mitigation pace from 10 to 20 years.³⁸⁰ Cal Advocates proposes no funding for the program.³⁸¹ The parties’ proposals are:

TABLE 3-4
FITTING MITIGATION PROGRAM (MAT JQG): PG&E’S EXPENSE FORECAST AND
PARTIES RECOMMENDED REDUCTIONS (\$000s)^(a)

Party	2020 Rec.	2021	2022	2023
PG&E	\$691	\$1,018	\$1,037	\$15,923 ^(b)
Cal Advocates				\$(15,923)
TURN				\$(7,962)

(a) PG&E-16-E, p. 4-3, Table 4-1, line 5 and p. 4-58, Table 4-5, line 5.
(b) PG&E’s 2023 forecast is approximately \$15.2 million higher than 2020 recorded. The 2023 forecast increase is driven by a change in program scope from mechanical fitting replacement to plastic fusion fitting replacement. PG&E-03, p. 4-24, lines 11-17.

In the remainder of Section 3.3.1, PG&E addresses: (1) the pace of the Fittings Mitigation Program; (2) the program’s unit costs; (3) Cal Advocates’ argument that the Fitting Mitigation Program was previously funded; and (4) why costs associated manufacturer defects should be included in rates.

3.3.1.1 The Pace of the Fittings Mitigation Program Is Appropriate

PG&E’s forecast to mitigate substandard fittings over 10 years reflects a proactive approach to prevent these fittings from reaching an age where failures will occur more frequently. TURN claims a slower pace is justified due to a low RSE score, and correspondingly, a low benefit-cost ratio and that the future rate of leaks from the substandard fittings is unknown.³⁸² However, slowing the pace to 20 years, as TURN proposes, would

³⁷⁹ TURN-06, p. 30, lines 1-6.

³⁸⁰ TURN also claims “PG&E’s goal is to remove the affected fittings within the [mean time to failure for] plastic ... fittings, which is 29 years.” TURN-06, p. 29, lines 18-20. This assumption is incorrect. PG&E’s proposal is to mitigate these fittings by the time they reach 16 years of service, i.e., approximately half the MTTF of 29 years. See PG&E-16-E, p. 4-11, lines 6-8.

³⁸¹ CALPA-02, p. 4, lines 12-13.

³⁸² TURN-06, p. 29, lines 16-18.

likely increase both the failure rate and the potential for injury and property damage caused by gas migration and ignition from a loss of containment event.³⁸³

While PG&E may not be able to predict exactly when the fittings will fail, tests indicate a potential failure rate 14 times higher than fittings without the potential defect.³⁸⁴ Thus, it is reasonable to predict that these fittings will likely fail earlier than the expected life of a fitting without the defect. PG&E's proposed mitigation pace of 10-years between 2023 and 2032 results in the oldest substandard fittings with a manufacturer defect being in service for 16 years, and most substandard fittings being mitigated before they reach half of the mean time to failure of 29 years.³⁸⁵

TURN's proposal to slow the pace of the program based on RSE scores and benefit cost ratios is based on a flawed analysis, as explained in detail in Sections 2.3 and 3.2.2.2 of this opening brief. TURN ignores the significant failure rates of the defective fittings identified through lab testing and the estimated mean time to failure of 29 years. Under these circumstances, a proactive risk-informed approach to mitigate the fittings by the time they reach half of their estimated life is more reasonable and should be approved.

3.3.1.2 PG&E's Unit Cost is Reasonable

PG&E designed and implemented a pilot program from 2020 to 2022 to provide information needed to support implementation of the Fitting Mitigations Program. This pilot program was completed after PG&E filed the initial 2023 GRC application.³⁸⁶ Cal Advocates argues that since PG&E had not completed its pilot program when it submitted its GRC request,

³⁸³ PG&E-16-E, p. 4-10, line 29 to p. 4-11 line 2.

³⁸⁴ PG&E-03, p. 4-19, line 29 to p. 4-20, line 3.

³⁸⁵ PG&E-16-E, PG&E's response to Data Request CalAdvocates_226-Q03, dated 2/1/22, p. AppA-14.

³⁸⁶ PG&E-16-E, p. 4-13, lines 1-3.

PG&E did not have sufficient information to propose a program or establish the unit costs.³⁸⁷ However, PG&E developed its 2023 unit cost forecast of \$7,294 with the most comprehensive information available at that time, including vendor bids and engineering analysis to complete the pilot program scope of work. PG&E's forecasting methodology is described in opening testimony, data requests responses, and rebuttal testimony.³⁸⁸ The unit forecast is based on a reasonable methodology, information and data. Cal Advocates has not shown otherwise.

3.3.1.3 Mitigation of the Plastic Fusion Fittings was not Previously Funded

Cal Advocates' incorrectly argues that PG&E received funding to mitigate plastic fittings as part of the 2020 GRC in the Mechanical Fitting Program and thus PG&E should not be able to recover the costs in this proceeding.³⁸⁹ The scope of work for the Fitting Mitigation Program is different from the scope of the Mechanical Fitting Program addressed in the 2020 GRC and targets a separate and distinct fitting from that addressed in the 2020 GRC.³⁹⁰ The current Fitting Mitigation Program targets plastic fusion fittings with a high failure rate due to manufacturing defects.³⁹¹ These fittings were not addressed in the 2020 GRC and should be fully funded.

3.3.1.4 The Fitting Mitigation Program Should Be Funded

Finally, Cal Advocates argues that customers should not be responsible for the mitigation costs of the defective plastic fittings caused by a manufacturing defect. However, it is appropriate and consistent with past Commission practice to fund remediation of manufacturing defects discovered in products.

³⁸⁷ CALPA-02, p. 5, line 19 to p.6, line 5.

³⁸⁸ PG&E-16-E, p. 4-13, lines 4-21.

³⁸⁹ CALPA-02, p. 6, lines 19-21.

³⁹⁰ PG&E-03, p. 4-19, lines 2-20.

³⁹¹ PG&E-03, p. 4-19, lines 21-24.

First, PG&E took reasonable actions to minimize the risks associated with the plastic fusion manufacturing defect before and after it was discovered. PG&E procured the fittings from a reputable national company, applied a robust Supplier Quality Assurance program based on statistical sampling, and quarantined all potentially defective fittings in inventory. We also pursued a rigorous testing program, determined the number and location of products that had been installed in the field, and engaged with the manufacturer to determine the extent of the manufacturing issue and to receive assurances that the issue did not extend further to other plastic fitting products or vintages. And we pursued our legal remedies against the supplier and settled our warranty claim in bankruptcy.³⁹²

Second, the Commission has approved customer funding for mitigation of similar manufacturing and material quality issues. For example, PG&E's Plastic Pipe Replacement Program (MAT 14D) addresses risks and potential failure related to pre-1985 Aldyl-A plastic pipe which has a susceptibility to slow crack growth.³⁹³ Other examples include funding for the Mechanical Fitting Replacement Program (MAT JQG) in the 2020 GRC that focused on targeted removal of a certain failure-prone fitting with stainless-steel rings used to fasten fittings to the pipe.³⁹⁴

³⁹² PG&E's mitigations activities are described in PG&E-16-E, p. 4-8, line 17 to p. 4-9 line 11. The recovery amount represented by the bankruptcy resolution of the warranty claim was \$225,000 for defective products, including the defective plastic fusion fittings. (Tr. Vol. 5, 887:13-17, PG&E/ Kerans.) This amount of recovery was not of sufficiently significant value or volume to change PG&E's forecast. See Tr. Vol. 5, 884:3-5, PG&E/ Kerans.

³⁹³ 2020 GRC Settlement Agreement Section 2.2.2 approved in D.20-12-005, p. 3.

³⁹⁴ This was a dedicated mitigation program under MAT JQG that was funded in the 2020 GRC. As stated in Section 2.2.1 of the 2020 GRC Settlement Agreement approved by the Commission in D. 20-12-005, "Unless otherwise addressed, the Settling Parties agree to PG&E's Gas Distribution forecasts and other proposals." (D.20-12-005, Settlement Agreement, p. 3.) The Mechanical Fitting Replacement program, MAT JQG, was forecast in Exhibit HE-10 and was not adjusted by the Settlement Agreement. (A.18-12-009, HE-10, Exhibit (PG&E-3), p. 4-25, lines 1-20 and p. 4-33, lines 8-12.)

3.3.2 Cross Bore Program – Expense (MAT JQK)

A cross bore is an inadvertent placement of an underground utility through a wastewater or storm drain system during trenchless construction. Cross bores pose a risk as they can result in a gas leak into the sewer system if damaged during mechanical sewer cleaning operations. Cross bores are a concern for gas utility operators nationwide and are identified as presenting a high risk to public and employee safety. This program utilizes video equipment to inspect wastewater lines and laterals for potential cross bore situations. Any cross bores identified from the inspections are repaired.³⁹⁵ Since 2012, PG&E has identified and mitigated over 800 cross bores.³⁹⁶

PG&E is targeting to substantially complete the Cross Bore Program in San Francisco by the end of 2022 and focus in the GRC 2023 cycle on the approximately 800,000 inspections remaining outside of San Francisco. PG&E's 2023 forecast for the Cross Bore Program is to execute 45,000 inspections annually at a cost of \$753 per unit (inspection) with a 2023 forecast of \$33.9 million.³⁹⁷ TURN, the only party to object to this program forecast, proposes a 62% reduction:

TABLE 3-5
CROSS BORE PROGRAM (MAT JQK): PG&E'S EXPENSE FORECAST AND
RECOMMENDED REDUCTIONS (\$000s)^(a)

Party	2020 Rec.	2021	2022	2023
PG&E	\$31,752	\$30,585	\$52,185	\$33,907
TURN				\$(20,767)

(a) PG&E-16-E, p. 4-58, Table 4-5, line 6; PG&E-64, p. JCE 3-7.

TURN's proposes a reduced inspection pace (19,313 inspections per year instead of 45,000 per year) and a reduced unit cost (\$680 per unit instead of \$753).³⁹⁸ TURN claims:

³⁹⁵ PG&E-16-E, p. 4-16, lines 18-25. See also PG&E-03, p. 4-13, line 13 to p. 4-18.

³⁹⁶ PG&E-16-E, p. 4-16, line 32 to p. 4-17, line 1.

³⁹⁷ PG&E-03, WP 4-9, lines 1-3.

³⁹⁸ Tr. Vol. 13, 2433:4-7 TURN/Sugar.

(1) the relative risk of cross bores outside of San Francisco is much lower than in San Francisco, resulting in a low RSE score;³⁹⁹ (2) the declining cross bore find rate greatly increases the cost of the Cross Bore Program per cross bore found;⁴⁰⁰ and (3) PG&E should have utilized a different methodology for its unit cost forecast.⁴⁰¹ These three arguments are addressed below.

3.3.2.1 Cross Bores Outside San Francisco Pose a Significant Risk

TURN asserts that the risk of cross bores outside of San Francisco is not significant enough to justify the Cross Bore Program. TURN does not dispute that a cross bore, whether it occurs in or outside San Francisco, creates a significant safety risk. TURN's recommended reduced pace is inadequate to address this risk.

PG&E estimates that it has approximately 800,000 cross bore inspections remaining.⁴⁰² At TURN's recommended pace of 19,313 inspections per year, these inspections would take 41 years to complete. This is an unacceptably slow pace of remediation of the approximately 650 cross bores that would be found at today's estimated find rate ($800,000 \times 0.81 \text{ finds per } 1,000 = 648$). PG&E's proposed pace of 45,000 inspections per year would complete the remaining inspections in approximately 18 years ($800,000/45,000 = 17.8$). Moreover, PG&E's proposed pace of 45,000 inspections per year is consistent with the pace approved by the Commission for this program and within the execution capability of PG&E's cross bore inspection program resources.⁴⁰³ Given the significant number of potential cross bores remaining on PG&E's system, it is not justified to dismantle and shrink this program as TURN proposes. TURN's

³⁹⁹ TURN-06, p. 38, lines 10-12. See also TURN-02, p. 88, line 5 to p. 89, line 2.

⁴⁰⁰ TURN-06, p. 36, lines 3-5.

⁴⁰¹ TURN-06, p. 38, lines 14-19.

⁴⁰² PG&E-16-E, p. 4-17, lines 1-4.

⁴⁰³ PG&E-16-E, p. 4-19, lines 29-31.

reliance on the RSE score for this program as the sole reason to delay these safety inspections is also not warranted in light of the evolving nature of the RAMP process.⁴⁰⁴

3.3.2.2 The Rate of Cross Bore Finds

TURN argues that since the cross bore find rate per 1,000 inspections has declined from 7.74 in 2013 to 0.81 in 2021, the program should be reduced because the “expected benefit of each inspection” has declined.⁴⁰⁵ However, each cross bore located and mitigated reduces the likelihood of a catastrophic event, where gas could migrate into customer homes via the sewer, resulting in an explosion of a single or multiple homes in the affected area. PG&E has experienced seven loss of containment events as a result of cross bores from 2016 to present, *all of which have occurred outside of San Francisco*.⁴⁰⁶ Even at the rate of 0.81 finds per 1,000 inspections, PG&E can expect to find and mitigate 36 cross bores per year (45,000 inspections x 0.81 finds per 1,000) over the 4-year GRC forecast, each of which could have catastrophic consequences if not addressed.

3.3.2.3 PG&E’s Unit Cost Forecast is Reasonable

PG&E used a three-year average (2017-2019) of recorded spend and recorded units to develop the Cross Bore Program unit cost forecast which accurately estimates the cost to perform an inspection.⁴⁰⁷ During the 2017-2019 timeframe, 12% of PG&E’s inspections were in San Francisco (15,017) and 88% were outside San Francisco (109,845).⁴⁰⁸ PG&E expects to

⁴⁰⁴ As discussed in PG&E’s Enterprise and Operational Risk Management rebuttal testimony (Exhibit PG&E-15, Ch. 1) that addresses TURN’s use of RSE scores and Benefit Cost Calculations to reach cost effectiveness conclusions about PG&E’s programs, the RAMP modelling process is evolving and is not sufficiently mature to support funding decisions. See Section 2.3 of this brief.

⁴⁰⁵ TURN-06, p. 36, lines 3-5.

⁴⁰⁶ PG&E-16-E, p. 4-19, lines 4-10.

⁴⁰⁷ PG&E-03, WP 4-9, lines 12-18.

⁴⁰⁸ PG&E-16-E, PG&E’s response to Data Request TURN_194-Q001Rev01, dated 6/9/22, pp. AppA-18 to AppA-19.

encounter a small population of difficult inspections outside of San Francisco each year, similar to those encountered in San Francisco. Thus, PG&E factored into its unit cost of \$753 per inspection an assumption that 12 percent of the more complex inspections would occur annually outside of San Francisco.⁴⁰⁹ This is a reasonable and prudent approach to calculating future inspection costs outside San Francisco.

TURN based its unit cost on a three-year average of the costs and units for non-San Francisco specific units (2017-2019) with escalation.⁴¹⁰ This calculation yields a 2023 unit cost of \$680.⁴¹¹ This methodology is flawed because it does not take into account PG&E's estimate that 12% of the inspections will be more difficult and expensive. TURN's calculation therefore understates the cost of cross bore inspections.

3.3.3 Gas Pipeline Replacement Program

The GPRP (MAT 14A) is focused on deactivating higher risk steel distribution pipe, including pre-1941 steel pipe, and bare or non-cathodically protected steel pipe.⁴¹² The forecast for GPRP is to replace 37.1, 39.3, 41.4, and 43.5 miles in 2023, 2024, 2025, and 2026, respectively, using a federal code compliant operational risk model to replace the highest priority steel pipe for a total of approximately 161 miles during the GRC period.⁴¹³ The annual increase in main replacement units was determined by linearly increasing from the 2020 GRC imputed units of 35 miles in 2022 to 52 miles in 2030. This supports PG&E's asset management goal to achieve a steady-state combined replacement rate of 260 miles of plastic (MAT 14D) and steel

⁴⁰⁹ PG&E-03, WP 4-9, line 18.

⁴¹⁰ PG&E-16-E, p. 4-21, lines 25-28.

⁴¹¹ Tr. Vol. 13, 2433:4-7 TURN/Sugar.

⁴¹² PG&E-03, p. 4-29, line 9 to p. 4-30, line 22.

⁴¹³ PG&E-16-E, p. 4-31, lines 12-15.

(MAT 14A) main pipe per year by 2030.⁴¹⁴ The unit cost forecast is based on a three-year average of recorded costs (2017-2019) with escalation.⁴¹⁵ TURN and Cal Advocates addressed the GPRP and propose:

TABLE 3-6
GAS PIPELINE REPLACEMENT PROGRAM (MAT 14A): PG&E’S CAPITAL FORECAST
AND PARTIES RECOMMENDED REDUCTIONS (\$000s)^(a)

Party	2020 Rec.	2021	2022	2023	2024	2025	2026
PG&E	\$113,385	\$94,347	\$115,413	\$151,729	\$164,424	\$177,312	\$190,706
Cal Advocates ^(b)				\$(37,569)			
TURN				\$(130,623)	\$(142,997)	\$(155,826)	\$(169,227)
(a) PG&E-16-E, p. 4-59, Table 4-6, line 1 (2020-2022 recorded and forecast amounts); PG&E-3-ES, p. v (2023-2026 forecasts); PG&E-16-E, p. 4-4, Table 4-2, line 1 (TURN’s recommendation). (b) PG&E discusses how it estimated Cal Advocates’ recommended reduction in rebuttal testimony. See PG&E-16-E, p. 4-31, line 24 to p. 4-32, line 12.							

TURN recommends that PG&E’s funding be reduced to five miles of steel pipe replacement per year “and an additional 10 miles per year of non-cathodically protected pipe needing replacement within 10 years.”⁴¹⁶ TURN recommends 60 miles over the four-year 2023 GRC cycle (2023-2026) instead of the 161 miles PG&E proposes over the same timeframe, a reduction of 101 miles. TURN proposes a reduction of approximately \$429.5 million to PG&E’s 2023-2026 forecast of \$683.3 million.⁴¹⁷ To support this drastic reduction to PG&E’s forecast, TURN claims that: (1) the program has a low RSE score and cost-benefit ratio;⁴¹⁸ and (2) PG&E should instead focus on replacing steel pipe installed before 1924.⁴¹⁹ Cal Advocates

⁴¹⁴ The overall rate of plastic and steel main pipeline replacement is explained in testimony. See PG&E-03, p. 4-28, line 11 to p. 4-29, line 8. Table 4-11, p. 4-29 shows the MAT 14A and 14D distribution main replacement rate from 2016 to 2030.

⁴¹⁵ PG&E-03, WP 4-38.

⁴¹⁶ TURN-06, p. 25, lines 8-11.

⁴¹⁷ TURN-06, p. 25, Table 14.

⁴¹⁸ TURN-02, p. 74, line 10 to p. 87, line 12.

⁴¹⁹ TURN-06, p. 23, lines 4-8; p. 25, lines 6-11.

proposes reducing PG&E’s 2023 steel pipe replacement mileage from 37.1 miles to 27.9 miles.⁴²⁰ Cal Advocates argues that: (1) PG&E did not identify the segments of pipelines; and (2) PG&E’s request is higher than the base year level and the 2019 level.⁴²¹ Neither TURN nor Cal Advocates dispute PG&E’s unit cost forecast for the GPRP. Their arguments are addressed below.

3.3.3.1 PG&E Appropriately Prioritizes Steel Pipe Replacement

TURN’s recommendation that PG&E focus on pre-1924 steel pipe should be rejected. PG&E should instead continue to replace the riskiest pipe based on its DIMP risk model regardless of the installation year of the pipe.

Utilizing the DIMP risk model,⁴²² the GPRP prioritizes pipe segments based on the relative risk of each pipe segment. The risk ranking is based on a methodology that considers pipe age, leak history, cathodic protection, coating, seismic activities, and population proximity.⁴²³ In addition, PG&E’s DIMP risk model incorporates unitless modifiers for items such as migration, pressure, and population density and utilizes likelihood of failure and consequence of failure to determine risk of failure, in accordance with industry standard risk methodology.⁴²⁴

TURN recommends that PG&E focus the GPRP on “the most leak prone” pre-1924 pipe.⁴²⁵ However, to evaluate pipe solely based on leak rate and vintage is inconsistent with

⁴²⁰ CALPA-02, p. 12, Table 2-10 shows Cal Advocates’ corresponding funding proposals.

⁴²¹ CALPA-02, p. 14, lines 6-12.

⁴²² PG&E-16-E, p. 4-27, lines 23-33. The DIMP risk model is compliant with Code of Federal Regulations (CFR) Title 49, Transportation, Part 192—Transportation of Natural and Other Gas by Pipeline: Minimum Federal Safety Standards, Subpart P, “Gas Distribution Pipeline Integrity Management,” to identify, down to the segment level, pipeline replacement projects under the GPRP program and doesn’t rely solely on asset age or leaks per mile.

⁴²³ PG&E-03, p. 4-30, lines 3-6.

⁴²⁴ PG&E-16-E, p. 4-28, lines 23-27.

⁴²⁵ TURN-06, p. 23, lines 4-8; p. 25, lines 6-11.

Federal regulations. As described above, PG&E's risk model evaluates a series of factors as required by regulation, including pipe age and leak history. While it may be true that steel pipe installed prior to 1924 has a higher leak rate than the pipe installed from 1924-1940,⁴²⁶ a single leak on pre-1924 pipe may not carry as much risk as one or more leaks on a post-1924 pipe. The DIMP risk model takes into consideration the eight federal code required threats along with other factors to evaluate the pipe.⁴²⁷ TURN's recommendation, on the other hand, does not take into account the other required factors, including the consequences of failure. TURN's recommendation to focus on pre-1924 pipe would not lead to the replacement of the highest risk pipe.

TURN concedes that its recommendation to "focus on pre-24 pipe" is not intended to limit PG&E to replacing pre-1924 pipe, acknowledging that PG&E should apply its DIMP risk model to replace the highest risk pipe with the funding it receives, even if that pipe is post-1923 pipe.⁴²⁸ TURN's recommendation simply amounts to a proposal to replace a dramatically lower amount of pipe per year. The risks of shrinking the program in this way are discussed in the next section.

3.3.3.2 TURN's Proposed Reduction in Pace Is Imprudent

PG&E's forecast to replace an average of 40 miles of vintage steel pipe per year is intended to achieve a steady-state replacement rate of 260 miles main pipe per year by 2030.⁴²⁹ Reaching this pace of replacement, including vintage steel and plastic pipe, is necessary to

⁴²⁶ This higher leak rate per mile is due to the small mileage of pipe remaining per year in this time period. The amount of steel pipe remaining prior to 1924 is approximately 53-times less than the pipe remaining from 1924-1940. See PG&E-16-E, p. 4-26, lines 17-19.

⁴²⁷ PG&E-16-E, p. 4-27, lines 1-4.

⁴²⁸ Tr. Vol. 13, 2447:8-15, TURN/Sugar.

⁴²⁹ PG&E-16-E, PG&E's response to Data Request ED_014-Q01Supp01, dated 12/8/21, and ED_014-Q01Atch05PUBLIC, pp. AppA-70 to AppA-140.

comply with PG&E's Asset Management Plan's⁴³⁰ strategic objective of limiting asset age to 100 years.⁴³¹ PG&E's proactive replacement of distribution pipelines is a prudent approach to managing the pipeline asset risk before the pipelines reach end of life and fail at an unmanageable rate that makes it infeasible from a resource perspective to repair or replace failing assets. Furthermore, PG&E's proactive replacement addresses the mitigation of significant incidents that could result from increasing volumes of aging pipe that will approach 100 years in-service or older.⁴³²

PG&E has 1,730 miles of pre-1941 vintage steel distribution pipe.⁴³³ This steel pipe has already been in the ground for longer than 80 years. If our proposed pace of replacement is not adopted, we will not be able to achieve steady-state replacement of this pipe with the 100-year asset life. TURN's proposed replacement rate of 15 miles per year, compared to our proposal of 40 miles per year, virtually guarantees that steady-state replacement will never be achieved and aging, deteriorating vintage steel pipe will remain in the ground.

In both the 2017 and 2020 GRCs the Commission adopted a requirement that:

PG&E should strive for reasonable rates of steady state replacement, consistent with risk-informed decision making, for crucial operating equipment necessary to provide safe and reliable service. Such steady state replacement includes proactive replacement of an asset prior to in-service failure when warranted based on risk and engineering analysis that considers vintage, material properties, environmental conditions, life-extension maintenance practices, and any other relevant parameters. PG&E should strive to reduce post-failure replacement for assets where failure can result in unreasonable safety or cost impacts.⁴³⁴

⁴³⁰ PG&E's 2021 Gas Distribution Mains and Services Asset Management Plan, PG&E-16-E, pp. AppA-70 to AppA-140, presents the asset inventory, an assessment of condition and overview of risks to the DMS assets, and the long term strategic objectives and key programs in progress to manage these risks. PG&E's Asset Management Plans are also described in PG&E's Gas Safety Plan that is submitted annually pursuant to PU Code 961 and 963.

⁴³¹ See PG&E-16-E, p. AppA-120, Table 16.

⁴³² PG&E-16-E, p. 4-33, lines 21-27.

⁴³³ PG&E-16-E, PG&E's response to Data Request TURN_048_Q001Atch01, dated 11/16/21, p. AppA-27.

⁴³⁴ 2020 General Rate Case Settlement Agreement, Section 5.1, approved in D.20-12-005, pp. 35-36.

Pursuant to this requirement, in Chapter 21 of PG&E’s June 30, 2020 RAMP report, PG&E describes its risk-informed approach to pro-active asset replacement for each of its operating lines of business: Gas Operations, Electric Operations, and Power Generation.⁴³⁵ TURN’s reduced rate of vintage steel pipe replacement is wholly at odds with the principle of steady state replacement adopted by the Commission.

Finally, TURN’s reliance on RSE scores to curtail the vintage steel pipe replacement program is misplaced. Exclusive reliance on RSE scores to defund this program is not warranted in light of the evolving nature of the RAMP process. Moreover, as explained in Sections 2.3 and 3.2.2.2 of this opening brief, TURN’s RSE analysis and benefit-cost ratio approach is fundamentally flawed.

3.3.3.3 PG&E Has Supported its GPRP Proposal

Cal Advocates’ recommendation to reduce the steel pipe replacement forecast for 2023 from PG&E’s forecast of 37.1 miles to 27.9 miles is based on two arguments. First, Cal Advocates argues that the program should be reduced because PG&E had not identified *by October 2021* the specific pipeline projects that it would perform *in 2023*. PG&E acknowledged in a data request dated October 2, 2021 that the 2023 projects for MAT 14A had not been identified.⁴³⁶ However, PG&E also explained that it had not fully completed its project development process for GPRP, MAT 14A, as defined in PG&E Utility Procedure TD-4802P-01 “Distribution Main Replacement Program Management,” Section 2.1,⁴³⁷ to determine an optimal book of work for 2023. PG&E uses the DIMP model to develop its workplan for each year based on this risk ranking, and projects are planned and executed accordingly.⁴³⁸ In this

⁴³⁵ PG&E-02, p. WP 1-869 to WP 1-880.

⁴³⁶ PG&E’s response to CalAdv_063-Q02, subpart c, cited by Cal Advocates at CALPA-02, p. 14, lines 8-9.

⁴³⁷ PG&E-03, WP 4-96 to WP 4-98, Utility Procedure: TD-4802P-01, Rev. 0a (Dec. 18, 2019), Distribution Main Replacement Program Management.

⁴³⁸ PG&E-16-E, p. 4-32, line 31 to p 4-33, line 10.

way, PG&E ensures that the funding is used to mitigate the greatest risk.⁴³⁹ Cal Advocates appears to fault PG&E for following its analytical work development processes. This is not a reasonable justification for a \$37.6 million reduction.

Second, Cal Advocates notes that “PG&E’s request of 37.1 miles [in 2023] is 52 percent higher than the base year level and is 86 percent higher than the 2019 level.”⁴⁴⁰ However, as explained above in Section 3.3.3.2, the increase in steel main replacement that PG&E is requesting is necessary to achieve a steady-state replacement rate of 260 miles of pre-1985 main pipe per year by 2030 consistent with the principle of steady state replacement of assets adopted by the Commission. PG&E’s proactive replacement of distribution pipelines is a prudent approach to managing the pipeline asset risk before the pipelines reach end of life and fail at an unmanageable rate that makes it infeasible from a resources perspective to repair or replace failing assets.⁴⁴¹ Thus, the Commission should reject Cal Advocates’ recommended 2023 capital reduction.

3.3.4 Plastic Pipe Replacement Program – Capital (MAT 14D)

PG&E established the Plastic Pipe Replacement Program (MAT 14D) in 2012 to mitigate risks associated with leaks on Distribution Mains and Services (DMS) installed before 1985 with Aldyl-A plastic and similar plastic materials. Plastic materials of pre-1985 vintage have a susceptibility to slow crack growth when exposed to stress, such as tree roots, differential settlement, or rock impingement. The Plastic Pipe Replacement Program prioritizes plastic main replacement projects based on the relative risk of each pipe segment.⁴⁴²

⁴³⁹ PG&E-16-E, PG&E’s response to Data Request CalAdvocates_063-Q01(b-c), dated 9/24/21 and CalAdvocates_063-Q01Atch01 to CalAdvocates_063-Q01Atch06, pp. AppA-142 to AppA-220.

⁴⁴⁰ CALPA-02, p. 14, lines 11-12.

⁴⁴¹ PG&E-16-E, p. 4-33, lines 21-24.

⁴⁴² The Plastic Pipe Replacement Program is more fully discussed in PG&E’s prepared testimony PG&E-03, p. 4-30, line 23 to p. 4-31, line 9.

PG&E’s unit forecast is to replace 170.4, 175.8, 181.1, and 186.5 miles in 2023, 2024, 2025, and 2026, respectively, for a total of approximately 714 miles. The annual increase in main replacement units was determined by linearly increasing from the 2020 GRC Settlement Agreement for 2022 units of 165 miles to 208 miles in 2030. This supports PG&E’s asset management goal to achieve a steady-state replacement rate of 260 miles of main replacement per year by 2030.⁴⁴³ The unit cost forecast is based on a three-year average of recorded costs (2017-2019) plus escalation. TURN, Cal Advocates, and AARP address the Plastic Pipeline Replacement Program and propose:

TABLE 3-7
PLASTIC PIPE REPLACEMENT PROGRAM (MAT 14D): PG&E’S CAPITAL FORECAST
AND PARTIES RECOMMENDED REDUCTIONS (\$000s)^(a)

Party	2020 Rec.	2021	2022	2023	2024	2025	2026
PG&E	\$286,112	\$448,350	\$533,634	\$522,344	\$552,293	\$582,276	\$613,345
Cal Advocates		\$(51,955)	\$(137,239)	\$(123,630)			
TURN				\$(348,417)	\$(369,043)	\$(390,240)	\$(412,290)
AARP				\$(109,697)	\$(140,482)	\$(172,119)	\$(205,030)
(a) PG&E-16-E, p. 4-59, Table 4-6, line 3 (2020-2022 recorded and forecast amounts); PG&E-3-ES, p. v (2023-2026 forecasts); PG&E-16, p. 4-4, Table 4-2, line 2 and p. 4-5, Table 4-2, line 2 (Parties’ recommendations).							

TURN’s proposes a two-thirds reduction to PG&E’s forecast, which corresponds to a two-thirds reduction in replacement program scope from pre-1985 plastic pipe to pre-1976 plastic pipe.⁴⁴⁴ TURN’s proposed funding level would limit PG&E to replacing an average of 59 miles per year and target replacement of all 2,045 miles of pre-1976 plastic pipe by 2058.⁴⁴⁵

⁴⁴³ The overall rate of plastic and steel main pipeline replacement is explained in testimony. See PG&E-03, p. 4-28, line 11 to p. 4-29, line 8. Table 4-11, p. 4-29, shows the MAT 14A and 14D distribution main replacement rate from 2016 to 2030. The proposed rate of replacement is consistent with PG&E’s Asset Management Plan, PG&E-16-E, pp. AppA-72 to AppA-140.

⁴⁴⁴ TURN-06, p. 21, lines 1-2.

⁴⁴⁵ PG&E-16-E, TURN’s response to PG&E Data Request PGE_TURN_009-Q01, dated 6/27/22, pp. AppA-63 to AppA-64.

TURN bases its proposed reduction on three arguments: (1) RSE scores;⁴⁴⁶ (2) PG&E should focus on plastic main installed in 1975 and earlier;⁴⁴⁷ and (3) PG&E’s proposal could result in avoidable stranded investments before the Commission has an opportunity to explore policies and local regulations related to cost equity, electrification and future gas demand.⁴⁴⁸

Cal Advocates’ proposed forecast reduction would allow replacement of 134.5 miles of pre-1985 plastic pipe in 2022 compared to PG&E’s 170.4 mile forecast.⁴⁴⁹ Cal Advocates argues that PG&E: (1) underperformed this program in the 2020-2022 period;⁴⁵⁰ (2) has not “demonstrated a record that supports an even higher estimate of pipeline replacement miles...”;⁴⁵¹ and (3) has not identified an increase to the risk level associated with pre-1985 plastic pipe or the segments already identified for 2021-2022.⁴⁵² Cal Advocates recommends that the 2023 forecast be based on 2021 recorded costs.⁴⁵³ Cal Advocates also recommends a forecast of \$396.4 million for 2021 and 2022 that is based on PG&E’s capital expenditures in 2021.⁴⁵⁴

AARP’s proposed reduction maintains the program’s funding at the average annual level that was approved in the 2020 GRC, which was \$410.3 million for 139 miles of pre-1985 plastic

⁴⁴⁶ TURN-06, p. 20, lines 14-16.

⁴⁴⁷ TURN-06, p. 13, lines 9-15 and p. 20, lines 21-24.

⁴⁴⁸ TURN-06, p. 8, line 21 to p. 9, line 4.

⁴⁴⁹ PG&E-16-E, p 4-42, lines 14-17.

⁴⁵⁰ CALPA-02, p. 11, lines 10-11.

⁴⁵¹ CALPA-02, p. 9, lines 23-25.

⁴⁵² CALPA-02, p. 10, lines 20-29.

⁴⁵³ CALPA-02, p.11, lines 13-19.

⁴⁵⁴ CALPA-02, p. 11, lines 13-14 and p. 12, Table 2-9.

main replacement per year.⁴⁵⁵ AARP also recommends a lower unit cost for this program.⁴⁵⁶ AARP argues: (1) the program’s requested replacement rate is “significantly higher” than the prior CPUC-approved replacement rate of 139 miles per year;⁴⁵⁷ (2) the risk level presented by Aldyl-A plastic pipe has not changed;⁴⁵⁸ (3) the program has a relatively low RSE score compared to undergrounding overhead electric lines;⁴⁵⁹ (4) “[i]t may make sense to pursue full electrification first in areas served by pre-1985 Aldyl-A pipe ... to avoid replacement costs”⁴⁶⁰; (5) in light of the potential decrease in the use of natural gas in the future “California should be taking actions which reduce, rather than accelerate, investments in natural gas infrastructure;”⁴⁶¹ and (6) the Commission should use a lower unit cost than proposed by PG&E.⁴⁶²

PG&E address the arguments raised by TURN, Cal Advocates, and AARP below.

3.3.4.1 All Pre-1985 Aldyl-A Pipe Is Subject to Cracking and Should Be Removed Before Its Expected Failure Date

PG&E’s proactive plastic pipe replacement program is in response to numerous studies, reports and industry advisories that plastic materials of pre-1985 vintage have a susceptibility to slow crack growth when exposed to stress, such as tree roots, differential settlement, or rock impingement. External stress can cause the initiation and propagation of cracks leading to leaks.

⁴⁵⁵ PG&E-16-E, p. 4-46, lines 5-9.

⁴⁵⁶ AARP-01, p. 40, lines 10-12.

⁴⁵⁷ AARP-01, p. 39, line 17 to p. 40, line 7.

⁴⁵⁸ AARP-01, p. 40, lines 1-3.

⁴⁵⁹ AARP-01, p. 41, lines 7-15.

⁴⁶⁰ AARP-01, p. 43, lines 9-11.

⁴⁶¹ AARP-01, p. 42, line 20 to p. 43, line 1.

⁴⁶² AARP-01, p. 43, lines 7-12.

PHMSA⁴⁶³ and the CPUC in a comprehensive 2014 study and report⁴⁶⁴ notified operators of the risks associated with vintage plastic pipelines and recommended mitigating these risks.

Key findings and recommendations of the CPUC’s 2014 Staff Report include:

- All vintages of plastic pipe manufactured prior to 1983 are susceptible to brittle-like cracking (by slow crack growth).⁴⁶⁵ This finding applies to both pre-1970 pipe and pipe manufactured from 1970-1983, contrary to TURN’s assertion that 1970-1983 pipe is “non-crack prone”.⁴⁶⁶ This finding is consistent with findings of the National Transportation Safety Board (NTSB)⁴⁶⁷ and PHMSA’s advisory bulletins.⁴⁶⁸ Two thirds of PG&E’s installed pre-1985 plastic pipe consists of 1970-1983 manufactured pipe.
- Failure rates on pre-1985 Aldyl-A will begin to rise in the coming decades. The Staff Report estimates that for pipe manufactured from 1970 to 1983 that is stressed by rock impingent, the pipe can be expected to fail due to crack development within 71 years (Medium Time To Failure, or MTTF).⁴⁶⁹ The Staff Report concludes that the projected peak failure years for PG&E’s installed pipe manufactured between 1970 and 1983 that is indented due to rock impingement are between 2050 and 2067.⁴⁷⁰ PG&E’s program is designed to proactively remove its vintage plastic pipes before they reach the projected peak failure years.
- Abrupt and rapid failure can be expected (and has occurred) due to slow crack growth on Aldyl A pipe. The Staff Report highlights the seriousness of Aldyl-A pipe failure “The danger associated with slow crack growth on Aldyl A is that

⁴⁶³ PG&E-03, WP 4-99 to WP 4-106, PHMSA’s Advisory Bulletins: ADB-99-02; ADB-02-07; and, ADB 07-01 (PHMSA Advisory Bulletins).

⁴⁶⁴ PG&E-03, WP 4-107 to WP 4-142, CPUC’s Hazard Analysis & Mitigation Report on Aldyl A Polyethylene Gas Pipelines in California (June 11, 2014) (Staff Report).

⁴⁶⁵ PG&E-03, Staff Report, WP 4-115, Table 1, showing that pre-1970 pipe has a “low” and 1970-1983 pipe has a “medium” relative resistance to slow crack growth.

⁴⁶⁶ TURN-06, p. 12, fn. 30. TURN’s witness John Sugar conceded on cross examination that 1970-1983 pipe is also crack prone. Tr. Vol. 13, 2454:3-8 and 2455:6-10, TURN/Sugar.

⁴⁶⁷ PG&E-03, Staff Report, WP 4-118.

⁴⁶⁸ PG&E-03, Staff Report, WP 4-118. The PHMSA Bulletins are found at PG&E-3, WP 4-99 to WP 4-106.

⁴⁶⁹ PG&E-03, Staff Report , WP 4-125, Table 4.

⁴⁷⁰ PG&E-03, Staff Report, WP 4-128, Table 7, last row. These failure dates are for pipe operated at 50 psi or greater that represents the operating condition of most of PG&E’s plastic pipe. See Staff Report, WP 4-127, Table 6, Rows 4 and 5.

although the failures develop slowly, when they do fail, they fail much more abruptly and rapidly than underground leaks on steel distribution pipes. Instead of small pin-hole leaks developing slowly over a number of years, as is typical of steel pipes, leaks on Aldyl A are far more likely to be of a serious nature much more quickly. The 1996 San Juan incident and the two 2011 California incidents are good examples of this abrupt failure characteristic.”⁴⁷¹

PG&E has 4,464 miles of plastic pipe manufactured between 1970 and 1983. The Staff Report assumes that this vintage pipe was installed in years 1970 to 1986.⁴⁷² All this pipe is potentially subject to rock impingement and other stresses that can cause slow crack growth and abrupt catastrophic failure. Given the 71 year Mean Time To Failure of this pipe when stressed, these failures could occur at any time over the next few decades unless the pipe is proactively replaced as PG&E proposes.

TURN makes the claim that Staff’s Report’s recommendations have been superseded by the SPD’s response to PG&E’s 2020 RAMP Report.⁴⁷³ The SPD response to the 2020 RAMP Report states that instead of PG&E’s proactive replacement program “[a] better approach to mitigate pre-1985 plastic pipe risk would be to determine the specific vintage and plastic composition of the pipe before committing to an expensive excavation and replacement of pipe that may present no particular risk.”⁴⁷⁴ However, as TURN’s witness John Sugar acknowledged, this recommendation in the RAMP report does not change the 2014 Staff Report’s assessment of the failure risks of Aldyl-A pipe, the 71 year MTTF of that pipe, or the recommendations of the report.⁴⁷⁵ Moreover, as recommended by the staff, PG&E is already using all information available to identify the highest risk pipe segments to prioritize the replacement of those segments. Specifically, PG&E’s DIMP risk model evaluates pipe segments

⁴⁷¹ PG&E-03, Staff Report, WP 4-136.

⁴⁷² PG&E-03, Staff Report p. 4-131. TURN-06-Atch1, PG&E’s response to Data Request TURN_083-05(d), dated 1/21/22, p. 167.

⁴⁷³ Tr. Vol. 13, 2472:19 to 2473:17, TURN/Sugar.

⁴⁷⁴ See PG&E-02, WP 1-43, lines 188 and 189.

⁴⁷⁵ Tr. Vol. 13, 2478:10-25, TURN/Sugar.

based on pipe characteristics, such as vintage and type, and leak data for replacement consideration and other mitigation activities.⁴⁷⁶ Neither TURN nor any other party has proposed a better way to determine the riskiest pipe.

PG&E's plastic pipe replacement program is designed to address the growing risk of abrupt and catastrophic failure of Aldyl-A pipe due to slow crack development that can take up to 71 years to develop. There is no way to mitigate this risk without proactively replacing the pipe before the expected peak failure period expected during the next decades when the pipe reaches its MTTF. Simply waiting for failures to occur is not an option. PG&E's approach is consistent with the data and analysis of the NTSB, PHMSA, the Staff Report, and the Office of the Safety Advocate (OSA)'s testimony in the 2020 GRC.

3.3.4.2 Aldyl-A Pipe Risks Continue to Grow Over Time

Both Cal Advocates and AARP argue that PG&E's proposal to increase the number of miles under the plastic pipe replacement program is not justified because the risks have not increased since the last rate case.⁴⁷⁷ However, the risk of failure of Aldyl-A pipe due to slow crack development is a growing, time-dependent risk that requires a proactive response. As explained above, and in a data response,⁴⁷⁸ PG&E has evaluated the near-and long-term risks with vintage plastic pipelines as described in PHMSA Advisory Bulletins⁴⁷⁹ and the Staff Report.⁴⁸⁰ There is a time-dependent failure for plastic pipe⁴⁸¹ and, as the Staff Report recommends, "operators should re-examine their risk assessment and mitigation strategies to

⁴⁷⁶ See PG&E-02, WP 1-43, line 189.

⁴⁷⁷ CALPA-02, p. 10, lines 20-29; AARP-01, p. 40, lines 1-3.

⁴⁷⁸ PG&E-16-E, PG&E's response to Data Request CalAdvocates_061-Q03, dated 9/24/21, p. AppA-226.

⁴⁷⁹ PG&E-03, WP 4-99 to WP-106.

⁴⁸⁰ PG&E-03, WP 4-107 to WP 4-142.

⁴⁸¹ PG&E-03, WP 4-125 to WP 4-126.

ensure they will be replacing the at-risk pipes at a sufficient rate to mitigate the risk associated with LDIW Aldyl A pipes dues [sic] to squeeze-offs and to pre-1983 non-LDIW pipes due to rock impingement.”⁴⁸² PG&E’s forecast is consistent with this recommendation.

AARP⁴⁸³ erroneously argues that no new regulations or pronouncements on Aldyl-A plastic have been issued since the 2020 GRC. On June 10, 2021, PHMSA issued an Advisory Bulletin (ADB-2021-01) that reminded operators that under the PIPES Act of 2020, Section 114, “O&M plans must address the replacement or remediation of pipelines that are known to leak based on the material (including cast iron, unprotected steel, wrought iron, and historic plastics with known issues), design, or past operating and maintenance history of the pipeline.”⁴⁸⁴ In addition, the Staff Report notes that some of their safety recommendations may exceed minimum compliance requirements.⁴⁸⁵

3.3.4.3 The Pace of PG&E’s Aldyl-A Pipe Replacement Program Is Justified

PG&E’s asset management goal is to achieve a steady-state replacement rate of 260 miles of main replacement per year by 2030 which will result in the removal of all pre-1985 pipe (approximately 26,000 miles) within 100 years.⁴⁸⁶ This includes PG&E’s proposal to remove 170.4 miles of pre-1985 Aldyl-A or similar plastic pipe in 2023 increasing to 186.5 miles in 2026 that will ensure that all Aldyl-A pipe is removed before it reaches its Mean Time to Failure of 71 years.

⁴⁸² PG&E-03, WP 4-140, No. 5 (emphasis added).

⁴⁸³ AARP-01, p. 40, lines 1-3.

⁴⁸⁴ 86 Fed. Reg. 31002 (June 10, 2021), <<https://www.govinfo.gov/content/pkg/FR-2021-06-10/pdf/2021-12155.pdf>> (as of Nov. 1, 2022), <<https://www.govinfo.gov/content/pkg/FR-2021-06-10/pdf/2021-12155.pdf>> (as of Nov. 1, 2022).

⁴⁸⁵ PG&E-03, WP 4-139.

⁴⁸⁶ PG&E-03, WP 4-41.

PG&E's proposed pace of replacement: addresses the Staff Report finding that pre-1985 plastic pipe will experience peak failure starting in 2050 (see discussion in Section 3.3.4.1 above); is consistent with the principle of steady state replacement of assets adopted by the Commission in the 2017 and 2020 GRC;⁴⁸⁷ exceeds the minimum of 139 miles per year replacement of pre-85 plastic pipe recommended by the OSA in the 2020 GRC;⁴⁸⁸ and follows the removal plan for all pre-1985 plastic pipe that PG&E was ordered to submit in its 2023 GRC showing.⁴⁸⁹

Adopting a lower rate of plastic pipe replacement as recommended by TURN, Cal Advocates, and AARP will not meet any of these principles and objectives, and most importantly will allow pre-1985 Aldyl A pipe to exceed the 71-year expected life for pipe manufactured between 1970 and 1983 (most of PG&E's installed pipe). Most extreme is TURN's recommendation to scale back the program to 59 miles per year. At this rate it will take over 100 years to remove all pre-1985 Aldyl pipe, guaranteeing that much of this pipe, if stressed or rock impinged, will eventually fail in service. As noted in the Staff Report, waiting for leaks to appear is a very high-risk strategy since these failures may manifest abruptly and rapidly, leading to serious consequences.

⁴⁸⁷ In both the 2017 and 2020 GRC the Commission adopted a requirement that "PG&E should strive for [reasonable rates of] steady state replacement . . . [that] includes proactive replacement of [an] asset prior to in-service failure." 2020 General Rate Case (GRC) Settlement Agreement, Section 5.1, adopted in Decision 20-12-005, p. 324, Section 16.1. Pursuant to this requirement, Chapter 21 of PG&E's June 30, 2020 RAMP report describes PG&E's risk-informed approach to pro-active asset replacement for each of its operating lines of business including Gas Operations. See Ex. PG&E-02, p. WP 1-869 to WP 1-880.

⁴⁸⁸ PG&E-54 (2020 GRC OSA testimony), p. 4-7, lines 6-8. The OSA based its recommendation on the findings of the 1998 NTSB report, the recommendations of the 2014 CPUC Staff Report, and OSA's finding that "[t]he potential danger posed by early vintage Aldyl-A and similar plastic pipes and the devastating impacts of their failures are well documented." PG&E-54, p. 4-6, lines 3-4.

⁴⁸⁹ 2020 Settlement Agreement adopted in the final GRC decision, D.20-12-005, p. 47. The removal plan is included in section C.2 of PG&E-03, p. 4-50, line 6 to p. 4-51, line 2.

3.3.4.4 PG&E Should Prioritize the Highest Risk Plastic Pipe in Accordance With Its DIMP Model

TURN's recommendation that PG&E focus on pre-1976 plastic pipe should be rejected.⁴⁹⁰ Adopting this recommendation would exclude from potential replacement under this program two thirds of PG&E's 6,509 miles installed plastic pipe, even where PG&E's risk evaluation DIMP risk model⁴⁹¹ indicates a post-1975 pipe segment as being high risk. Since the inception of the program, 187 of the 570 miles of high risk pipe that have been deactivated has consisted of pipe installed from 1976 to 1984.⁴⁹² Had a restriction such as TURN recommends been in effect during that time, almost one third of the total miles of pipe identified as high risk would not have been replaced.

TURN's claim that the primary risk resides with pre-1976 plastic pipe is not well founded. While the leak rate for the two plastic pipe cohorts is different, in the 5-year period between 2016 and 2020, pre-1976 plastic pipe experienced 717 leaks whereas 1976-1984 plastic pipe experienced 713 leaks.⁴⁹³ The likelihood of a loss of containment clearly exists for 1976-1984 plastic pipe. When a below-ground loss of containment event occurs, there is potential for gas migration to a nearby structure and ignition. For example, a gas leak ignition occurred in Woodland, California in 2004 as a result of a failure at a prior squeeze point on a plastic pipe installed in 1977.⁴⁹⁴ Indeed, TURN acknowledges the need to replace 1976-1984

⁴⁹⁰ TURN-06, p. 13, lines 9-15 and p. 20, lines 20-24.

⁴⁹¹ The DIMP risk model is required by Federal regulations and the CPUC's GO-112F. It is a multi-factor methodology to risk rank millions of individual pipe segments on PG&E's system to ensure that PG&E mitigates the highest risk segments. The methodology is more fully described in Section 3.3.

⁴⁹² TURN-06, pp. 175-178, PG&E's response to Data Request TURN_106-Q001, dated 2/15/22. The table shows total of 570.09 miles deactivated. 187 is the sum of deactivated main miles in installation years 1976 -1984.

⁴⁹³ PG&E-16-E, PG&E's response to Data Request TURN_048-Q01, dated 11/16/21 and TURN_048-Q01Atch01, pp. AppA-18 to AppA-62.

⁴⁹⁴ PG&E-16-E, PG&E's response to Data Request TURN_081-Q10, dated 1/19/22 and TURN_081-Q10Atch01, pp. AppA-221 to AppA-224.

plastic pipe when it noted that “[t]here are conditions, such as growing tree roots, earth movement, repair ‘squeeze offs’, etc., that cause stress and initiate cracking. These pipe failures must be resolved, no matter the calculated mean time to failure for that pipe formulation.”⁴⁹⁵

PG&E’s DIMP risk model provides prudent risk management and is capable of identifying segment-level main replacement to target locations where the risk resides, as the highest-risk segments are not necessarily limited to pre-1976 plastic pipe. The risk ranking is based on a methodology that considers leak history, pipe age, material type, ground temperature, diameter, operating pressure, and population proximity. PG&E continues to use prior leak history as a qualifier for pipe replacement recommendations.⁴⁹⁶

Finally, despite its assertion that PG&E should focus on pre-1976 pipe, TURN witness Sugar acknowledged on cross examination that PG&E should replace the highest risk pipe under this program regardless of when the pipe was installed.⁴⁹⁷ For these reasons PG&E should continue to replace the riskiest pipe segments as indicated by its risk models, regardless of the year the pipe was installed.

3.3.4.5 RSE Scores Are Not a Valid Basis to Drastically Reduce Program Funding

TURN’s and AARP’s reliance on RSE scores to support their respective proposals to significantly reduce program funding and slow the pace of the program is not warranted in light of the evolving nature of the RAMP process.⁴⁹⁸ PG&E addresses TURN’s flawed RSE approach in Sections 2.3 and 3.2.2.2 above.

As discussed above, the plastic pipe program is justified based on the well-documented risks of pre-1985 Aldyl-A pipe and principles of prudent, steady- state asset replacement before

⁴⁹⁵ TURN-06, p. 19, lines 12-15.

⁴⁹⁶ PG&E-16-E, PG&E’s response to Data Request TURN_106-Q009a, dated 2/15/22, p. AppA-225.

⁴⁹⁷ Tr. Vol. 13, 2443:22 to 2444:5, TURN/Sugar.

⁴⁹⁸ TURN-02, p. 80, lines 13-15; AARP-01, p. 41, lines 7-15.

assets reach their expected life. A proactive risk-informed replacement program to remove plastic pipe by the time it reaches its MTTF of 71 years is the best way to mitigate this risk. The need for such an approach has been recognized and recommended by the Commission's own expert safety staff.

Moreover, from an operational standpoint, the opinions of TURN's witnesses should be accorded lower weight than the judgment of PG&E's expert witness Mike Kerans, the PG&E Gas Operations asset family owner responsible for distribution pipeline integrity. TURN witnesses Lesser and Sugar lack the operational experience and expertise necessary to make judgments about pipeline asset integrity. Neither witness has worked as an employee of a natural gas transmission or distribution utility; neither is as an expert on federal pipeline integrity regulations; and neither has experience working on any committee of the American Gas Association (AGA).⁴⁹⁹ In contrast Mr. Kerans, who holds a Bachelor of Science degree in Mechanical Engineering, has over 15 years of experience in: gas transmission and gas distribution capacity planning; project engineering and management; distribution integrity management; investment planning processes; emergency response support operations; and regulatory compliance. He currently serves as a Chairman of the AGA Piping Material Committee.⁵⁰⁰

3.3.4.6 The Commission's Ongoing Long-Term Gas System Planning Proceeding Does Not Justify Reducing Program Spending

TURN argues that that drastically reducing spending on this program is justified because it could result in stranded investments if, as a result of the Commission's Long-Term Gas System

⁴⁹⁹ PG&E-16-E, p. 4-40, line 25 to p. 4-41, line 12 (Lesser qualifications); Tr. Vol. 13, 2435:23 to 2436:18, TURN/Sugar (Sugar qualifications).

⁵⁰⁰ PG&E-13, p. MK-1, lines 8-25.

Planning Proceeding (R.20-01-007) and decarbonization efforts, future gas through-put declines significantly.⁵⁰¹ This argument is flawed.

First, a Commission-adopted transition framework for the long-term future of natural gas utilities has not been finalized. PG&E has an obligation to continue providing safe, reliable and affordable service to its customers that requires continued investment in the gas system despite any potential decline in throughput.⁵⁰² PG&E has the obligation to design a program and a rate of pipe replacement targeted at the highest risk locations with demonstrated leak history and risk that provides the strongest indication of future integrity issues. PG&E's forecast for the plastic pipe program reflects these requirements, is consistent with PG&E's asset management plan, and incorporates California and federal best practices.⁵⁰³

Second, PG&E's gas distribution mains (not services) would be the last to be deactivated in an electrification scenario once all downstream services on that main were converted to an alternative energy source. PG&E foresees a sufficiently long future for the gas mains due to a continued need to serve customers downstream of areas that may have been converted to an alternative energy source. Gas mains will be necessary to maintain gas distribution system hydraulics for those customers who continue to use natural gas as an energy source. Replaced gas mains will be used by customers for cooking, heating, and commercial purposes, and will

⁵⁰¹ TURN-06, p. 8, line 26 to p. 9, line 4.

⁵⁰² PG&E-03, p. 1-7, lines 25-29.

⁵⁰³ PG&E-16-E, p. 4-40, lines 6-12.

continue to be used and useful into the future.⁵⁰⁴ This makes it important to continue addressing the safety risks of the gas distribution system.⁵⁰⁵

AARP recommends that PG&E “pursue full electrification first in areas served by pre-1985 Aldyl-A pipe ... to avoid replacement costs.”⁵⁰⁶ However, electrification is just beginning and is not currently feasible as an alternative to maintaining the existing gas distribution network. In the 2020 RAMP Report, Electrification was considered as an alternative to PG&E’s main replacement programs and proposed for the GPRP (MAT 14A) and the Plastic Pipe Replacement Program (MAT 14D) that the gas mains and services planned for replacement would be decommissioned and services converted to all-electric service.⁵⁰⁷ The cost estimate for deactivating pipelines and retrofitting homes found that electrification involves higher costs compared to pipe replacements.⁵⁰⁸ Thus, AARP’s proposal is likely to be more costly for customers.

AARP also claims that reducing the scope of plastic pipe replacement is justified because many cities and counties in PG&E’s service territory have adopted gas-free building commitments or electrification building codes.⁵⁰⁹ However, in discovery AARP conceded these

⁵⁰⁴ PG&E-16-E, p. 4-40, lines 13-24.

⁵⁰⁵ As CUE points out in its rebuttal testimony, it is inappropriate to “ignore safety until we figure out what we are doing about cost equity, electrification and future gas demand.” CUE-02, p. 14, lines 6-7. There are still significant unanswered questions about the future of gas, including how to satisfy the functions currently met by natural gas; the cumulative cost impact of switching fuels, and how those will be paid for; and the need to maintain the gas system safety and reliably for remaining gas usage. CUE-02, p. 15, lines 1-17.

⁵⁰⁶ AARP-01, p. 43, lines 8-11.

⁵⁰⁷ PG&E-16-E p. 4-49, line 27 to p. 4-15 line 11; see also PG&E’s 2020 RAMP Report, A.20-06-012 (June 30, 2020), PG&E-02, WP 1-357, lines 2 - 8.

⁵⁰⁸ PG&E-16-E, p. 4-50, lines 3-5.

⁵⁰⁹ AARP-01, p. 24, line 19 to p.25, line 1.

ordinances limit future growth in gas demand, but do not necessarily reduce current usage.⁵¹⁰ Since these ordinances will not reduce *current* demand, continued maintenance and replacement of the existing system is critical.

3.3.4.7 PG&E Expects To Complete the 417 miles in the 2020-2022 Aldyl-A Program

Cal Advocates claims that PG&E's forecast should be reduced because it failed to meet its plastic pipeline replacement goal in the current GRC period (2020-2022).⁵¹¹ However, Cal Advocates mischaracterizes PG&E's efforts to replace pre-1985 plastic pipe. PG&E completed 87 miles of replacement in 2020, which was a lower-than-expected number of units due to COVID-19 related project delays.⁵¹² PG&E completed 136.3 miles in 2021,⁵¹³ and testified that the balance of 193.3 miles by the end of 2022 to satisfy the 417 miles of plastic pipe replacement in the 2020 GRC Settlement Agreement is operationally achievable.⁵¹⁴

3.3.4.8 The 2023 Forecast Should Not be Based on 2021 Recorded Costs

Cal Advocates uses 2021 recorded costs (November YTD 2021 data plus an extrapolation for December 2021) for the Plastic Pipe Replacement Program instead of the base year 2020 recorded costs PG&E used in compliance with the RCP. PG&E does not agree with using 2021 recorded as the basis for the 2023 forecast. PG&E's forecast excludes 2021 recorded costs and is based on information that was known and available when PG&E's forecast was developed, consistent with RCP requirements. Cal Advocates' use of PG&E's 2021 forecast and recorded cost data is discussed in Section 1.5 of this opening brief.

⁵¹⁰ PG&E-16-E, AARP's Response to PG&E Data Request PGE_AARP002, Question 2-2, dated 7/5/22, p. AppA-232.

⁵¹¹ CALPA-02, p. 9, lines 23-25.

⁵¹² PG&E-03, p. 4-33, lines 9-10.

⁵¹³ PG&E-16-E, p. 4-43, lines 14-19.

⁵¹⁴ PG&E-16-E, p. 4-43, lines 22-23.

In addition, in 2021 PG&E completed only 136.3 miles of pipe replacement. However, PG&E is targeting a steadily increasing rate of replacement from 2023-2026 to ensure that all Aldyl-A pipe is removed before it reaches its Mean Time to Failure of 71 years as discussed in Sections 3.3.4.1 and 3.3.4.3 above. Accordingly, 2021 recorded costs are inadequate because they do not reflect PG&E's increased replacement rate.

3.3.4.9 The 2021 and 2022 Forecast Should Not be Based on 2021 Recorded Costs

Cal Advocates also recommends a forecast of \$396.4 million for 2021 and 2022 that is based on PG&E's capital expenditures in 2021.⁵¹⁵ This recommendation should be rejected by the Commission for the following reasons. First, use of 2021 recorded data is inconsistent with the RCP. The use of PG&E's 2021 forecast and recorded cost data is discussed in Section 1.5 of this opening brief. Second, with respect to the 2022 forecast, as explained above in Section 3.3.4.7, PG&E planned the completion of 193.3 miles by the end of 2022 to satisfy the 417 miles of plastic pipe replacement in the 2020 GRC Settlement Agreement. To base the 2022 forecast on 2021 recorded costs (representing completion of only 136.3 miles) would leave the 2022 work drastically under-funded.

3.3.4.10 The Commission Should Adopt PG&E's Unit Cost

PG&E determined its 2023 forecast of a \$578/foot unit cost for the Plastic Pipe Replacement Program based on a three-year average of recorded costs (2017-2019) with escalation.⁵¹⁶ The recorded financial data from 2020 was not used because it did not reflect normal operating conditions. AARP proposes a forecast unit cost for the Plastic Pipe Replacement Program based on the approved 2020 GRC funding of \$1.3 billion and unit target of 417 miles, which was calculated to obtain a unit cost of approximately \$2.95 million per mile

⁵¹⁵ CALPA-2, p. 11, lines 13-14 and p. 12, Table 2-9.

⁵¹⁶ PG&E-03, WP 4-41. The 2017 recorded cost was adjusted before escalation to account for spoils costs captured in MAT 14#.

or \$559/foot.⁵¹⁷ This approach is flawed because: (1) it does not use historic spend, such as the three-year average (2017-2019) of recorded spend and units used by PG&E; and (2) the AARP unit cost is not adjusted by escalating to 2023.⁵¹⁸

3.3.5 Reliability Service Replacement Program – Capital

The Reliability Service Replacement Program proactively replaces gas services, including copper services, to improve system safety and maintain compliance with pipeline regulations. Examples of reliability service replacements are shallow services; corroded risers; bent risers and unsafe meter locations.⁵¹⁹ PG&E is forecasting 800 replacements in 2023. The unit forecast for MAT 50B is based on a three-year average (2017-2019) of actual service replacements plus replacement of future discovery of copper services, and services discovered in the field that do not have installation records. From the three-year historical average of 427 service replacements, the unit forecast was rounded up to 500 services to include an estimate for future discovery of copper services. 300 additional units are forecasted for vintage services that were found in field with incomplete records. The unit cost forecast is based on a three-year average of recorded costs (2017-2019) with escalation.⁵²⁰ TURN and Cal Advocates propose the following reductions to the Reliability Services program:

⁵¹⁷ AARP-01, p. 40, lines 10-12.

⁵¹⁸ PG&E-16-E, p. 4-51, lines 15-20.

⁵¹⁹ The Reliability Service Replacement Program (MAT 50B) is more fully discussed in PG&E's prepared testimony. PG&E-03, p. 4-33, line 25 to p. 4-34, line 7.

⁵²⁰ PG&E-03, WP 4-44 to WP 4-45.

TABLE 3-8
RELIABILITY SERVICE REPLACEMENT PROGRAM (MAT 50B): PG&E'S CAPITAL
FORECAST AND PARTIES RECOMMENDED REDUCTIONS (\$000s)^(a)

Party	2020 Rec.	2021	2022	2023	2024	2025	2026
PG&E	\$10,940	\$3,040	\$10,210	\$22,036	\$22,586	\$23,106	\$23,637
Cal Advocates		\$(3,040)		\$(11,826)			
TURN				\$(8,318)	\$(8,451)	\$(8,671)	\$(8,897)
(a) PG&E-16-E, p. 4-59, Table 4-6, line 5 (2020-2022 recorded and forecast amounts); PG&E-3-ES, p. v (2023-2026 forecasts); PG&E-16-E, p. 4-4, Table 4-2, line 4 (Cal Advocates recommendation and TURN's 2024-2026 recommendation); PG&E-64, JCE p. 3-4 (TURN's 2023 recommendation).							

TURN proposes a cumulative reduction of \$34.3 million from PG&E's 2023 GRC cycle (2023-2026) forecast of \$91.3 million. While TURN accepts the 500 unit forecast based on the historical service replacement average plus the allocation for copper service discovery,⁵²¹ it rejects the 300 unit forecast for Vintage Services installed without documentation on the grounds that PG&E has not demonstrated any hazard from these services,⁵²² and lack of documentation reflects imprudence.⁵²³ To justify its reduction, Cal Advocates argues that: (1) funding the program in 2023 using the 2022 forecast amount of \$10.2 million is reasonable because it is comparable to the 2020 recorded amount of \$10.9 million; (2) this funding level would cover the replacement of 492 services; and (3) customers should not fund replacement of services that should have been maintained with the proper records.⁵²⁴ TURN's and Cal Advocates' arguments are addressed below.

3.3.5.1 Vintage Services Without Records Pose a Risk and Should Be Replaced

Both TURN and Cal Advocates object to PG&E's forecast to replace 300 vintage services that lack adequate records per year. Given the lack of material information for these

⁵²¹ TURN-06, p. 28, lines 10-12.

⁵²² TURN-06, p. 28, lines 1-7.

⁵²³ TURN-06, p. 27, lines 12-14.

⁵²⁴ CALPA-02, p.17, lines 1-17.

vintage services, PG&E conservatively assumes these services were installed prior to 1985 and therefore, pose a loss of containment risk due to the possibility that they were constructed of materials with time-dependent risk, such as copper.⁵²⁵ In addition, there is no evidence in the record that the lack of records for these vintage services was due in any way to non-compliance by PG&E with then-applicable record keeping requirements. It is prudent to replace these services given the risks.

3.3.5.2 Program Funding Should Be Based on PG&E's Undisputed Unit Cost Forecast

Cal Advocates recommends funding the program in 2023 using the 2022 forecast amount of \$10.2 million arguing that this amount is reasonable because it is comparable to the 2020 recorded amount of \$10.9 million. Cal Advocates claims this funding level would cover the replacement of 492 services.⁵²⁶ However, Cal Advocates' recommended level of funding is inadequate to fund even the units that Cal Advocates believes should be performed. Using PG&E's 2023 forecast unit cost of \$27,435, which is based on a three-year average of recorded costs (2017-2019) with escalation, which Cal Advocates' does not dispute, \$10.2 million in 2023 would fund the replacement of only 372 services and not 492 services as Cal Advocates states.⁵²⁷ The Commission should adopt PG&E's undisputed unit cost forecast of \$27,435 in 2023 and provide sufficient funding for PG&E to perform the number of replacement units deemed appropriate by the Commission.

3.4 Asset Family – Transmission Pipe

The Transmission Pipe asset family includes approximately 6,600 miles of natural gas pipelines and associated major components which transport gas from receipt points into PG&E's

⁵²⁵ PG&E-16-E, p. 4-56, lines 23-26.

⁵²⁶ CALPA-02, p. 16, lines 1-11.

⁵²⁷ PG&E-16-E, p.4-56, lines 14-20.

transmission pipeline system until the pipe arrives at a distribution center, storage facility, or large customer.

PG&E's TY 2023 expense forecast for the Transmission Pipe asset family is \$357.793 million.⁵²⁸ PG&E's TY 2023 forecast in the JCE is \$407.705 million⁵²⁹ The expense forecast includes work tracked in three MWCs.

PG&E's capital expenditures forecast is \$493.983 million in 2021, \$527.084 million in 2022, \$595.588 million in 2023, \$608.316 million in 2024, \$609.070 million in 2025, and \$627.115 million in 2026.⁵³⁰ The Transmission Pipe asset family capital expenditures forecast in the JCE is \$609.735 million in 2021, \$728.430 million in 2022, \$762.083 million in 2023, \$691.785 million in 2024, \$657.074 million in 2025, and \$657.815 million in 2026.⁵³¹

Many of the gas transmission expense and capital MATs are undisputed. For example, of the 29 expense MATs related to gas transmission, only 14 are disputed. Similarly, for the 20 gas transmission capital MATs, only 9 are disputed. The undisputed programs, associated MATs, and corresponding expense and capital forecasts are identified in Appendix A. In addition to expense and capital expenditure forecasts, PG&E also made recommendations regarding seven (7) existing memorandum and balancing accounts. Parties disputed recommendations for four (4) of the memorandum and balancing accounts. The three (3) undisputed memorandum and balancing account recommendations are also included in Appendix B.

The disputed programs, associated MATs, and balancing/memorandum account recommendations include:

⁵²⁸ See PG&E-3-ES, p. iii (PG&E's rebuttal expense forecast updated with corrected escalation factors).

⁵²⁹ PG&E-64, p. 3-1, Table 3A-1, lines 3-5.

⁵³⁰ PG&E-16-E, p. 5-91, Table 5-6, line 24 (2021 and 2022). PG&E-3-ES, p. v (PG&E's rebuttal capital forecast updated with corrected escalation factors) (2023-2026).

⁵³¹ PG&E-64, p. 3-6, Table 3B-1, lines 3-6 (2023); p. 3-6, Table 3B-2, lines 3-6 (2022); and p. 3-14, Table 3B-3, lines 3-6 (2021). The 2024-2026 forecast amounts are not included in the JCE but are provided here for reference.

**TABLE 3-9
SUMMARY OF ISSUES ADDRESSED IN SECTION 3.4**

Section in Brief	Disputed Program or Balancing/Memorandum Account	Impacted MATs
3.4.1	In-Line Inspection	75P, 98C, HPB, HPI, HPR
3.4.2	Direct Assessment	HPC, HPJ, HPK, HPN, HPO, HPP, HPU
3.4.3	Strength Testing	75Q, 75R, 75U, HPF, HPM, JT6
3.4.4	Vintage Pipe Replacements	75E
3.4.5	Shallow and Exposed Pipe (Including Water and Levee Crossings)	75K, 75M, 75T
3.4.6	Public Awareness	JT0
3.4.7	Transmission Integrity Management Program (TIMP) Balancing and Memorandum Accounts	N/A
3.4.8	In-Line Inspection (ILI) Program Balancing and Memorandum Accounts	N/A
3.4.9	Internal Corrosion Direct Assessment Memorandum Account	N/A

In the remainder of this Section 3.4, we address the disputed programs, as well as the disputed memorandum and balancing accounts.

3.4.1 In-Line Inspections (MWCs 75, 98, and HP)

The most vigorously contested issue related to PG&E’s gas transmission forecasts concerns the In-Line Inspection or “ILI” program. Under mandatory federal regulations⁵³², gas transmission operators must perform an initial (*i.e.*, baseline) assessment of transmission pipelines in High Consequence Areas (HCA), Moderate Consequence Areas (MCA), and Class 3 and 4 locations. Gas transmission operators must also perform re-assessments every seven years.⁵³³ Federal regulations provide for several methods to perform these baseline assessments and re-assessments, including ILI.

There are three phases in PG&E’s ILI Program. First, in order to perform an initial ILI assessment, a pipeline typically must be upgraded to make the line “piggable” (*i.e.*, able to receive traditional or non-traditional ILI tools which perform the actual assessment).⁵³⁴

⁵³² 49 Code of Federal Regulations (CFR), Part 192, Subpart O (Subpart O).

⁵³³ PG&E-16-E, p. 5-8, fn. 5 (citing federal regulations and explaining federal requirements).

⁵³⁴ PG&E-03, p. 5-22, lines 10-28; PG&E-16-E, p. 5-7, lines 24-31.

Upgrading a gas transmission pipeline for ILI assessments is a capital project and referred to as a Traditional ILI Upgrade. For brevity, in the remainder of this brief we will refer to this as an “ILI Upgrade.” Second, PG&E conducts the baseline assessment or re-assessment of the gas transmission pipeline. This phase is referred to as an ILI assessment and is an expense item. Third, after an ILI assessment occurs, PG&E may be required to schedule excavations (digs) and repair and/or replace certain portions of a pipeline based on the data gathered during the assessment. This third phase is referred to as Direct Examination and Repair or the “DE&R” phase and may involve both capital and expense.⁵³⁵ In this proceeding, PG&E has proposed capital and/or expense forecasts for ILI Upgrades, ILI assessments, and DE&R related to ILI assessments.

For all of the discussion in prepared testimony and at hearing concerning PG&E’s ILI program, it is notable that most of the key facts regarding the ILI Program are undisputed, including:

1. ILI is the most comprehensive and reliable pipeline integrity assessment tool currently available;⁵³⁶
2. Performing ILI Upgrades and assessments is an industry best practice for safety and reliability;⁵³⁷
3. ILI can assess and evaluate pipeline conditions and threats that cannot be evaluated by alternative assessment methods, such as Direct Assessment;⁵³⁸
4. In addition to assessing pipeline integrity, ILI Upgrades allow pipelines to be cleaned improving flow efficiencies and allow for other types of inspections.

⁵³⁵ PG&E-03, p. 5-22, line 10 to p. 5-25, line 29 (describing three phases of the ILI Program).

⁵³⁶ PG&E-03, p. 5-25, line 30 to p. 5-26, line 6 (describing comprehensive nature of ILI); PG&E-16-E, p. 5-7, lines 16-23 (describing comprehensive nature of ILI).

⁵³⁷ PG&E-16-E, p. 5-8, fn. 5; p. 5-10, lines 19-27 (industry best practice).

⁵³⁸ PG&E-03, p. 5-25, line 30 to p. 5-26, line 6 (comprehensive ILI assessment of threats); PG&E-16-E, p. 5-26, line 27 to p. 5-27, line 14 (comparing ILI assessments to other assessment methods and demonstrating that ILI is more comprehensive); p. 5-28, lines 6-9 (ILI assesses more threats than Direct Assessment).

Other assessment methods, such as Direct Assessment, do not provide these additional benefits;⁵³⁹

5. Upgrading gas pipelines to be capable of ILI assessments is consistent with California state law;⁵⁴⁰
6. The Commission has encouraged ILI upgrades and, in November 2021, the adopted safety performance metrics regarding the number of ILI Upgrades and assessments a utility performs annually;⁵⁴¹
7. PG&E's ILI Upgrade program is risk prioritized based on a comprehensive and detailed risk model referred to as the TIMP risk model that evaluates risk at a pipeline segment level and prioritizes work based on the highest threats;⁵⁴² and,
8. Only 43% of PG&E's transmission pipelines are piggable (i.e., can be assessed using ILI) as compared to 67% for Sempra and 70% nationally for non-California entities.⁵⁴³

These undisputed facts demonstrate the importance of the ILI Upgrade and assessment programs and fully support PG&E's forecast in this proceeding.

Despite the undisputed facts regarding the safety and reliability benefits of ILI, the Legislative and Commission policy supporting the use of ILI, and the significant difference between the amount of pipe that is piggable for PG&E as compared to other entities, TURN proposes slashing PG&E's ILI Upgrade program cost forecast by 73%.⁵⁴⁴ TURN instead advocates that PG&E rely on less comprehensive assessment methods, such as Direct Assessment, to satisfy federal regulations regarding transmission pipeline assessment, even

⁵³⁹ PG&E-16-E, p. 5-27, lines 15-25 (additional benefits of ILI).

⁵⁴⁰ Cal. Pub. Util. Code § 958(c)(3); PG&E-16-E, p. 5-12, lines 3-13 (describing legislative support for ILI Upgrades).

⁵⁴¹ D.20-05-037, p. 12 (encouraging ILI upgrades); D.21-11-009 (establishing an ILI upgrade metrics); PG&E-16-E, p. 5-12, line 14 to p. 5-13, line 13 (describing Commission directives regarding ILI upgrades).

⁵⁴² PG&E-16-E, p. 5-15, line 19 to p. 5-16, line 13 (describing PG&E risk prioritization of ILI Upgrades); p. 5-26, lines 4-22 (describing PG&E's threat assessment approach).

⁵⁴³ PG&E-03, p. 5-26, lines 22-29 and p. 5-27, Table 5-5 (identifying percentage of "piggable" miles for other utilities in and outside of California).

⁵⁴⁴ PG&E-16-E, p. 5-8, lines 20-21; TURN-04, p. 21, lines 4-5.

though these alternative methods are less cost-effective over the long-term.⁵⁴⁵ In short, TURN argues for a “bare minimum” approach to satisfy federal regulations, essentially ignoring the safety, reliability, and cost efficiency benefits of ILI.⁵⁴⁶

Specifically, TURN argues: (1) PG&E’s unit forecast for 12 ILI Upgrades per year should be slashed by 66% to 4 ILI Upgrades per year; (2) the unit cost forecast for ILI Upgrades should be reduced; (3) ILI Upgrades should not be included in officer performance metrics; (4) certain traditional ILI assessments should not be included in PG&E’s forecast; (5) certain Non-Traditional ILI assessments should not be included in PG&E’s forecast; and (6) the forecast for capital repairs related to ILI assessments should be lowered. In addition, TURN and Cal Advocates raise issues concerning PG&E’s DE&R expense forecast related to ILI assessments. Each of these arguments is addressed below. Issues related to the ILI Memorandum and Balancing Accounts are addressed in Section 3.4.8.

3.4.1.1 PG&E’s ILI Upgrade Forecast Should Not Be Reduced – Capital (MAT 98C)

Our opening testimony and workpapers describe the ILI Upgrade program and provide evidence demonstrating that the program and PG&E’s cost forecast are prudent and reasonable.⁵⁴⁷ TURN’s recommendations for ILI Upgrades include the number of units, unit costs, and the overall forecast. The recommendations for units and overall forecast are summarized below and the unit costs forecasts are addressed in Section 3.4.1.2:

⁵⁴⁵ See *e.g.*, TURN-04, p. 30, lines 3-10.

⁵⁴⁶ PG&E-16-E, p. 5-15, lines 4-18.

⁵⁴⁷ PG&E-03, p. 5-21, line 1 to p. 5-28, line 22; p. 5-33, line 19 to p. 5-35, line 4; PG&E-3-ES, WP 5-98 to WP 5-100.

TABLE 3-10
ILI UPGRADE (MAT 98C): PG&E’S CAPITAL FORECAST AND PARTIES RECOMMENDED REDUCTIONS (\$000s)^(a)

Party	2020 Rec.	2021	2022	2023	2024	2025	2026
PG&E	\$213,183	\$205,255	\$234,728	\$206,825	\$211,995	\$199,770	\$205,963
TURN				\$(151,914)			
(a) PG&E-16-E, p. 5-91, Table 5-6, line 22 (PG&E’s 2020-2022 recorded and forecast costs); PG&E-3-ES, p. v (PG&E’s 2023-2026 forecast); PG&E-64, p. JCE 3-16 (TURN’s recommendation)							

TURN recommends reducing the number of ILI Upgrades during the rate case period (2023-2026) from 12 to 4 based on TURN’s assertions that: (1) ILI Upgrades and assessments are not required by federal regulations, state law, or Commission precedent; (2) ILI Upgrades have a low RSE score; and (3) ILI Upgrades are unnecessary because the Commission is considering the termination of natural gas pipelines in the future.⁵⁴⁸ These arguments are based on flawed reasoning and are without merit.

As a preliminary matter, before addressing the substance of TURN’s three arguments, it is notable that this is not the first time that TURN has suggested drastically slowing the pace of ILI Upgrades. In the 2015 GT&S rate case, the Commission explained:

TURN has proposed that the pace of work for the ILI Upgrade program be reduced and that 20% of the forecast costs be disallowed. TURN argues that the pace of work should be 100 miles per year, rather than PG&E’s proposed pace of 177 miles per year. TURN notes that its proposed pace is double the pace of work under PSEP. However, as discussed by PG&E witness Barnes, if the pace of work were 100 miles per year, it would take PG&E 26 years to make its system piggable. We find such a length of time is not acceptable.⁵⁴⁹

The outcome here should be the same. As explained below, TURN’s proposal to reduce the ILI Upgrade pace from 12 units per year to 4 units per year is ill advised and fails to consider the benefits of ILI Upgrades, including critical safety and reliability benefits.

⁵⁴⁸ TURN-04, p. 9, line 17 to p. 12, line 25.

⁵⁴⁹ D.16-06-056, p. 42 (footnotes omitted).

3.4.1.1.1 Federal Regulations, State Law and Commission Precedent

TURN's first argument is that federal regulations allow for alternative assessment methods in addition to ILI and thus ILI Upgrades and assessments are not required.⁵⁵⁰ While TURN is correct that ILI is one of several assessment methods permitted under federal regulations, this does not change the undisputed facts that ILI is the most comprehensive and reliable assessment method, is an industry best practice, and performing ILI Upgrades is consistent with California legislative and CPUC directives including the safety performance metrics adopted by the CPUC last year.⁵⁵¹ In addition, as explained above, ILI Upgrades and subsequent ILI assessments provide additional benefits such as flow efficiencies and allowing for other types of inspections that alternative methods, such as Direct Assessment, do not provide. The availability of alternatives by itself does not indicate the alternatives are superior. While there is an initial capital expense performing an ILI Upgrade, once the upgrade is completed ILI assessments and re-assessments can be conducted on the upgraded pipeline section in a cost-effective and comprehensive manner.⁵⁵² Because re-assessments are required by federal regulations at least every 7 years in HCAs and every 10 years in MCAs, the initial investment in an ILI Upgrade will provide cost-effective long-term safety and reliability benefits, as compared to other alternatives such as Direct Assessment.

Although TURN advocates that PG&E use alternative assessment methods, such as Direct Assessment, in lieu of ILI Upgrades and assessments,⁵⁵³ TURN candidly admits that it “has not separately conducted an assessment of the strengths and weaknesses of the various

⁵⁵⁰ TURN-04, p. 10, lines 18-19.

⁵⁵¹ PG&E-16-E, p. 5-10, line 3 to p. 5-11, line 5 (comprehensive nature of ILI and industry best practice); p. 5-12, line 3 to p. 5-13, line 13 (California legislative and Commission support for and encouragement of ILI upgrades).

⁵⁵² PG&E-16-E, p. 5-28, line 27 to p. 5-29, line 17 (explaining how ILI is more cost-effective than Direct Assessment and providing an example).

⁵⁵³ TURN-04, p. 8, line 21 to p. 9, line 6.

assessment methods.”⁵⁵⁴ Nor does TURN dispute the superiority of ILI as compared to alternative assessment methods. As PG&E’s witness Bennie Barnes explained:

TURN’s supposition that Direct Assessment is a suitable substitute for ILI is not well founded. ILI is the most reliable pipeline integrity assessment tool currently available to natural gas pipeline operators to assess the internal and external condition of transmission line pipe and provides a means to assess the integrity of the pipeline for more threats than can be assessed through Direct Assessment. There are three types of Direct Assessment – ECDA, ICDA, and SCCDA – which are targeted to only assess the threats of external corrosion, internal corrosion, and stress corrosion cracking. ILI assesses for those threats and can also provide a means of assessing for manufacturing, land movement, and selective seam weld threats. In addition, each of the Direct Assessment methods only provides condition data for a short section of line while ILI provides condition data for significantly more pipeline and can then also often be used for corroborating GIS data, identifying pipeline bending strains caused by land movement and providing significant knowledge of long seam weld conditions. [TURN witness] Dr. Lesser’s analysis does not consider or evaluate the key differences between ILI and Direct Assessment methods, nor does he evaluate the additional safety and reliability benefits associated with ILI assessments.⁵⁵⁵

TURN acknowledges, as it must, that federal regulations require gas pipeline operators to choose the assessment method “best suited to address the threats identified” on particular pipeline segments.⁵⁵⁶ This is exactly what PG&E did in preparing its forecast for this proceeding. PG&E used its TIMP risk model, which includes hundreds of factors and a comprehensive set of pipeline segment attributes, to prioritize pipeline sections that should be upgraded for ILI.⁵⁵⁷ Based on that prioritization, ILI Upgrades will then be performed to allow for ILI assessments. Notably, federal regulations do not state that the decision to perform ILI Upgrades, and the subsequent ability to perform ILI assessments, should be based on RSE scores or benefit-cost ratio. Instead, in adopting its regulations, PHMSA recognized the importance of

⁵⁵⁴ PG&E-46, PG&E Data Request Set 23, Question 1(c).

⁵⁵⁵ PG&E-16-E, p. 5-26, line 26 to p. 5-27, line 14.

⁵⁵⁶ PG&E-46, PG&E Data Request Set 23, Question 1(a) citing 49 CFR § 192.937(c) (emphasis added).

⁵⁵⁷ PG&E-16-E, p. 5-15, line 19 to p. 5-16, line 15 (describing PG&E risk prioritization of ILI Upgrades); p. 5-26, lines 4-22 (describing PG&E’s threat assessment approach); see also TURN-118, PG&E’s response to Data Request TURN_222, Q001(b), dated 7/28/22 (describing TIMP operational risk model).

an operator choosing the assessment method best suited to address threats. In this case, because ILI is indisputably the most comprehensive and reliable pipeline integrity assessment tool, PG&E is prioritizing its highest risk pipeline segments for ILI Upgrades and subsequent assessments.

With regard to California state law and Commission directives, while ILI Upgrades are not required, they are strongly encouraged given the effectiveness of ILI. California Public Utilities Code Section 958(c)(3) provides that gas utilities should make transmission line segments “[w]here warranted, be capable of accommodating in-line inspection devices.” In addition to Legislative support, the Commission has also addressed the importance of ILI Upgrades and assessments in two recent decisions. First, in PG&E’s 2015 GT&S Rate Case,⁵⁵⁸ TURN and other parties challenged a number of issues including the necessity of the scope of work proposed by PG&E.⁵⁵⁹ The Commission rejected these parties’ arguments and, with regard to ILI, stated:

In addition, in 2011 we ordered all California gas transmission system operators to take additional actions beyond those required by federal pipeline safety laws. We required California operators to cease reliance on historical operating pressure to establish Maximum Allowable Operating Pressure (MAOP) on certain transmission pipelines, and instead to conduct a strength test or replace pipelines with no documentation of a prior strength test. We also ordered operators to modify pipelines to allow inline inspection where feasible, and to install automated valves. Joint Applicants acknowledge that these requirements are responsible for 40 percent of the approved revenue requirement increase. There is sufficient record evidence supporting our conclusion that the revenue requirement increase was needed to comply with new, heightened safety requirements.⁵⁶⁰

More recently, on November 9, 2021, the Commission issued a decision adopting Safety Performance Metrics, including metrics related to ILI Upgrades and assessments.⁵⁶¹

⁵⁵⁸ A.13-12-012, Pacific Gas and Electric Company’s 2015 Gas Transmission and Storage Rate Case Application (Dec. 19, 2013).

⁵⁵⁹ D.20-05-037, p. 11.

⁵⁶⁰ D.20-05-037, p. 12 (citations omitted and emphasis added).

⁵⁶¹ D.21-11-009.

Specifically, the Commission adopted metrics for the total miles California gas operators inspected annually by ILI, total miles and percentage of system that is piggable, and the number of “miles of gas transmission lines upgraded annually to permit inline inspections.”⁵⁶² If the Commission did not think ILI Upgrades were important, it would not be setting a safety metric to measure how many miles of upgrades a utility performed each year.

TURN hangs its hat on the language “where warranted” in Public Utilities Code Section 958(c)(3) to argue that, in cases where TURN does not believe the RSE scores or benefit-cost ratio are sufficient to justify an ILI Upgrade, an ILI Upgrade is not warranted.⁵⁶³ However, if the Commission or the California Legislature had intended cost-effectiveness to be the sole criteria for ILI Upgrades, they would have said so explicitly rather than more generally requiring ILI assessment to be performed where warranted. Moreover, as explained above, the Commission has strongly encouraged ILI Upgrades.

3.4.1.1.2 RSE Scores and Benefit-Cost Ratios

TURN’s second argument regarding ILI Upgrades is based on RSE scores and benefit-cost ratios. TURN argues that because ILI Upgrades have low RSE scores and benefit-cost ratios, the program should be dramatically reduced.⁵⁶⁴ This argument is based entirely on TURN’s flawed RSE and benefit-cost analysis, which is addressed generally in Section 2.3 of this opening brief.

With regard to ILI Upgrades specifically, TURN’s analysis is also flawed because it focuses on the RSE values for ILI Upgrades alone and does not adequately consider ILI assessments, which have a separate RSE score. The RSE scores for ILI Upgrades and ILI assessments must be considered in tandem because an ILI assessment typically cannot occur

⁵⁶² D.21-11-009, Appendix B, p. 3, Items 6 and 7, p. 5, Item 13.

⁵⁶³ TURN-04, p. 11, lines 2-4.

⁵⁶⁴ TURN-04, p. 11, lines 5-21.

unless and until a pipeline has first had an ILI Upgrade.⁵⁶⁵ In other words, the safety and reliability benefits of ILI assessments can only be achieved when an ILI Upgrade has first been performed. This is exactly why the Commission established as safety performance metrics the number of miles per year that have been upgraded annually to permit ILI assessments – without ILI Upgrades, ILI assessments cannot be performed.⁵⁶⁶ Moreover, TURN does not dispute the fact that PG&E’s ILI Upgrade program is risk based so that work performed during the rate case period (2023-2026) will prioritize the highest risk pipeline segments remaining in PG&E’s system that have not yet been upgraded.⁵⁶⁷ Thus, the ILI Upgrades proposed for 2023-2026 will have the highest risk reduction value for customers.

In response to discovery and at the hearing, PG&E acknowledged that there were inadvertent errors in the RSE calculations for ILI Upgrades and ILI assessments which resulted in overlap between the scores for the two programs.⁵⁶⁸ PG&E witness Vincent Tanguay also indicated that there were additional benefits associated with ILI Upgrades that are not currently captured in the RSE calculations.⁵⁶⁹ These additional ILI Upgrade benefits, which were not included in the RSE calculations, were described in discovery responses.⁵⁷⁰ Because of the errors and incompleteness of the RSE calculations for ILI Upgrades and ILI assessments, we intend to substantively revise the calculation methodology in the future, likely in the next RAMP

⁵⁶⁵ PG&E-16-E, p. 5-14, lines 5-18.

⁵⁶⁶ D.21-11-009, Appendix B, p. 3, Items 6 and 7, p. 5, Item 13.

⁵⁶⁷ PG&E-16-E, p. 5-15, line 19 to p. 5-16, line 15; Tr. Vol. 5, 895:6-9 PG&E/Barnes, 900:7 to 901:4 PG&E/Barnes.

⁵⁶⁸ Tr. Vol. 5, 788:14 to 791:24, PG&E/Tanguay; TURN-131, PG&E’s response to Data Request TURN_261-Q001Rev01(a), dated 8/24/22.

⁵⁶⁹ Tr. Vol. 5, 795:3-9; 801:11-802:2, PG&E/Tanguay.

⁵⁷⁰ TURN-121, PG&E’s response to Data Request TURN_226-Q002(a), dated 8/4/22.

proceeding.⁵⁷¹ However, as PG&E witness Bennie Barnes explained, focusing solely on RSE scores to determine whether PG&E should continue to perform ILI Upgrades is unreasonable because it does not adequately consider the “real-world risks” that are addressed by the ILI Program, including ILI Upgrades.⁵⁷² Thus, the inadvertent errors identified in the ILI Upgrade and ILI assessment RSE calculations do not obviate the need for or important safety and reliability benefits related to ILI Upgrades.

3.4.1.1.3 Future Natural Gas Pipeline Usage

TURN’s third argument to support its dramatic ILI Upgrade reductions is that ILI Upgrades are unnecessary because the Commission is addressing the potential “termination of the use of natural gas pipelines in the foreseeable future.”⁵⁷³ However, the Commission proceeding cited by TURN to support this assertion is still in its early stages and the Commission has not yet developed or implemented a long-term natural gas strategy. Moreover importantly, PG&E cannot simply abandon its responsibility to provide safe and reliable service and to comply with federal regulations and California legislative and Commission directives simply because an ongoing proceeding is considering the long-term future of the natural gas industry in California.⁵⁷⁴ TURN appears willing to ignore current safety, reliability, and compliance needs because the state is planning to decrease its need for and use of natural gas transmission pipelines. Such proposals to defer critical safety projects such as ILI Upgrades until some undefined point based on TURN’s hope that conditions or needs change in the future, is in appropriate and should be rejected.

⁵⁷¹ Tr. Vol. 5, 799:28 – 801:1, PG&E/Tanguay; TURN-131, PG&E’s response to TURN_262-Q003(a), dated 8/19/22.

⁵⁷² Tr. Vol. 5, 898:14-22, PG&E/Barnes.

⁵⁷³ TURN-04, p. 10, lines 3-17.

⁵⁷⁴ PG&E-16-E, p. 5-18, lines 2-25.

3.4.1.1.4 TURN's ILI Upgrade Proposal Should Be Rejected

Finally, it is important to put TURN's arguments regarding ILI Upgrades into context. TURN does not and cannot dispute that federal regulations require a baseline assessment and periodic re-assessments of gas transmission pipelines located in certain areas (e.g., HCAs, MCAs). TURN instead argues that to meet these federal requirements, PG&E should use other assessment methods such as Direct Assessment.⁵⁷⁵ TURN's only support for this argument is Dr. Lesser's flawed RSE and benefit-cost analysis. However, Dr. Lesser's theoretical arguments ignore practical realities that highlight the cost-effectiveness and comprehensive nature of ILI.⁵⁷⁶ PG&E provided an example of this in rebuttal. TURN recommends that PG&E perform Direct Assessment on a pipeline that has external corrosion, stress corrosion cracking, third-party damage, and land movement threats (i.e., pipe RUNID K024-1).⁵⁷⁷ Direct Assessment can only address the first two threats and thus is less comprehensive and exposes our customers and communities we serve to greater risk. Moreover, performing these less comprehensive Direct Assessments costs approximately 80% more than an ILI assessment.⁵⁷⁸ While there are initial capital costs for an ILI Upgrade to be performed, once it is performed, ILI is more cost-effective than Direct Assessment. And because re-assessments are required by federal regulations to occur every 7 years in HCAs and every 10 years in MCAs, over time the initial capital costs for an ILI Upgrade will be recovered through lower cost ILI assessments.⁵⁷⁹ TURN's proposal that PG&E pursue a less comprehensive and more costly assessment process over the long term is not reasonable or prudent.

⁵⁷⁵ TURN-04, p. 8, line 21 to p. 9, line 6.

⁵⁷⁶ TURN-04, p. 11, lines 5-21.

⁵⁷⁷ TURN-04, p. 24, Table 4 and p. 28, line 21 to p. 29, line 19 (arguing assessment can be performed on pipeline segments rather than ILI).

⁵⁷⁸ PG&E-16-E, p. 5-28, line 27 to p. 5-29, line 17.

⁵⁷⁹ PG&E-16-E, p. 5-29, lines 12-17.

In short, TURN has offered no persuasive reasons to reduce PG&E’s forecast of 12 ILI Upgrades per year during the rate case period. Moreover, TURN offers no support for its proposal to reduce this number to 4 ILI Upgrades per year.⁵⁸⁰ Given the undisputed safety and reliability benefits of ILI Upgrades, as well as the California Legislative and Commission directives for utilities to perform these upgrades, TURN’s unsupported proposal should be rejected and PG&E’s ILI Upgrade forecast of 12 per year should be adopted.

3.4.1.2 PG&E’s Unit Cost Forecast for ILI Upgrades Is Reasonable - Capital (MAT 98C)

In addition to disputing the number of ILI Upgrades that should be performed each year during the rate case period, TURN also disputes PG&E’s forecasted unit cost for ILI Upgrades. The parties’ recommendations for unit costs are:

**TABLE 3-11
SUMMARY OF PROPOSED UNIT COSTS FOR ILI UPGRADES**

Party/Issue	Proposal	Source
PG&E/Unit Cost	\$16.2 million/project (\$2020)	PG&E-03, WP 5-98
TURN/Unit Cost	\$12.6 million/project (\$2020)	TURN-04, p. 20, line 18

PG&E provided a detailed workpaper that described how the ILI Upgrade unit cost forecast was developed.⁵⁸¹ PG&E also explained that this forecast differed from the 2019 GT&S rate case forecast because, in that case, PG&E had not included the full cost of each project such as costs for engineering, permitting, and costs associated with closing out a project (i.e., carryover costs).⁵⁸² PG&E referred to these costs as programmatic costs. Despite the detailed information provided by PG&E regarding actual ILI Upgrade costs and programmatic costs, TURN proposes to reduce the ILI Upgrade unit cost forecast by more than 20%.⁵⁸³

580 TURN-04, p. 12, lines 11-12 (justifying in a single sentence TURN’s proposal for 4 ILI Upgrades per year).

581 PG&E-3-ES, WP-5-98 to WP 5-99.

582 PG&E-03, p. 5-34, fn. 43.

583 PG&E-16-E, p. 5-22, lines 21-25; TURN-04, p. 20, lines 18-25.

TURN's sole dispute concerning the ILI Upgrade unit cost forecast concerns "carry over costs", which are a subset of the programmatic costs included in PG&E's forecast.⁵⁸⁴ Carryover costs are costs that are incurred after a project becomes operational to close out the project, such as street paving where a project required a street to be excavated or site remediation.⁵⁸⁵ These costs can often occur a year or more after a project becomes operational but must be included to accurately determine a project's total cost. TURN does not dispute that carryover costs should be considered.⁵⁸⁶ Instead, TURN disputes how PG&E calculated the carryover costs.

To develop its ILI Upgrade Unit cost forecast, PG&E used actual ILI Upgrade costs from 2016-2019, the most current and complete data available when PG&E filed its Application. Because carryover cost information for projects completed in some of these years was not yet available (i.e., carryover cost information for a 2019 project was not fully available when PG&E submitted its Application in June 2021), PG&E used actual carry-over costs from pre-2016 projects as a proxy for the carry-over costs associated with 2016-2019 projects.⁵⁸⁷ TURN proposes a different approach. TURN developed an average carryover cost for projects completed between 2013-2017 and then applied this calculated average to the 2016-2019 projects.⁵⁸⁸

There are several problems with TURN's unit cost approach. First, TURN is not using actual project costs but instead is applying calculated percentages, which creates the potential for substantial under- or over-estimation of carry over costs. This problem is evident from TURN's own testimony. For example, TURN calculated that carry over costs for the three years after a project became operational were, on average, 6.1% of the total project cost. However, the actual

⁵⁸⁴ TURN-04, p. 16, line 1 to p. 19, line 18.

⁵⁸⁵ PG&E-16-E, p. 5-20, lines 19-22.

⁵⁸⁶ PG&E-16-E, p. 5-20, lines 23-24.

⁵⁸⁷ PG&E-16-E, p. 5-21, lines 1-22.

⁵⁸⁸ PG&E-16-E, p. 5-21, line 23 to p. 5-22, line 2; TURN-04, p. 17, line 23 to p. 19, line 18.

carry over costs for projects in 2017 was 8.2%.⁵⁸⁹ TURN's methodology would effectively under-estimate the actual 2017 carry over costs by approximately 26%. In other years, TURN's approach would significantly over-estimate carry over costs. While TURN may argue that it is using an average, so that under- and over-estimates balance out, it is not clear that the 2023-2026 ILI Upgrades at issue in this proceeding will fit TURN's average and thus customers may be significantly over- or under-paying for ILI Upgrade carry over costs. Rather than trying to calculate an average, which may or may not be accurate, PG&E's unit cost methodology uses actual carryover costs as a reasonable proxy.

Second, by narrowly focusing on carryover costs, TURN essentially ignores other programmatic costs that are associated with an ILI Upgrade, such as engineering which occurs before construction commences or permitting and land rights costs that are not always carried as a project order cost. These costs should be included in the ILI Upgrade unit cost forecast but TURN fails to do so in its proposed forecast.⁵⁹⁰ TURN fails to offer any explanation as to why these costs should not be included. Because TURN's ILI Upgrade unit cost forecast is flawed, it should be rejected and PG&E's unit cost forecast should be used.

3.4.1.3 Performance Metrics

In addition to concerns about the number and unit costs of ILI Upgrades, TURN also recommends that ILI Upgrade metrics be removed from PG&E employee performance goals so that employees are not incented to perform ILI Upgrades.⁵⁹¹ TURN's concerns on this issue are misplaced. First, TURN ignores the bias controls included in performance metrics that should address any concerns about improper incentives. Second, and more importantly, TURN ignores the fact that the Commission has adopted ILI Upgrades as a safety performance metric. It is

⁵⁸⁹ TURN-04, p. 19, Table 3.

⁵⁹⁰ PG&E-16-E, p. 5-22, lines 9-20.

⁵⁹¹ TURN-04, p. 13, lines 1-19.

difficult to understand why ILI Upgrades, which the Commission clearly wants to incent, should not be included in employee performance goals.⁵⁹²

3.4.1.4 PG&E's Traditional ILI Assessment Forecast Is Reasonable - Expense (MAT HPB)

Traditional ILI assessments occur when an inspection tool is moved through a pipeline driven by pressure differentials generated by gas flows.⁵⁹³ Our opening testimony and workpapers describe the Traditional ILI Assessment program and provide evidence demonstrating that the program and PG&E's cost forecast for the rate case period are prudent and reasonable.⁵⁹⁴ TURN was the only party to address traditional ILI assessments and proposed a reduction in the number of ILI assessments and a corresponding a 50% reduction to PG&E's expense forecast:

TABLE 3-12
ILI ASSESSMENT (MAT HPB): PG&E'S EXPENSE FORECAST AND PARTIES
RECOMMENDED REDUCTIONS (\$000s)^(a)

Party	2020 Rec.	2021	2022	2023
PG&E	\$69,566	\$88,004	\$58,188	\$57,230
TURN				\$(28,721)
(a) PG&E-16-E, p. 5-89, Table 5-5, line 4 (PG&E's 2020-2022 recorded and forecast costs); PG&E-3-ES, p. iii (PG&E's 2023 forecast); PG&E-64, p. JCE 3-21 (TURN's recommendation)				

There are three reasons for TURN's proposed reductions: (1) PG&E's unit cost forecast; (2) eliminating first-time ILI assessments associated with ILI Upgrades during the rate case period; and (3) postponing ILI assessments where the compliance date is in 2027, one year outside of the rate case period.⁵⁹⁵ Each of these issues is addressed below.

⁵⁹² PG&E-16-E, p. 5-23, lines 3-17.

⁵⁹³ PG&E-16-E, p. 5-23, lines 19-23.

⁵⁹⁴ PG&E-03, p. 5-28, line 25 to p. 5-30, line 17; WP 5-8 to WP 5-10, WP 5-55 to WP 5-57.

⁵⁹⁵ PG&E-16-E, p. 5-24, lines 1-15; TURN-04, p. 22, line 18 to p. 23, line 16 (regression analysis), p. 24, line 1 to p. 30, line 23 (eliminating 28 first time ILI assessments; p. 31, line 1 to p. 32, line 2 (postponing ILI assessments).

First, TURN proposes to reduce the unit cost of traditional ILI assessments based on carryover costs (which is addressed above in Section 3.4.1.2) and TURN's regression analysis of prior traditional ILI assessment costs. However, TURN's regression analysis was incomplete, using only 21 of the 25 historical projects identified by PG&E in discovery.⁵⁹⁶ TURN never explains its selective use of project data and this initial flaw taints its regression analysis. TURN's proposed unit cost analysis should be rejected and PG&E's regression analysis, which uses a complete data set from 2017-2019, should be adopted.

Second, TURN proposes to remove 28 traditional ILI assessments that are associated with the ILI Upgrades proposed for the rate case period (2023-2026). After an ILI Upgrade is performed, a baseline assessment occurs typically the year after the upgrade is completed. Because TURN is proposing to drastically reduce the number of ILI Upgrades performed during the rate case period, it is also proposing that the number of ILI assessments associated with those upgrades can be reduced by 28 traditional ILI assessments.⁵⁹⁷ For 12 of these 28 assessments, TURN argues that the assessment will not occur in HCA areas and thus neither an ILI Upgrade nor an associated assessment is needed.⁵⁹⁸ However, TURN ignores the comprehensive analysis performed by PG&E to identify the highest risk pipeline segments, including the 12 segments in non-HCA areas, and the fact that even though not in HCA areas, each of these pipelines could impact people living within the pipeline's impact radius.⁵⁹⁹ While TURN argues that PG&E could use alternative assessment methods for these 12 pipelines, this argument ignores the evidence discussed in more detail in Section 3.4.1.1 above that ILI is the most effective assessment method for safety and reliability. TURN's argument also ignores that, over

⁵⁹⁶ PG&E-16-E, p. 5-24, line 20 to p. 5-25, line 6.

⁵⁹⁷ PG&E-16-E, p. 5-25, lines 21-26.

⁵⁹⁸ TURN-04, p. 25, line 20 to p. 28, line 20.

⁵⁹⁹ PG&E-16-E, p. 5-26, lines 4-22; p. 5-28, lines 10-16.

time, ILI can be more cost-effective than other assessment approaches such as Direct Assessment.⁶⁰⁰

Seven (7) more of the traditional ILI assessments disputed by TURN are located in HCA areas but have less than one mile of HCA mileage. TURN’s proposal to use Direct Assessment for these pipeline sections rather than ILI suffers from the flaws described above in Section 3.4.1.⁶⁰¹ Finally, the remaining nine (9) pipelines of the 28 identified by TURN have more than a mile of HCA mileage.⁶⁰² TURN’s proposal to use Direct Assessment for these 9 pipelines has the same flaws as described in Section 3.4.1. In addition, in performing its cost analysis, TURN assumed that only an external corrosion direct assessment would be needed, which is not the case, and thus TURN artificially lowered the costs of Direct Assessment for these pipeline segments.⁶⁰³

Third, TURN proposes delaying 23 ILI assessments that have re-assessments deadlines in 2027, outside of the rate case period (2023-2026).⁶⁰⁴ PG&E generally performs ILI reassessments one year before the compliance deadline. This is prudent because it allows PG&E to take into consideration potential permitting delays, impacts of outages for an ILI assessment on system reliability, vendor delays, and other factors and ensures that PG&E will not miss the deadlines mandated by federal law.⁶⁰⁵ TURN’s “wait until the last minute” approach creates potential compliance problems and is neither reasonable nor prudent.

⁶⁰⁰ PG&E-16-E, p. 5-27, line 26 to p. 5-28, line 9.

⁶⁰¹ PG&E-16-E, p. 5-28, line 17 to p. 5-29, line 17; TURN-04, p. 28, line 21 to p. 29, line 19.

⁶⁰² TURN-04, p. 30, lines 1-23.

⁶⁰³ PG&E-16-E, p. 5-29, line 18 to p. 5-30, line 5.

⁶⁰⁴ TURN-04, p. 31, line 1 to p. 32, line 2.

⁶⁰⁵ PG&E-16-E, p. 5-30, line 21 to p. 5-31, line 14.

3.4.1.5 PG&E's Non-Traditional ILI Assessment Forecast Is Reasonable – Expense (MAT HPR)

Non-traditional ILI assessments occur when an ILI tool moves through the interior of a pipeline by means other than gas pressure differentials, such as robotic and tractor tools or winching with a cable.⁶⁰⁶ Our opening testimony and workpapers describe the Non-Traditional ILI Assessment program and provide evidence demonstrating that the program and PG&E's cost forecast for the rate case period are prudent and reasonable.⁶⁰⁷ TURN was the only party that proposed a reduction:

TABLE 3-13
NON-TRADITIONAL ILI ASSESSMENT (MAT HPR): PG&E'S EXPENSE FORECAST AND PARTIES RECOMMENDED REDUCTIONS (\$000s)^(a)

Party	2020 Rec.	2021	2022	2023
PG&E	\$16,827	\$35,558	\$23,000	\$13,442
TURN				\$(1,810)

(a) PG&E-16-E, p. 5-89, Table 5-5, line 16 (PG&E's 2020-2022 recorded and forecast costs); PG&E-3-ES, p. iii (PG&E's 2023 forecast); PG&E-64, p. JCE 3-21 (TURN's recommendation)

TURN's proposed reduction is based on a regression analysis that was incomplete because it mistakenly removed a project as an outlier and uses TURN's approach to carryover costs described above in Section 3.4.1.2.⁶⁰⁸ Given these problems with TURN's approach, its proposed reduction should be rejected.

3.4.1.6 PG&E's ILI Capital Repairs Forecast Is Reasonable – Capital (MAT 75P)

After an ILI assessment occurs, if specific anomalies in the pipe are identified, PG&E will conduct further evaluation and repairs as a mitigation, as required by federal regulations.⁶⁰⁹ This is referred to as direct examination and repair or DE&R. DE&R includes both expense and

⁶⁰⁶ PG&E-16-E, p. 5-31, line 19-24.

⁶⁰⁷ PG&E-03, p. 5-30, line 18 to p. 5-31, line 23; PG&E-3-ES, WP 5-14; PG&E-03, WP 5-55 to WP 5-57.

⁶⁰⁸ PG&E-16-E, p. 5-32, lines 5-17; TURN-04, p. 32, lines 10-18.

⁶⁰⁹ PG&E-16-E, p. 5-32, lines 19-25; p. 5-35, lines 24-29.

capital forecasts. Our opening testimony and workpapers describe the ILI DE&R capital program and provide evidence demonstrating that the program and PG&E’s cost forecast for the rate case period are prudent and reasonable.⁶¹⁰ TURN was the only party to dispute PG&E’s DE&R capital forecast:

TABLE 3-14
ILI CAPITAL REPAIRS (MAT 75P): PG&E’S CAPITAL FORECAST AND PARTIES
RECOMMENDED REDUCTIONS (\$000s)^(a)

Party	2020 Rec.	2021	2022	2023	2024	2025	2026
PG&E	\$15,357	\$14,310	\$19,419	\$15,004	\$15,379	\$15,810	\$16,300
TURN				\$(2,407)			
(a) PG&E-16-E, p. 5-91, Table 5-6, line 13 (PG&E’s 2020-2022 recorded and forecast costs); PG&E-3-ES, p. v (PG&E’s 2023-2026 forecast); PG&E-64, p. JCE 3-13 (TURN’s recommendation)							

To justify its proposed reduction, TURN used 2016-2020 repair cost data, rather than the 2017-2019 data used by PG&E.⁶¹¹ However, as PG&E explained in rebuttal testimony, the recorded capital costs for 2016 were abnormally low compared to later years because in the later years PG&E has been using more technologically advanced inspection tools.⁶¹² Because TURN’s proposed reduction is based on outdated data using an earlier generation of technology (*i.e.*, 2016), its proposal should be rejected.

3.4.1.7 PG&E’s Forecast for DE&R Expense Associated With ILI Assessments Is Reasonable – Expense (MAT HPI)

The final disputed forecast related to ILI concerns PG&E’s expense forecast for DE&R. This forecast is disputed by both TURN and Cal Advocates. Our opening testimony and workpapers describe the ILI Assessment program and provide evidence demonstrating that the

⁶¹⁰ PG&E-03, p. 5-35, line 5 to p. 5-36, line 27; PG&E-3-ES, WP 5-100.

⁶¹¹ TURN-04, p. 34, lines 3-11.

⁶¹² PG&E-16-E, p. 5-36, lines 5-13.

program and PG&E’s cost forecast for the rate case period are prudent and reasonable.⁶¹³ The parties’ proposed forecasts for this program are:

TABLE 3-15
DE&R EXPENSES ASSOCIATED WITH ILI ASSESSMENT (MAT HPI): PG&E’S EXPENSE FORECAST AND PARTIES RECOMMENDED REDUCTIONS (\$000s)^(a)

Party	2020 Rec.	2021	2022	2023
PG&E	\$32,048	\$64,833	\$51,536	\$71,464
Cal Advocates				\$(39,416)
TURN				\$(26,804)
(a) PG&E-16-E, p. 5-89, Table 5-5, line 9 (PG&E’s 2020-2022 recorded and forecast costs); PG&E-3-ES, p. iii (PG&E’s 2023 forecast); CA-02, p. 20, Table 2-17 (calculated as \$71,464-\$32,048=\$42,286); PG&E-64, p. JCE 3-21 (TURN’s recommendation)				

Cal Advocates argues that the number of DE&R digs in the 2023 forecast should be the same as the number of digs that occurred in 2020.⁶¹⁴ However, as PG&E explained in rebuttal testimony, because there will be more miles of ILI assessments performed, it is completely reasonable to expect that more anomalies will be detected and thus more digs performed. The greater the number of ILI assessment miles, the greater the expectation that there will be more anomalies and more digs.⁶¹⁵ Notably, Cal Advocates does not dispute the unit cost forecasted by PG&E for DE&R expense.⁶¹⁶

TURN disputes the number of DE&R units (*i.e.*, digs) as well as the unit costs. With regard to the number of DE&R units, TURN’s argument is based on its proposal to reduce the number of ILI assessments resulting in a corresponding reduction in DE&R units.⁶¹⁷ TURN’s proposal to reduce traditional ILI assessments is addressed above in Section 3.4.1.4. TURN’s

⁶¹³ PG&E-03, p. 5-32, line 1 to p. 5-33, line 18; PG&E-3-E, WP 5-15; PG&E-03, WP 5-55 to WP 5-57.

⁶¹⁴ CALPA-02, p. 19, lines 7-19 and p. 20, Table 2-17.

⁶¹⁵ PG&E-16-E, p. 5-33, lines 12-18.

⁶¹⁶ PG&E-16-E, p. 5-33, line 19 to p. 5-34, line 7.

⁶¹⁷ PG&E-16-E, p. 5-35, lines 14-22; TURN-04, p. 33, lines 16-17.

argument on unit costs is based on its use of 2016-2020 costs instead of the 2017-2019 actual costs used by PG&E for its forecast.⁶¹⁸ However, as PG&E explained in rebuttal testimony: (1) TURN miscalculated the number of previous year ILI miles used for its calculation; (2) TURN's regression analysis is less accurate than the analysis used by PG&E.⁶¹⁹ Given these shortcomings, TURN's proposed unit cost should not be adopted.

3.4.2 Direct Assessment (MWC HP)

In addition to ILI, Direct Assessment is another method for conducting pipeline integrity assessments. There are four types of Direct Assessment – external corrosion direct assessment (ECDA), internal corrosion direct assessment (ICDA), stress corrosion cracking direct assessment (SCCDA), and direct examination.⁶²⁰ Although there are a significant number of MATs and forecasts related to Direct Assessment activity during the rate case period, only seven of these forecasts are disputed: (1) ECDA indirect inspections; (2) ECDA direct examination; (3) ICDA engineering; (4) ICDA digs and Cal Advocates' suggestion of the continued use of the ICDA Memorandum Account (ICDAMA); (5) SCCDA engineering and surveys; (6) SCCDA digs; and (7) TIMP direct examinations. Each of these is addressed below.

3.4.2.1 ECDA Indirect Inspections – Expense (MAT HPC)

ECDA indirect inspections involve diagnostic testing to assess the threat of external corrosion on a pipeline.⁶²¹ Our opening testimony and workpapers describe this program and provide evidence demonstrating that the program and PG&E's cost forecast for the rate case period are prudent and reasonable.⁶²² TURN recommends a reduction to PG&E's forecast

⁶¹⁸ TURN-04, p. 33, lines 4-15.

⁶¹⁹ PG&E-16-E, p. 5-34, line 21 to p. 5-35, line 13.

⁶²⁰ PG&E-16-E, p. 5-36, line 16 to p. 5-37, line 3. A more detailed discussion of each Direct Assessment method is provided in PG&E-03, pp. 5-38, line 3 to 5-49, line 23.

⁶²¹ PG&E-16-E, p. 5-37, lines 6-10.

⁶²² PG&E-03, p. 5-38, line 3 to p. 5-41, line 10 and p. 5-42, line 1 to p. 5-43, line 7.

based on a lower unit cost forecast resulting from the use of a longer period of historical data (*i.e.*, 2014-2019) and a revised escalation factor:⁶²³

TABLE 3-16
ECDA INDIRECT INSPECTIONS (MAT HPC): PG&E’S EXPENSE FORECAST AND
PARTIES RECOMMENDED REDUCTIONS (\$000s)^(a)

Party	2020 Rec.	2021	2022	2023
PG&E	\$7,855	\$20,222	\$5,170	\$8,106
TURN				\$(339)
(a) PG&E-16-E, p. 5-89, Table 5-5, line 5 (PG&E’s 2020-2022 recorded and forecast costs); PG&E-3-ES, p. iii (PG&E’s 2023 forecast); PG&E-64, p. JCE 3-21 (TURN’s recommendation)				

TURN’s proposed reductions are not well founded. First, as PG&E explained in rebuttal testimony, the ECDA program underwent substantial changes between 2014 and 2016 and thus TURN’s use of actual cost data from the period before 2017 is inappropriate. PG&E’s use of 2017-2019 avoids the problems with data from earlier years.⁶²⁴ Second, TURN used the wrong escalation factor thus further compounding the problems with its unit cost forecast.⁶²⁵ TURN’s unit cost forecast should be rejected and PG&E’s forecast for ECDA indirect inspections should be adopted.

3.4.2.2 ECDA Direct Examination – Expense (MAT HPN)

After an ECDA inspection occurs, PG&E may perform an ECDA Direct Examination to further assess and evaluate external corrosion pipeline threats.⁶²⁶ Our opening testimony and workpapers describe the ECDA Direct Examination program and provide evidence

⁶²³ TURN-04, p. 35, lines 15-19.

⁶²⁴ PG&E-16-E, p. 5-38, lines 3-7.

⁶²⁵ PG&E-16-E, p. 5-38, lines 8-28.

⁶²⁶ PG&E-16-E, p. 5-39, lines 5-9.

demonstrating that the program and PG&E's cost forecast for the rate case period are prudent and reasonable.⁶²⁷ The parties' proposed forecasts for this program are:

TABLE 3-17
ECDA DIRECT EXAMINATION (MAT HPN): PG&E'S EXPENSE FORECAST AND PARTIES
RECOMMENDED REDUCTIONS (\$000s)^(a)

Party	2020 Rec.	2021	2022	2023
PG&E	\$12,739	\$18,516	\$17,223	\$34,394
Cal Advocates				\$(19,719)
TURN				\$0 ^(b)
(a) PG&E-16-E, p. 5-89, Table 5-5, line 13 (PG&E's 2020-2022 recorded and forecast costs); PG&E-3-ES, p. iii (PG&E's 2023 forecast); CALPA-02, p. 20, Table 2-17 (calculated as \$34.394-\$14.675=\$19.719); PG&E-64, p. JCE 3-21 (TURN's recommendation). (b) TURN's recommendation for MAT HPN was \$34.712 million which is higher than PG&E's most current forecast included in Exhibit PG&E 3-ES (as of August 19, 2022). PG&E is reflecting TURN's proposed reduction as \$0 rather than an increase to PG&E's proposed forecast.				

TURN recommends a reduction to PG&E's forecast based on TURN's lower unit cost projection.⁶²⁸ However, TURN's lower unit cost projection is based on the same flaws as described above in Section 3.4.2.1 for ECDA indirect inspections (i.e., inclusion of 2014-2016 cost data and an incorrect escalation factor). For the reasons explained above, TURN's proposed reduction should be rejected.

Cal Advocates recommends a much more substantial reduction to PG&E's forecast based on a decrease in forecasted digs and reliance on 2021 completed work data.⁶²⁹ Based on digs in prior years, Cal Advocates estimates that there will only be 1.1 digs per mile of ECDA inspection. Cal Advocates uses this estimate to arrive at a substantially lower number of digs expected during the rate case period.⁶³⁰ Cal Advocates' estimate is flawed because it does not

⁶²⁷ PG&E-03, p. 5-42, line 1 to p. 5-43, line 7; PG&E-3-E, WP 5-16; PG&E-03, WP 5-58 to WP 5-60.

⁶²⁸ TURN-04, p. 36, lines 7-12.

⁶²⁹ CALPA-02, p. 24, lines 1-5.

⁶³⁰ PG&E-16-E, p. 5-40, lines 18-20; CALPA-02, p. 24, Table 2-20 and p. 27, line 12 to p. 28, line 10.

consider the specific work to be performed on pipelines that will be subject to ECDA inspections.

In contrast to Cal Advocates' approach, PG&E developed its ECDA dig forecast based on a project-by-project review of ECDA inspections that would occur during the rate case period using a standard procedure to calculate the number of digs per project based on specific characteristics such as pipe length and types of threats. In its rebuttal testimony, PG&E provided several examples showing how the number of digs was specifically calculated for each project.⁶³¹ At the hearing, Cal Advocates pointed out several ECDA projects where there were fewer digs than required by PG&E's standard procedure.⁶³² However, this occurred in a limited number of instances. Cal Advocates failed to show that PG&E does not generally follow the procedure used to develop the ECDA dig forecast. Moreover, Cal Advocates' own testimony demonstrates the significant variability in the number of ECDA digs per project.⁶³³ This variability supports the more detailed project-by-project analysis proposed by PG&E rather than the generic 1.1 digs/mile estimate developed by Cal Advocates.

3.4.2.3 ICDA Engineering – Expense (MAT HPJ)

To perform ICDA engineering, PG&E analyzes construction records, O&M histories, pipeline features, and other inspection reports to determine the feasibility of conducting ICDA on a pipe.⁶³⁴ Our opening testimony and workpapers describe the ICDA Engineering program and provide evidence demonstrating that the program and PG&E's cost forecast for the rate case

⁶³¹ PG&E-16-E, p. 5-40, line 22 to p. 5-41, line 27; p. 5-42, lines 3-8.

⁶³² Tr. Vol. 5, 916:5-8, PG&E/Barnes, referencing CALPA-02, p. 26, Table 2-21.

⁶³³ PG&E-16-E, p. 5-42, lines 17-23.

⁶³⁴ PG&E-16-E, p. 5-42, line 27 to p. 5-43, line 3.

period are prudent and reasonable.⁶³⁵ Cal Advocates agrees with PG&E’s ICDA engineering forecast.⁶³⁶ TURN, on the other hand, proposes reducing PG&E’s forecast:

TABLE 3-18
ICDA ENGINEERING (MAT HPJ): PG&E’S EXPENSE FORECAST AND PARTIES
RECOMMENDED REDUCTIONS (\$000s)^(a)

Party	2020 Rec.	2021	2022	2023
PG&E	\$215	\$150	\$150	\$812
TURN				\$(141)

(a) PG&E-16-E, p. 5-89, Table 5-5, line 10 (PG&E’s 2020-2022 recorded and forecast costs); PG&E-3-ES, p. iii (PG&E’s 2023 forecast); PG&E-64, p. JCE 3-22 (TURN’s recommendation)

Similar to its ECDA arguments, TURN proposes using earlier years (i.e., 2014-2016) to establish a unit cost forecast.⁶³⁷ However, similar to TURN’s ECDA unit cost forecast, this approach is flawed because the ICDA procedures substantially changed after 2016 and thus the costs incurred between 2017 and 2019, which were used by PG&E, more accurately reflect the costs resulting from the revised ICDA procedures.⁶³⁸ PG&E’s unit cost forecast is more accurate and thus should be used to determine ICDA engineering costs.

3.4.2.4 ICDA Digs – Expense (MAT HPO)

ICDA digs include excavations and direct examinations of the pipeline to determine whether metal loss as a result of internal corrosion has occurred, as well as evaluation of remaining pipeline strength and performing remediation.⁶³⁹ Our opening testimony and workpapers describe the ICDA digs program and explains why the program and PG&E’s cost

⁶³⁵ PG&E-03, p. 5-43, line 8 to p. 5-44, line 12; PG&E-3-E, WP 5-20 to WP 5-21; PG&E-03, WP 5-58 to WP 5-60 and WP 5S-1 to WP 5S-3.

⁶³⁶ CALPA-02, p. 28, lines 20-22.

⁶³⁷ TURN-04, p. 35, lines 4-6.

⁶³⁸ PG&E-16-E, p. 5-43, lines 18-25.

⁶³⁹ PG&E-16-E, p. 5-44, lines 5-9.

forecast for the rate case period are prudent and reasonable.⁶⁴⁰ The parties’ proposed forecasts for this program are:

TABLE 3-19
ICDA DIGS (MAT HPO): PG&E’S EXPENSE FORECAST AND PARTIES RECOMMENDED REDUCTIONS (\$000s)^(a)

Party	2020 Rec.	2021	2022	2023
PG&E	\$5,663	\$20,377	\$20,377	\$12,900
Cal Advocates ^(b)				\$(12,900)
TURN				\$(1,071)

(a) PG&E-16-E, p. 5-89, Table 5-5, line 14 (PG&E’s 2020-2022 recorded and forecast costs); PG&E-3-ES, p. iii (PG&E’s 2023 forecast); PG&E-64, p. JCE 3-21 (TURN’s recommendation).

(b) Cal Advocates’ recommended disallowance for MAT HPO is unspecified. See CALPA-02, pp. 28-30.

TURN recommends reducing PG&E’s forecast based on the use of data from 2014-2019 for unit costs rather than the 2017-2019 time period used by PG&E.⁶⁴¹ For the reasons explained above in Sections 3.4.2.1 and 3.4.2.3, given the changes in ICDA, use of 2014-2016 data is not appropriate. Instead, the Commission should adopt PG&E’s forecast which is based on 2017-2019 data.⁶⁴²

Cal Advocates also addresses ICDA digs, but it does not quantify a reduction in PG&E’s forecast. Instead, Cal Advocates generically argues that PG&E’s forecast is “inadequately supported.”⁶⁴³ Cal Advocates essentially ignores the detailed workpapers that support the forecast and demonstrate its reasonableness.⁶⁴⁴

⁶⁴⁰ PG&E-03, p. 5-43, line 8 to p. 5-44, line 12; PG&E-3-E, WP 5-20 to WP 5-21; PG&E-03, WP 5S-1 to WP 5S-3.

⁶⁴¹ TURN-04, p. 35, lines 4-6.

⁶⁴² PG&E-16-E, p. 5-44, lines 16-26.

⁶⁴³ CALPA-02, p. 29, line 3 to p. 30, line 17.

⁶⁴⁴ PG&E-3-E, WP 5-20 to WP 5-21 (workpapers supporting PG&E’s ICDA digs and costs); see also PG&E-16-E, p. 5-45, lines 5-9.

Cal Advocates also points to cost data from 2019-2021 and argues that PG&E's forecast is higher than historical costs.⁶⁴⁵ But the data that Cal Advocates relies on includes fewer digs than PG&E is forecasting for the rate case period and thus the total costs in 2019-2021 will naturally be lower than the 2023 forecasted costs. Because the total costs of direct examinations increase as the number of digs increase, it is entirely reasonable that the 2023 forecast is higher than the 2019-2021 actual costs.⁶⁴⁶

Cal Advocates' analysis also does not adequately consider a new PHMSA interpretation which was issued on June 23, 2021 and which will result in increased ICDA dig costs. PHMSA's recent interpretation is not reflected in 2021 costs because much of the work in 2021 was planned or performed before the interpretation was issued.⁶⁴⁷ Thus, in addition to an increased number of digs, costs in 2023 will increase as a result of PHMSA's new regulatory interpretation. Both of these factors support PG&E's forecast.

Finally, it is notable that Cal Advocates does not offer its own forecast for ICDA dig costs. Instead, Cal Advocates suggests that PG&E continue to use the ICDA Memorandum Account (ICDAMA) to track ICDA costs.⁶⁴⁸ However, as PG&E explained in rebuttal testimony, this argument is based on a misunderstanding of the purpose of the ICDAMA. The ICDAMA was originally adopted by the Commission because in prior rate cases PG&E had re-allocated adopted ICDA forecasts for TIMP strength tests. The ICDAMA was intended to provide a tracking mechanism for ICDA expenditures.⁶⁴⁹ In this case, however, there is no claim that adopted ICDA forecasts have been re-allocated for work on other programs and, in

⁶⁴⁵ CALPA-02, p. 29, lines 7-22 and p. 30, Table 2-23.

⁶⁴⁶ PG&E-16-E, p. 5-45, lines 10-21.

⁶⁴⁷ PG&E-16-E, p. 5-45, line 22 to p. 5-46, line 17.

⁶⁴⁸ PG&E-16-E, p. 5-46, lines 18-28; CALPA-02, p. 30, lines 14-17.

⁶⁴⁹ PG&E-16-E, p. 5-47, lines 1-10, citing D.19-09-025, pp. 143, 145.

fact, PG&E has been spending more on ICDA than the adopted forecasts for certain years.⁶⁵⁰ Thus, there is no reason to continue to ICDAMA because the purpose for this memorandum account no longer exists. The ICDAMA is addressed in more detail below in Section 3.4.9.

3.4.2.5 SCCDA Engineering and Surveys – Expense (MAT HPK)

SCCDA engineering and surveys are used to proactively address axial stress corrosion cracking on gas pipelines where the likelihood of stress corrosion cracking has been determined to be low to moderate.⁶⁵¹ Our opening testimony and workpapers describe the SCCDA Engineering and Surveys program and provide evidence demonstrating that the program and PG&E’s cost forecast for the rate case period are prudent and reasonable.⁶⁵² The parties’ proposed forecasts for this program are:

TABLE 3-20
SCADA ENGINEERING AND SURVEYS (MAT HPK): PG&E’S EXPENSE FORECAST AND PARTIES RECOMMENDED REDUCTIONS (\$000s)^(a)

Party	2020 Rec.	2021	2022	2023
PG&E	\$--	\$500	\$500	\$1,971
Cal Advocates				\$(1,922)
TURN				\$(341)

(a) PG&E-16-E, p. 5-89, Table 5-5, line 11 (PG&E’s 2020-2022 recorded and forecast costs); PG&E-3-ES, p. iii (PG&E’s 2023 forecast); CALPA-02, p. 35, line 3 (calculated as \$1.971-\$0.496=\$1.475); and PG&E-64, p. JCE 3-22 (TURN’s recommendation).

TURN recommends a reduction to PG&E’s forecast based on lower unit costs.⁶⁵³ This proposal is based on the same mistaken arguments that TURN used to support ECDA unit cost reductions. TURN’s proposal on the ECDA unit cost reduction is addressed in Section 3.4.2.1 above.

⁶⁵⁰ PG&E-16-E, p. 5-47, lines 8-15.

⁶⁵¹ PG&E-16-E, p. 5-47, lines 24-26.

⁶⁵² PG&E-03, p. 5-44, line 13 to p. 5-45, line 13; PG&E-3-E, WP 5-22 to WP 5-23.

⁶⁵³ TURN-04, p. 37, lines 1-4.

Cal Advocates proposes a reduction which essentially eliminates this program.⁶⁵⁴ To support this drastic reduction, Cal Advocates first makes the generic argument that PG&E has not supported its forecast.⁶⁵⁵ In workpapers and discovery, PG&E provided to Cal Advocates detailed information regarding the support for PG&E's forecast. Cal Advocates simply ignores this information.⁶⁵⁶ Cal Advocates also uses 11 months of actual 2021 cost data to support its proposed reduction. However, the 2021 data only reflects two (2) SCCDA projects.⁶⁵⁷ In this rate case, PG&E is proposing 19 SCCDA projects a year and our workpapers identify the specific projects we intend to undertake.⁶⁵⁸ Given the substantial expansion in SCCDA projects during the rate case period, it is entirely reasonable that PG&E's cost forecast would be substantially higher than the 2021 actual costs.

3.4.2.6 SCCDA Digs – Expense (MAT HPP)

SCCDA digs involve excavating and exposing pipeline segments in selected locations based on the SCCDA engineering analysis.⁶⁵⁹ Our opening testimony and workpapers describe the SCCDA digs program and provide evidence demonstrating that the program and PG&E's cost forecast for the rate case period are prudent and reasonable.⁶⁶⁰ The parties' proposed forecasts for this program are:

⁶⁵⁴ PG&E-16-E, p. 5-48, lines 19-23; CALPA-02, p. 34, line 17 to p. 35, line 3.

⁶⁵⁵ CALPA-02, p. 34, line 23.

⁶⁵⁶ PG&E-03-E, WP 5-22 to WP 5-23 (workpapers supporting PG&E's forecast); see also PG&E-16-E, p. 5-49, lines 1-11.

⁶⁵⁷ CALPA-02, p. 34, line 23 to p. 35, line 3.

⁶⁵⁸ PG&E-16-E, p. 5-49, lines 12-29.

⁶⁵⁹ PG&E-16-E, p. 5-50, lines 7-13.

⁶⁶⁰ PG&E-03, p. 5-44, line 13 to p. 5-45, line 13; PG&E-3-E, WP 5-22 to WP 5-23.

TABLE 3-21
SCCDA DIGS (MAT HPP): PG&E’S EXPENSE FORECAST AND PARTIES RECOMMENDED
REDUCTIONS (\$000s)^(a)

Party	2020 Rec.	2021	2022	2023
PG&E	\$0	\$2,030	\$8,120	\$16,208
Cal Advocates				\$(15.310)
TURN				\$(298)

(a) PG&E-16-E, p. 5-89, Table 5-5, line 15 (PG&E’s 2020-2022 recorded and forecast costs); PG&E-3-ES, p. iii (PG&E’s 2023 forecast); CALPA-02, p. 35, line 2 (calculated as \$16.208-\$0.898=\$15.310); and PG&E-64, p. JCE 3-21 (TURN’s recommendation).

TURN recommends a reduction to PG&E’s forecast based on lower unit costs.⁶⁶¹ This proposal is based on the same mistaken arguments that TURN used to support ECDA unit cost reductions. TURN’s proposal on the ECDA unit cost reduction is addressed in Section 3.4.2.1 above.

Similar to SCCDA Engineering and Surveys described above in Section 3.4.2.5, Cal Advocates proposes a forecast reduction which essentially eliminates this program.⁶⁶² To support this drastic reduction, Cal Advocates again makes the generic argument that PG&E has not supported its forecast.⁶⁶³ In workpapers and discovery, PG&E provided to Cal Advocates detailed information regarding the support for PG&E’s forecast. Cal Advocates simply ignores this information.⁶⁶⁴ In addition, SCCDA costs were lower in 2020 and 2021 because no SCC threats were due for assessment in these years. However, there are SCC threats that need to be addressed during the rate case period and thus the forecast costs for that time period are reasonably higher to cover these SCC threat assessments.⁶⁶⁵

⁶⁶¹ TURN-04, p. 37, lines 1-4.

⁶⁶² PG&E-16-E, p. 5-50, line 24 to p. 5-51, line 2; CALPA-02, p. 33, line 9 to p. 34, line 15.

⁶⁶³ CALPA-02, p. 34, lines 1-2.

⁶⁶⁴ PG&E-03-E, WP 5-22 to WP 5-23 (workpapers supporting PG&E’s forecast); see also PG&E-16-E, p. 5-51, lines 3-22.

⁶⁶⁵ PG&E-16-E, p. 5-51, line 23 to p. 5-52, line 6.

3.4.2.7 TIMP Direct Examinations – Expense (MAT HPU)

TIMP direct examinations involve excavating a pipe section, removing the coating, and inspecting all pipe surfaces.⁶⁶⁶ Our opening testimony and workpapers describe the TIMP Direct Examinations program and provide evidence demonstrating that the program and PG&E’s cost forecast for the rate case period are prudent and reasonable.⁶⁶⁷ Cal Advocates is the only party disputing PG&E’s forecast for this program:

TABLE 3-22
TIMP DIRECT EXAMINATIONS (MAT HPU): PG&E’S EXPENSE FORECAST AND PARTIES
RECOMMENDED REDUCTIONS (\$000s)^(a)

Party	2020 Rec.	2021	2022	2023
PG&E	\$9,381	\$11,747	\$11,747	\$23,965
Cal Advocates				\$(13,560)
(a) PG&E-16-E, p. 5-89, Table 5-5, line 15 (PG&E’s 2020-2022 recorded and forecast costs); PG&E-3-ES, p. iii (PG&E’s 2023 forecast); CALPA-02, p. 30, line 23 (calculated as \$23,965- \$10,405=\$13,560).				

Cal Advocates initially argues that the 2020 actual costs should be sufficient for 2023 going forward.⁶⁶⁸ However, the scope of the 2023 program is over double what was completed in 2020 and thus the 2023 forecast is appropriately higher than the 2020 actual costs.⁶⁶⁹

Cal Advocates also asserts that PG&E has represented that it is eliminating direct examination, and thus the forecast for this program should be substantially reduced.⁶⁷⁰ Cal Advocates’ argument is based on a misunderstanding of PG&E’s statements. PG&E is not proposing to eliminate the direct examination program but simply stated that it was moving away from “use of direct assessment as the sole integrity assessment method for [gas transmission]

⁶⁶⁶ PG&E-16-E, p. 5-52, lines 12-16.

⁶⁶⁷ PG&E-03, p. 5-45, line 14 to p. 5-47, line 2; PG&E-3-E, WP 5-24 to WP 5-26; PG&E-03, WP 5S-4 to WP 5S-6.

⁶⁶⁸ CALPA-02, p. 32, lines 10-13.

⁶⁶⁹ PG&E-16-E, p. 5-53, lines 3-9.

⁶⁷⁰ CALPA-02, p. 31, line 20 to p. 32, line 4.

pipelines.”⁶⁷¹ While PG&E is moving away from using direct assessment as the sole pipeline integrity assessment method, it certainly does not plan on abandoning direct assessment methods, including the direct examination sub-program, altogether.

Finally, contrary to Cal Advocates’ assertions, PG&E provided testimony regarding the impact of the recent PHMSA interpretation on PG&E’s forecast, which also explains why PG&E’s 2023 forecast is higher than 2020 and 2021 actual costs.⁶⁷²

3.4.3 Strength Testing (MWCs HP and 75)

Strength tests are conducted on gas transmission pipelines to assess integrity and for purposes of determining or verifying the appropriate maximum allowable operating pressure (MAOP). PG&E’s Strength Testing Program includes three sub-programs: (1) strength testing for non-TIMP purposes as required by federal law and California statutory requirements; (2) strength testing for TIMP purposes as required by federal law; and (3) strength testing associated with liquified and compressed natural gas.⁶⁷³ TURN is the only party that disputes PG&E’s Strength Testing Program forecasts. Specifically, TURN disputes the following sub-programs: (1) non-TIMP strength testing capital expenditures; (2) non-TIMP pipeline replacement in lieu of strength testing capital; (3) non-TIMP pipeline replacement in lieu of strength testing expense; (4) TIMP strength testing expense; (5) TIMP replacement in lieu of strength testing expense; and (6) TIMP replacement in lieu of strength testing capital. Each of these sub-programs is addressed below.

3.4.3.1 Non-TIMP Strength Testing – Capital (MAT 75U)

The Non-TIMP strength testing sub-program validates the integrity of gas pipelines by strength testing in accordance with federal regulations for certain specific pipelines (e.g., pipelines lacking a traceable, verifiable, and complete (TVC) record, pipelines needing

⁶⁷¹ PG&E-16-E, p. 5-53, lines 10-14.

⁶⁷² PG&E-03, p. 5-40, lines 3-7; CALPA-02, p. 32, lines 5-8.

⁶⁷³ PG&E-16-E, p. 5-53, line 25 to p. 5-54, line 13.

MAOP reconfirmation).⁶⁷⁴ Our opening testimony and workpapers describe the Non-TIMP Strength Testing program and provide evidence demonstrating that the program and PG&E's cost forecast for the rate case period are prudent and reasonable.⁶⁷⁵ The parties' proposed cost forecasts for this sub-program are:

TABLE 3-23
NON-TIMP STRENGTH TESTING (MAT 75U): PG&E'S CAPITAL FORECAST AND
PARTIES RECOMMENDED REDUCTIONS (\$000s)^(a)

Party	2020 Rec.	2021	2022	2023	2024	2025	2026
PG&E	\$--	\$--	\$--	\$73,325	\$75,162	\$77,268	\$79,657
TURN				\$(11,369)			
(a) PG&E-16-E, p. 5-91, Table 5-6, line 23 (PG&E's 2020-2022 recorded and forecast costs); PG&E-3-ES, p. v (PG&E's 2023-2026 forecast); PG&E-64, p. JCE 3-13 (TURN's recommendation)							

TURN's proposed reduction is based on: (1) a different method for determining strength testing costs that have been disallowed; (2) use of a different cost model; and (3) removal of certain projects based on TURN's argument that these projects do not have compliance deadlines during the rate case period.⁶⁷⁶ These three arguments are not supported by the evidence, as explained in more detail below.

First, TURN argues that the amount of pipeline subject to disallowances approved by the Commission in prior proceedings.⁶⁷⁷ PG&E does not dispute that it cannot recover costs for pipe installed after December 31, 1955 that lacks a TVC record of a strength test. The question is how much of the pipe forecasted for non-TIMP strength testing is subject to this disallowance. TURN first argues that PG&E should have excluded 13.84 miles of TIMP strength tests from PG&E's disallowance calculation because disallowance applies to non-TIMP strength tests, not

⁶⁷⁴ PG&E-16-E, p. 5-54, line 16 to p. 5-55, line 6.

⁶⁷⁵ PG&E-03, p. 5-61, line 10 to p. 5-64, line 12; PG&E-3-ES, WP 5S-15.

⁶⁷⁶ TURN-04, p. 38, line 1 to p. 45, line 18.

⁶⁷⁷ PG&E-16-E, p. 5-55, line 23 to p. 5-56, line 9; TURN-04, p. 39, lines 7-12.

TIMP strength tests.⁶⁷⁸ PG&E agrees with TURN's recommendation and proposes to adjust its forecast accordingly upon issuance of a Commission decision on this issue.⁶⁷⁹

TURN also argues that the disallowance percentage factor used by PG&E is flawed. TURN instead argues that a project-by-project analysis should be performed rather than applying a percentage to all projects.⁶⁸⁰ Notably, the percentage methodology was used by PG&E in this proceeding is the same methodology that was used the 2019 GT&S rate case, which no party opposed and the Commission implicitly approved.⁶⁸¹ In addition, the list of rate case period projects identified by PG&E is subject to change. Thus, TURN's project-by-project analysis may not accurately reflect the actual projects that are performed during the rate case period. In these circumstances, use of a percentage factor rather than a project-by-project analysis is more appropriate.⁶⁸²

Second, TURN proposes using a different cost model based on information provided during discovery and different coefficients.⁶⁸³ TURN's regression analysis results in an R-squared value of 0.726, which is less accurate than PG&E's regression analysis which results in an R-squared value of 0.735. Because PG&E's regression analysis is a more accurate fit with the historical data, TURN's proposed analysis should be rejected.⁶⁸⁴

Third, TURN argues that because non-TIMP strength tests do not have specific compliance deadlines under California state law (i.e., PUC § 958), PG&E should not conduct

⁶⁷⁸ TURN-04, p. 39, lines 7-13.

⁶⁷⁹ PG&E-16-E, p. 5-56, line 12-18.

⁶⁸⁰ PG&E-16-E, p. 5-56, lines 3-9, lines 19-21; TURN-04, p. 39, line 14 to p. 43, line 2.

⁶⁸¹ PG&E-16-E, p. 5-56, lines 21-24 citing D.19-09-025, pp. 155-159.

⁶⁸² PG&E-16-E, p. 5-56, line 24 to p. 5-57, line 3.

⁶⁸³ PG&E-16-E, p. 5-57, lines 5-9; TURN-04, p. 46, lines 5-7.

⁶⁸⁴ PG&E-16-E, p. 5-57, lines 9-15.

non-TIMP strength tests during the rate case period for pipes operating below 20 percent Specified Minimum Yield Strength (SMYS).⁶⁸⁵

While TURN is correct that the deadline for non-TIMP strength tests is beyond the rate case period⁶⁸⁶, it is neither reasonable nor prudent to wait until the last minute and try to cram in all of the strength testing just before the legal deadline. PG&E has developed a program that allows it to perform non-TIMP strength testing at a measured pace to achieve the compliance deadline. The forecast in this rate case reflects that measured pace.⁶⁸⁷ The Commission should adopt this forecast and reject TURN's "wait until the last minute" approach. TURN also argues that delaying non-TIMP strength testing is appropriate based on its flawed RSE and benefit-cost analysis and that PG&E should instead seek more cost-efficient alternatives.⁶⁸⁸ This argument ignores the nature of non-TIMP strength testing, which involves testing many short segments essentially reducing the RSE, which explains why the RSE is low for this program. TURN also glosses over the fact that non-TIMP strength testing is a legal compliance obligation under California statutory law and federal regulations, not an option.⁶⁸⁹ In addition, TURN's focus on SMYS highlights the likelihood of failure, but ignores the consequences of failure. By only focusing on one side of the risk equation, TURN understates the potential impact of non-TIMP strength testing on reducing risk.⁶⁹⁰

Finally, TURN vaguely suggests that PG&E should reduce the forecasted amount of non-TIMP strength testing and look for more "cost-efficient alternatives" (i.e., alternative assessment

⁶⁸⁵ PG&E-16-E, p. 5-57, lines 20-26; TURN-04, p. 48, line 12 to p. 49, line 26.

⁶⁸⁶ TURN mistakenly asserts that the deadline for these strength tests is 2035 based on California state law. However, TURN ignores federal regulations which establish a 2028 deadline for strength tests on certain pipes is required by 2028. See PG&E-16-E, p. 5-58, lines 11-17.

⁶⁸⁷ PG&E-16-E, p. 5-58, lines 17-30.

⁶⁸⁸ TURN-04, p. 49, lines 1-26.

⁶⁸⁹ PG&E-16-E, p. 5-59, lines 5-14.

⁶⁹⁰ PG&E-16-E, p. 5-59, line 15 to p. 5-60, line 9.

methodologies).⁶⁹¹ This ignores the undisputed fact that non-TIMP strength testing or replacement in lieu of strength testing is required by California statutory law and federal regulations.⁶⁹²

3.4.3.2 Non-TIMP Pipeline Replacement in Lieu of Strength Testing – Capital (MAT 75R)

When a pipeline replacement is more cost-effective than performing a non-TIMP strength test, PG&E replaces the pipeline under its non-TIMP Pipeline Replacement program.⁶⁹³

Pipeline replacement is not an “alternative” assessment methodology, but rather the wholesale replacement of a pipe instead of performing strength testing. Our opening testimony and workpapers describe the Non-TIMP pipeline replacement program and provide evidence demonstrating that the program and PG&E’s cost forecast for the rate case period are prudent and reasonable.⁶⁹⁴ The parties’ proposed cost forecasts for this sub-program are:

TABLE 3-24
NON-TIMP PIPELINE REPLACEMENT IN LIEU OF STRENGTH TESTING (MAT 75R):
PG&E’S CAPITAL FORECAST AND PARTIES RECOMMENDED REDUCTIONS (\$000s)^(a)

Party	2020 Rec.	2021	2022	2023	2024	2025	2026
PG&E	\$31,466	\$35,340	\$21,716	\$66,653	\$68,322	\$70,237	\$72,408
TURN				\$(30,573)			

(a) PG&E-16-E, p. 5-91, Table 5-6, line 15 (PG&E’s 2020-2022 recorded and forecast costs); PG&E-3-ES, p. v (PG&E’s 2023-2026 forecast); PG&E-64, p. JCE 3-13 (TURN’s recommendation).

TURN’s proposed reduction is based on: (1) a different method for determining strength testing costs that have been disallowed; (2) use of a different cost model; and (3) removal of certain projects based on TURN’s argument that these projects do not have compliance deadlines during the rate case period.⁶⁹⁵ TURN’s arguments regarding disallowance percentages (Item

⁶⁹¹ TURN-04, p. 49, lines 25-26.

⁶⁹² PG&E-16-E, p. 5-60, lines 10-18.

⁶⁹³ PG&E-16-E, p. 5-61, lines 1-2.

⁶⁹⁴ PG&E-03, p. 5-66, line 3 to p. 5-67, line 25; WP 5S-16.

⁶⁹⁵ PG&E-16-E, p. 5-61, lines 6-20; TURN-04, p. 38, line 1 to p. 45, line 18.

#1) and removal of projects that compliance deadlines during the rate case period (Item #3) are addressed above in Section 3.4.3.1.

With regard to TURN's use of a different cost model for non-TIMP replacements (Item #2), this proposal has very little impact on the total forecasted costs.⁶⁹⁶ More importantly, similar to TURN's proposed cost model for non-TIMP strength testing, TURN's proposed cost model for pipeline replacements is less accurate (i.e., has a lower R-squared value) than the cost model proposed by PG&E.⁶⁹⁷ Given that TURN's proposed cost model less accurately reflects historical recorded data, TURN's cost model should be rejected.

3.4.3.3 Non-TIMP Pipeline Replacement in Lieu of Strength Testing - Expense (MAT JT6)

In addition to capital costs incurred by PG&E for non-TIMP replacement (described above in Section 3.4.3.2), PG&E also incurs expense costs related to these projects. Our opening testimony and workpapers describe the Non-TIMP pipeline replacement program and provide evidence demonstrating that the program and PG&E's cost forecast for the rate case period are prudent and reasonable.⁶⁹⁸ The parties' proposed cost forecasts for this sub-program are:

TABLE 3-25
NON-TIMP PIPELINE REPLACEMENT IN LIEU OF STRENGTH TESTING (MAT JT6):
PG&E'S EXPENSE FORECAST AND PARTIES RECOMMENDED REDUCTIONS (\$000s)^(a)

Party	2020 Rec.	2021	2022	2023
PG&E	\$5,679	\$6,200	\$14,271	\$35,443
TURN				\$(24,821)
(a) PG&E-16-E, p. 5-89, Table 5-5, line 25 (PG&E's 2020-2022 recorded and forecast costs); PG&E-3-ES, p. iii (PG&E's 2023 forecast); PG&E-64, p. JCE 3-25 (TURN's recommendation).				

TURN's proposed reduction is based on: (1) a different method for determining strength testing costs that have been disallowed; (2) use of a different cost model; and (3) removal of

⁶⁹⁶ PG&E-16-E, p. 5-61, lines 21-28.

⁶⁹⁷ PG&E-16-E, p. 5-62, lines 1-9.

⁶⁹⁸ PG&E-03, p. 5-56, line 1 to p. 5-57, line 13; PG&E-3-ES, WP 5-35; PG&E-03, WP 5S-12.

certain projects based on TURN's argument that these projects do not have compliance deadlines during the rate case period.⁶⁹⁹ TURN's arguments regarding disallowance percentages (Item #1) and removal of projects that compliance deadlines during the rate case period (Item #3) are addressed above in Section 3.4.3.1.

With regard to the cost model, TURN uses the same modeling approach as PG&E but adds in 2021 carryover costs. Because TURN's proposal only impacts a single project, its cost model changes for non-Time pipeline replacement expenses has a de minimus impact on PG&E's forecast.⁷⁰⁰ The main drivers for TURN's reduction are the disallowance methodology and delaying projects that do not have a compliance deadline. These issues are addressed above.

3.4.3.4 TIMP Strength Testing – Expense (MAT HPF)

TIMP strength tests validate the integrity of pipe that is located in HCAs, Class 3 and 4 non-HCAs, and potentially in MCAs. These tests are prescribed and required under federal law.⁷⁰¹ Our opening testimony and workpapers describe the TIMP strength testing program and provide evidence demonstrating that the program and PG&E's cost forecast for the rate case period are prudent and reasonable.⁷⁰² The parties' proposed cost forecasts for this sub-program are:

⁶⁹⁹ PG&E-16-E, p. 5-62, line 25 to p. 5-63, line 3; TURN-04, p. 38, line 1 to p. 45, line 18.

⁷⁰⁰ PG&E-16-E, p. 5-63, lines 4-11.

⁷⁰¹ PG&E-16-E, p. 5-63, lines 13-21.

⁷⁰² PG&E-03, p. 5-57, line 14 to p. 5-59, line 5; PG&E-3-ES, WP 5-36; PG&E-03, WP 5S-13.

TABLE 3-26
TIMP STRENGTH TESTING (MAT HPF): PG&E’S EXPENSE FORECAST AND PARTIES
RECOMMENDED REDUCTIONS (\$000s)^(a)

Party	2020 Rec.	2021	2022	2023
PG&E	\$20,059	\$41,929	\$60,456	\$19,917
TURN				\$0 ^(b)
(a) PG&E-16-E, p. 5-89, Table 5-5, line 7 (PG&E’s 2020-2022 recorded and forecast costs); PG&E-3-ES, p. iii (PG&E’s 2023 forecast); PG&E-64, p. JCE 3-21 (TURN’s recommendation). (b) TURN’s recommendation for MAT HPN was \$20.141 million which is higher than PG&E’s most current forecast included in Exhibit PG&E 3-ES (as of August 19, 2022). PG&E is reflecting TURN’s proposed reduction as \$0 rather than an increase to PG&E’s proposed forecast.				

TURN’s proposed reduction is based on application of a different cost model and the removal of certain projects based on TURN’s argument that these projects do not have compliance deadlines during the rate case period.⁷⁰³ TURN’s arguments on these two issues are addressed above in Section 3.4.3.1.

3.4.3.5 TIMP Replacement in Lieu of Strength Testing – Expense (MAT HPM)

TIMP replacements are used when replacement is a more cost-effective option instead of strength testing.⁷⁰⁴ This program represents the expense portion of pipe replacements in lieu of TIMP strength testing. Our opening testimony and workpapers describe the TIMP replacement program and provide evidence demonstrating that the program and PG&E’s cost forecast for the rate case period are prudent and reasonable.⁷⁰⁵ The parties’ proposed cost forecasts for this sub-program are:

⁷⁰³ PG&E-16-E, p. 5-62, line 25 to p. 5-63, line 3; TURN-04, p. 38, line 1 to p. 45, line 18.

⁷⁰⁴ PG&E-16-E, p. 5-64, lines 13-16.

⁷⁰⁵ PG&E-03, p. 5-59, line 6 to p. 5-60, line 15; PG&E-3-ES, WP 5-37.

TABLE 3-27
TIMP REPLACEMENT IN LIEU OF STRENGTH TESTING (MAT HPM): PG&E’S EXPENSE
FORECAST AND PARTIES RECOMMENDED REDUCTIONS (\$000s)^(a)

Party	2020 Rec.	2021	2022	2023
PG&E	\$123	\$250	\$0	\$4,153
TURN				\$0 ^(b)
(a) PG&E-16-E, p. 5-89, Table 5-5, line 12 (PG&E’s 2020-2022 recorded and forecast costs); PG&E-3-ES, p. iii (PG&E’s 2023 forecast); PG&E-64, p. JCE 3-22 (TURN’s recommendation). (b) TURN’s recommendation for MAT HPM was \$4.237 million which is higher than PG&E’s most current forecast included in Exhibit PG&E 3-ES (as of August 19, 2022). PG&E is reflecting TURN’s proposed reduction as \$0 rather than an increase to PG&E’s proposed forecast.				

TURN’s proposed reduction is based on: (1) a different method for determining strength testing costs that have been disallowed; (2) use of a different cost model; and (3) removal of certain projects based on TURN’s argument that these projects do not have compliance deadlines during the rate case period.⁷⁰⁶ TURN’s arguments regarding disallowance percentages (Item #1) and removal of projects that compliance deadlines during the rate case period (Item #3) are addressed above in Section 3.4.3.1. With regard to the cost model, TURN uses the same modeling approach as PG&E but adds in 2021 carry over costs. Because TURN’s proposal only impacts a single project, its cost model changes for non-Time pipeline replacement expenses has a de minimus impact on PG&E’s forecast.⁷⁰⁷

3.4.3.6 TIMP Replacement in Lieu of Strength Testing – Capital (MAT 75Q)

TIMP replacements are used when replacement is a more cost-effective option instead of strength testing.⁷⁰⁸ This program represents the capital portion of pipe replacements in lieu of TIMP strength testing. Our opening testimony and workpapers describe the TIMP replacement program and provide evidence demonstrating that the program and PG&E’s cost forecast for the

⁷⁰⁶ PG&E-16-E, p. 5-64, line 26 to p. 5-65, line 1; TURN-04, p. 38, line 1 to p. 45, line 18.

⁷⁰⁷ PG&E-16-E, p. 5-65, lines 4-11.

⁷⁰⁸ PG&E-16-E, p. 5-65, lines 14-17.

rate case period are prudent and reasonable.⁷⁰⁹ The parties’ proposed cost forecasts for this sub-program are:

TABLE 3-28
TIMP REPLACEMENT IN LIEU OF STRENGTH TESTING (MAT 75Q): PG&E’S CAPITAL FORECAST AND PARTIES RECOMMENDED REDUCTIONS (\$000s)^(a)

Party	2020 Rec.	2021	2022	2023	2024	2025	2026
PG&E	\$3,305	\$6,100	\$--	\$17,899	\$18,347	\$18,861	\$19,445
TURN				\$0			

(a) PG&E-16-E, p. 5-91, Table 5-6, line 14 (PG&E’s 2020-2022 recorded and forecast costs); PG&E-3-ES, p. v (PG&E’s 2023-2026 forecast); PG&E-64, p. JCE 3-13 (TURN’s recommendation).
(b) TURN’s recommendation for MAT HPN was \$18.038 million which is higher than PG&E’s most current forecast included in Exhibit PG&E 3-ES (as of August 19, 2022). PG&E is reflecting TURN’s proposed reduction as \$0 rather than an increase to PG&E’s proposed forecast.

TURN’s proposed reduction is based on: (1) use of a different cost model; and (2) removal of certain projects based on TURN’s argument that these projects do not have compliance deadlines during the rate case period.⁷¹⁰ TURN’s arguments on these two issues are addressed above in Section 3.4.3.1.

3.4.4 Vintage Pipe Replacement – Capital (MWC 75E)

PG&E’s vintage pipe replacement program targets the threat posed by the presence of construction defects as they interact with outside forces such as land movement. PHMSA has urged gas pipeline operators to evaluate this threat and a recent incident outside of California, as well as industry groups developing best practices, have highlighted the importance of addressing the risks created land movement.⁷¹¹ During the rate case period, PG&E proposes to replace approximately 0.72 miles of pipe containing vintage fabrication and construction threats interacting with high risk land movement.⁷¹² Our opening testimony and workpapers describe

⁷⁰⁹ PG&E-03, p. 5-67, line 26 to p. 5-69, line 21; PG&E-3-ES, WP 5-107; PG&E-03, WP 5S-17.

⁷¹⁰ PG&E-16-E, p. 5-65, lines 27-30; TURN-04, p. 38, line 1 to p. 45, line 18.

⁷¹¹ PG&E-03, p. 5-76, line 11 to p. 5-77, line 27; PG&E-16-E, p. 5-68, lines 20-24.

⁷¹² PG&E-03, p. 5-78, lines 13-16.

the Vintage Pipe Replacement program and provide evidence demonstrating that the program and PG&E’s cost forecast for the rate case period are prudent and reasonable.⁷¹³

Despite PHMSA’s encouragement to address these types of threats, situations where similar threats have resulted in pipeline ruptures, and industry best practices, TURN’s primary recommendation is to eliminate the Vintage Pipe Replacement Program, with an alternative recommendation to remove projects in areas that have an impacted occupancy count (IOC) less than 10 and to use TURN’s cost model:

TABLE 3-29
VINTAGE PIPE REPLACEMENT (MAT 75E): PG&E’S CAPITAL FORECAST AND PARTIES
RECOMMENDED REDUCTIONS (\$000s)^(a)

Party	2020 Rec.	2021	2022	2023	2024	2025	2026
PG&E	\$22,888	\$20,789	\$43,174	\$10,835	\$11,076	\$13,139	\$12,305
TURN (Primary) ^(b)				\$(10,835)			
TURN (Alternative)				\$(7,127)			
(a) PG&E-16-E, p. 5-91, Table 5-6, line 4 (PG&E’s 2020-2022 recorded and forecast costs); PG&E-3-ES, p. v (PG&E’s 2023-2026 forecast); PG&E-64, p. JCE 3-13 (TURN’s recommendation). (b) TURN recommends no funding for MAT 75E. TURN’s recommended reduction has been adjusted to equal PG&E’s forecast reflecting the corrected escalation errata. PG&E-64, p. JCE 3-13 (TURN’s recommendation).							

TURN’s primary proposal to eliminate the Vintage Pipe Replacement Program is based on the program’s RSE score and benefit-cost ratio.⁷¹⁴ TURN’s flawed RSE and benefit-cost analysis is addressed generally in Sections 2.3 and 3.2.2.1 of this opening brief. With regard to the Vintage Pipe Replacement Program specifically, TURN’s narrow focus on RSEs and benefit-cost ratios ignores the fact that there are significant threats of a pipeline rupture under certain

⁷¹³ PG&E-03, p. 5-72, line 1 to p. 5-75, line 7; p. 5-76, line 10 p. 5-80, line 5; PG&E-3-ES, WP 5-110 to WP 5-11; PG&E-03, WP 5-112.

⁷¹⁴ PG&E-16-E, p. 5-69, lines 6-7; TURN-02, p. 104, line 5 to p. 106, line 2; TURN-04, p. 52, line 22 to p. 54, line 3.

conditions that the program is intended to mitigate. TURN also ignores direction from PHMSA requiring operators to mitigate pipeline with a potential for failure.⁷¹⁵

PG&E's program is limited to less than a mile of pipeline and is designed to address the "highest potential rupture sites."⁷¹⁶ PG&E has a detailed methodology for identifying the highest risk pipelines that may rupture as a result of construction defects and land movement, a methodology which TURN does not dispute but simply ignored.⁷¹⁷ TURN candidly admits that it does not dispute the existence of construction defects in the pipelines that PG&E proposes to replace during the rate case period, nor does TURN dispute that these pipelines are located in areas considered at high risk for landslides.⁷¹⁸ Yet despite these admissions, TURN proposes that PG&E simply monitor these pipelines in case there is further deterioration rather than proactively addressing and mitigating the risk.⁷¹⁹ This kind of "delay needed work and cross your fingers hoping that an incident doesn't happen" approach is neither reasonable nor prudent. TURN's proposal should be rejected by the Commission.

Perhaps recognizing that its primary position compromises safety, TURN proposes as an alternative that PG&E only replace vintage pipes in areas where the impacted occupancy is 10 or greater. Even though the potential impacted occupancy of a rupture is an important factor to consider, it is not the only factor. A rupture can impact individuals in the immediate vicinity as well as the entire gas pipeline system. As a prudent operator, PG&E has an obligation to mitigate potential failures. TURN's proposal that PG&E mitigate some failures, but effectively ignore failures in areas with a lower impacted occupancy should not be adopted.⁷²⁰

⁷¹⁵ PG&E-16-E, p. 5-69, lines 15-22.

⁷¹⁶ PG&E-16-E, p. 5-69, line 22 to p. 5-70, line 3.

⁷¹⁷ PG&E-16-E, p. 5-70, lines 4-27.

⁷¹⁸ PG&E-46, TURN's response to Data Request PG&E_TURN027-Q05, dated 8/11/22.

⁷¹⁹ TURN-04, p. 55, lines 5-7.

⁷²⁰ PG&E-16-E, p. 5-71, lines 20-27.

Finally, TURN's alternative proposal also reduces the unit cost for pipeline replacement by removing the carryover costs from PG&E's replacement cost calculator.⁷²¹ The carryover costs included in PG&E's replacement cost calculator reflect project costs that often do not occur until after a project is operational (*i.e.*, costs to close out an operational project such as site remediation or paving over the replaced pipeline). PG&E used actual carry over cost data from 2016-2018 to estimate the carry over costs from projects completed in 2021 and 2022 that would then carry over into the rate case period. These costs from projects completed in 2021 and 2022 will be incurred during the rate case period and thus are entirely appropriate to recover.⁷²² TURN's proposal to prevent PG&E from recovering these costs should be rejected.

3.4.5 Shallow and Exposed Pipe (Including Water and Levee Crossings) – Capital (MATs 75M, 75T and 75K)

PG&E's Shallow and Exposed Pipe Program identifies locations where a pipeline has insufficient ground cover, is vulnerable to damage from third parties, or becomes exposed due to natural forces. Given the safety risks presented by exposed natural gas transmission pipelines, PG&E seeks to prioritize and mitigate these risks. The Shallow and Exposed Pipe Program also addresses risks at water and levee crossings.⁷²³ Our opening testimony and workpapers describe the Shallow and Exposed Pipe program and provide evidence demonstrating that the program and PG&E's cost forecast for the rate case period are prudent and reasonable.⁷²⁴

TURN proposes that this program be eliminated or, in the alternative, that the forecast be reduced by 30%:

⁷²¹ PG&E-16-E, p. 5-71, lines 28-29; TURN-04, p. 56, line 1 to p. 57, line 23.

⁷²² PG&E-16-E, p. 5-72, lines 1-18.

⁷²³ PG&E-16-E, p. 5-72, line 23 to p. 5-73, line 4.

⁷²⁴ PG&E-03, p. 5-119, line 1 to p. 5-127, line 30; p. 5-129, line 8 to p. 5-130, line 18; PG&E-3-ES, WP 5-120 to WP 5-121.

TABLE 3-30
SHALLOW AND EXPOSED PIPE (MAT 75M, 75T AND 75K): PG&E'S CAPITAL FORECAST
AND PARTIES RECOMMENDED REDUCTIONS (\$000s)^(a)

Party	2020 Rec.	2021	2022	2023	2024	2025	2026
PG&E	\$18,410	\$19,879	\$41,975	\$27,808	\$28,503	\$29,301	\$30,210
TURN (Primary) ^(b)				\$(27,808)			
TURN (Alternative)				\$(8,342)			
(a) PG&E-16-E, p. 5-91, Table 5-6, lines 8, 10 and 17 (PG&E's 2020-2022 recorded and forecast costs); PG&E-3-ES, p. v (PG&E's 2023-2026 forecast); PG&E-64, p. JCE 3-14 (TURN's recommendation). (b) TURN recommends no funding for MATs 75M, 75T and 75K. TURN's recommended reduction has been adjusted to equal PG&E's forecast reflecting the corrected escalation errata. PG&E-64, p. JCE 3-14 (TURN's recommendation).							

TURN asserts that the RSE score and benefit-cost ratio for the Shallow and Exposed Pipe Program justifies its elimination.⁷²⁵ However, TURN ignores the multiple, high-risk conditions along PG&E's pipeline system caused by shallow and exposed pipelines or pipelines at water/levee crossings. As PG&E explained in rebuttal testimony, these conditions result in a high likelihood of failure if not mitigated.⁷²⁶ In addition, TURN ignores the fact that PG&E has used a site-specific methodology to determine the greatest risk sites, which PG&E is proposing to mitigate during the rate case period.⁷²⁷ TURN's narrow focus on RSE scores fails to consider the real world conditions and risks identified by PG&E related to shallow and exposed pipe, as well as pipes at levee and water crossings.

In addition, TURN's proposal to eliminate the Shallow and Exposed Pipe Program ignores regulatory guidance from PHMSA and the California State Lands Commission. In its rebuttal testimony, PG&E explained why TURN's proposal is contrary to clear regulatory direction.⁷²⁸

⁷²⁵ PG&E-16-E, p. 5-73, lines 13-19; TURN-02, p. 108, lines 6-7.

⁷²⁶ PG&E-16-E, p. 5-73, line 23 to p. 5-74, line 12.

⁷²⁷ PG&E-16-E, p. 5-74, lines 13-27.

⁷²⁸ PG&E-16-E, p. 5-75, lines 5-23.

TURN's alternative proposal for a 30% haircut to PG&E's forecast is equally unfounded. TURN argues that PG&E's recorded costs for 2016 to 2020 were lower than PG&E's forecast in this proceeding.⁷²⁹ However, this is because PG&E spent funds on higher risk mitigations and controls during this time period. In fact, during this time period, PG&E spent 33% more than its adopted forecasts for the 2016-2020 time period on these higher risk programs and the Shallow and Exposed Pipe Program.⁷³⁰ TURN fails to provide any evidence to justify a 30% reduction now that much of the higher risk work identified earlier has been completed.

3.4.6 Public Awareness (MAT JT0)

Federal regulations require PG&E to develop and implement public education programs that comply with the American Petroleum Institute's recommended practices.⁷³¹ In compliance with these regulations, PG&E has developed a public awareness program with three objectives: (1) increase awareness about the presence of natural gas pipelines; (2) reduce third-party damage to pipelines through education outreach; and (3) promote emergency response readiness. Our opening testimony and workpapers describe the Public Awareness program and provide evidence demonstrating that the program and PG&E's cost forecast for the rate case period are prudent and reasonable.⁷³² TURN was the only party that disputed PG&E's forecast for the public awareness program:

⁷²⁹ TURN-05, pp. 5-6.

⁷³⁰ PG&E-16-E, p. 5-76, lines 4-11; p. 5-77, Table 5-4.

⁷³¹ PG&E-16-E, p. 5-66, lines 6-24.

⁷³² PG&E-03, 5-99, line 20 to p. 5-103, line 8; p. 5-106, line 22 to p. 5-107, line 16; PG&E-3-E, WP 5-46.

TABLE 3-31
PUBLIC AWARENESS (MAT JT0): PG&E'S EXPENSE FORECAST AND PARTIES
RECOMMENDED REDUCTIONS (\$000s)^(a)

Party	2020 Rec.	2021	2022	2023
PG&E	\$2,430	\$2,004	\$2,366	\$4,386
TURN				\$(1,45)
(a) PG&E-16-E, p. 5-89, Table 5-5, line 20 (PG&E's 2020-2022 recorded and forecast costs); PG&E-3-ES, p. iii (PG&E's 2023 forecast); PG&E-64, p. JCE 3-25 (TURN's recommendation).				

TURN bases its recommended reduction on PG&E's historical spending between 2016-2020, arguing that PG&E underspent the program in prior years and thus PG&E's current forecasts are too high. TURN also asserts that ratepayers have already provided funding in previous years that should have been used for this program.⁷³³

While we do not dispute that underspending has occurred in the past, PG&E addressed this underspending by using a three-year average of historical spend to develop its forecast. PG&E also included additional amounts in its forecast to account for a new Global Positioning System (GPS) program that will start in 2023. The GPS Program uses real time data and motion sensors placed on excavation equipment to monitor the excavator's location and activities. The GPS program includes an automated alert system that notifies utility personnel and the excavator if there is a risk of a natural gas pipeline dig-in.⁷³⁴ The GPS program has the potential to significantly reduce construction site dig-ins. TURN's forecast did not consider the new GPS program.⁷³⁵ Because PG&E addressed past underspending by using a historical three-year average and TURN failed to consider costs associated with the new GPS Program, TURN's proposed reduction should be rejected.

⁷³³ PG&E-16-E, p. 5-67, lines 1-7; TURN-05, p. 4.

⁷³⁴ PG&E-16-E, p. 5-67, lines 8-25; p. 5-68, lines 6-17.

⁷³⁵ PG&E-16-E, p. 5-67, line 26 to p. 5-68, line 3.

3.4.7 TIMP Balancing and Memorandum Accounts

The TIMP Balancing Account or “TIMPBA” is a one-way balancing account that the Commission established in the 2019 GT&S rate case to track TIMP related costs.⁷³⁶ The TIMP Memorandum Account or “TIMPMA” was established in the 2015 GT&S rate case and is used to track any TIMP costs that are not included in PG&E’s forecast “associated with any new transmission integrity management statutes or rules, or new or changed interpretation by a regulatory body of transmission or integrity management statutes or rules.”⁷³⁷

In this proceeding, PG&E is proposing to convert the TIMPBA to a two-way balancing account and to eliminate the TIMPMA. Alternatively, if the TIMPBA remains a one-way balancing account, PG&E is proposing to keep the TIMPMA and modify it so that it tracks all costs above adopted amounts related to existing TIMP regulations as well as costs associated with new TIMP regulations.⁷³⁸ PG&E is proposing to structure the two-way TIMPBA so that all costs above or below the authorized amount would be trued up annually through a Tier 2 advice letter process. However, for costs greater than 135 percent of the adopted amount, PG&E would record these costs in a separate subaccount and would file a separate application for recovery of these costs.⁷³⁹ Eliminating the TIMPMA and converting the TIMPBA into a two-way balancing account would reduce the current administrative complexity involved in maintaining a balancing account and a memorandum account and the necessary reviews that are required.⁷⁴⁰

TURN and Cal Advocates oppose PG&E’s TIMPBA and TIMPMA proposals. With regard to PG&E’s primary proposal to convert the TIMPBA into a two-way balancing account

⁷³⁶ PG&E-16-E, p. 5-78, line 27 to p. 5-79, line 2; D.19-09-025, p. 159 (establishing TIMPBA).

⁷³⁷ PG&E-16-E, p. 5-79, lines 3-10, quoting PG&E’s Gas Preliminary Statement, Part DP, Section 1 (establishing and describing the TIMPMA).

⁷³⁸ PG&E-16-E, p. 5-79, lines 11-20.

⁷³⁹ PG&E-03, p. 5-18, lines 7-25; PG&E-16-E, p. 5-81, lines 25-29.

⁷⁴⁰ PG&E-03, p. 5-17, line 23 to p. 5-18, line 2.

and eliminate the TIMPMA, TURN and Cal Advocates both argue that the Commission rejected similar requests in the 2015 and 2019 GT&S rate cases.⁷⁴¹ While it is true that the Commission previously concluded that a one-way balancing account for the TIMPBA was appropriate, circumstances have changed since these rate cases were decided and thus the Commission should re-examine its earlier approach. Specifically, PMSHA is continuing to issue new regulations which will likely increase TIMP costs during the 2023 GRC period (2023-2026) and thus there is substantial uncertainty regarding TIMP costs.⁷⁴² To address this uncertainty, a two-way balancing account is appropriate. In addition to PHMSA regulations, the Commission has recently adopted two-way balancing accounts in the face of significant cost uncertainty for other programs.⁷⁴³ These recent Commission decisions support PG&E's request for a two-way balancing account.

In addition to these recent developments supporting a two-way balancing account, approving a two-way TIMPBA in this proceeding would be consistent with the Commission's treatment of other gas utilities that have two-way balancing accounts for TIMP-related costs.⁷⁴⁴ TURN's opposition to converting the TIMPBA into a two-way balancing account is particularly surprising because TURN has supported a two-way TIMP balancing account for SDG&E. As the Commission explained in its decision approving an earlier SDG&E settlement:

As part of the Attachment 5 Settlement Agreement of the Applicants' Settlement Motions, TURN, UCAN, and the Applicants agreed that each utility will continue to maintain separate two-way balancing accounts for the TIMP and DIMP expenditures, and agreed on the process for recovery of undercollected amounts.

None of the parties have objected to these provisions regarding the TIMP and DIMP.

⁷⁴¹ TURN-04, p. 3, line 4 to p. 5, line 9; CALPA-02, p. 36, line 14 to p. 37, line 9.

⁷⁴² PG&E-03, p. 5-16, lines 3-22; PG&E-16-E, p. 5-80, lines 4-12.

⁷⁴³ PG&E-03, p. 5-17, lines 3-11.

⁷⁴⁴ PG&E-03, p. 5-17, lines 12-22.

Since the TIMP and DIMP costs may vary, depending on federal regulatory action, it is reasonable to continue the two-way balancing account treatment for the TIMP and DIMP costs, and to establish a procedure to recover the undercollected amounts. This portion of the Attachment 5 Settlement Agreement should be adopted.⁷⁴⁵

In addition to relying on the 2015 and 2019 GT&S decisions, TURN also argues that a two-way balancing account is unnecessary because PG&E can recover TIMP costs above the adopted amount through the TIMPMA.⁷⁴⁶ However, TURN’s testimony on this point is internally inconsistent. On the one hand, TURN is saying that PG&E can recover costs above GRC adopted amounts through the TIMPMA. But earlier in its testimony, TURN argues that TIMPMA is limited to costs associated only with regulatory changes and that the Commission should “deny PG&E’s attempts to include cost overruns under existing regulations in the TIMPMA”⁷⁴⁷ Under the current TIMPBA and TIMPMA structure, PG&E is limited in its ability to recover higher costs resulting from existing regulations which create cost uncertainty. As explained above, the TIMPMA is only authorized by D.19-09-025 to address incremental costs associated with any “new transmission integrity management statutes or rules” and does not currently allow for the tracking of all TIMP expenses above adopted amounts. The TIMPBA should be converted to a two-way balancing account to address this issue.

TURN argues that under its proposal, PG&E could file advice letters “at any time with minimal notice...”⁷⁴⁸ However, PG&E indicated that under its proposal it would file the TIMPBA advice letter annually through a publicly noticed and well-established advice letter process. TURN is certainly aware of advice letter filings and frequently protests advice letters that TURN believes are not appropriate. Thus, TURN and other parties will have notice of and

⁷⁴⁵ D.16-06-054, pp. 108-109.

⁷⁴⁶ TURN-04, p. 5, lines 1-2.

⁷⁴⁷ TURN-04, p. 2, line 24 to p. 3, line 1; see also TURN-04, p. 2, lines 14-18 (TIMPMA “provides significant protections for ratepayers” by limiting the costs PG&E can recover).

⁷⁴⁸ TURN-04, p. 2, lines 9-11.

the ability to protest PG&E's advice letter filing. In addition, filing annually will mean that customers receive any over-collection in a timely and consistent manner.⁷⁴⁹

If PG&E's proposal to convert the TIMPBA to a two-way balancing account is not adopted, the Commission should approve PG&E's alternative proposal to expand the TIMPMA to include TIMP costs above the adopted amounts. Compliance with TIMP regulations is mandatory and given that these regulations change and there is uncertainty regarding costs, at a minimum PG&E should be able to recover all TIMP related costs through the TIMPMA, rather than just costs associated with new regulations.⁷⁵⁰ Notably, with regard to PG&E's proposed alternative, TURN is unclear on its position. TURN argues that TIMPMA should not be used for cost overruns, but then describes TIMPMA as allowing PG&E to "recover its reasonable TIMP costs incurred beyond the authorized levels in the GRC..."⁷⁵¹ There is no reason to limit the TIMPMA only to new regulations and interpretations, a point that even TURN appears to concede.

3.4.8 ILI Balancing and Memorandum Accounts

The ILIBA and ILIMA were established by the Commission in the 2019 GT&S rate case.⁷⁵² The ILIBA records capital costs for the 48 Traditional ILI Upgrade projects adopted for the rate case period. The ILIMA records capital costs incurred for projects completed above the 48 adopted ILI upgrades, the associated initial assessments and DE&R expenses, as well as all reassessment expenses and associated repairs.⁷⁵³ These accounts were adopted in the 2019 GT&S Rate Case primarily to address concerns that PG&E would not be able to complete more the 18 ILI Upgrade projects per year that it was forecasting. Thus, the Commission set the

⁷⁴⁹ PG&E-16-E, p. 5-82, lines 2-10.

⁷⁵⁰ PG&E-03, p. 5-19, line 29 to p. 5-20, line 2.

⁷⁵¹ TURN-04, p. 5, lines 1-2.

⁷⁵² D.19-09-025, pp. 330-331, OP 57, 63.

⁷⁵³ PG&E-03, p. 5-36, line 29 to p. 5-37, line 13.

authorized number of ILI Upgrades at 12 but provided PG&E to opportunity to do more and record these costs in the ILIMA.⁷⁵⁴ In this case, however, PG&E is proposing to perform 12 ILI Upgrades per year, consistent with the Commission’s direction, thus there is no need for the ILIBA and ILIMA structure adopted in the 2019 GT&S Rate Case. Because they are no longer needed, PG&E is proposing to eliminate the ILIBA and ILIMA. Costs associated with initial runs, re-assessments and any associated repairs would be accounted for in the TIMPBA because these costs relate to a TIMP program.⁷⁵⁵

Cal Advocates opposes eliminating these accounts arguing that they protect customers by returning underspent amounts, allow the Commission to review PG&E’s costs for reasonableness, and allow the Commission to track costs in excess of the authorized amount.⁷⁵⁶ However, this is exactly what the parties are doing in this proceeding. PG&E has put forward a proposal for ILI Upgrades and assessments during the 2023 GRC period (2023-2026) and parties, including Cal Advocates, have been actively scrutinizing that proposal. If Cal Advocates believes PG&E will underspend its proposed amount, the place to address that issue is in this proceeding, not through a balancing account. Moreover, the reasonableness of the costs is being evaluated in this proceeding. There is no need for a redundant review process through the ILIBA and ILIMA when PG&E’s forecasts can be and are being reviewed in this proceeding.

TURN also supports retaining the ILIBA and ILIMA. However, TURN offers scant reasoning for its proposal to continue the ILIBA and ILIMA other than citing the Commission’s decision from the 2019 GT&S Rate Case and asserting that these accounts provide “performance incentives” for PG&E.⁷⁵⁷ Given that the entire reason for the ILIBA and ILIMA structure no longer exists (i.e., PG&E is no longer proposing to do 18 ILI Upgrades per year), there is no

⁷⁵⁴ PG&E-03, p. 5-36, line 29 to p. 5-37, line 13.

⁷⁵⁵ PG&E-16-E, p. 5-83, line 26 to p. 5-84, line 11.

⁷⁵⁶ CALPA-02, p. 37, lines 12-17.

⁷⁵⁷ TURN-04, p. 6, lines 2-3.

need to continue these accounts. Moreover, after stating that the ILIBA and ILIMA should be retained,⁷⁵⁸ TURN later states that the ILIBA should be retained but the ILIMA should be eliminated because no additional ILI Upgrades should be performed other than the four per year recommended by TURN.⁷⁵⁹ PG&E agrees with TURN that the ILIMA should be eliminated, but strongly opposes TURN's proposal to limit the number of ILI Upgrades to four per year.

TURN does, however, support one aspect of PG&E's proposal. TURN appears to support including reassessment costs and associated repairs in the TIMPBA.⁷⁶⁰ PG&E agrees with this aspect of TURN's testimony but believes that PG&E's proposal should be adopted in its entirety.

Finally, TURN proposes that ILI Upgrade capital costs be recorded to the ILIBA and that these costs "be subject to scrutiny and demonstrated to be cost effective before it is completed. PG&E's proof should involve project specific examination of the RSEs and benefit cost ratios associated with individual transmission pipeline that PG&E proposes to upgrade."⁷⁶¹ TURN's proposal for the ILIBA is, at best, unclear. While balancing and memorandum accounts are typically used to record and track costs and, in some cases, allow for review of the costs after they have been incurred, TURN seems to be suggesting that through the ILIBA the Commission review every ILI Upgrade "before it is completed" for cost effectiveness. TURN proposes using its RSE and benefit-cost approach. TURN fails to offer any specifics regarding its proposal such as when this review would occur with regard to project development, how to address the delays caused by requiring regulatory approval of each ILI Upgrade project, and how the Commission should define cost-effectiveness. TURN's proposal would effectively require the Commission to review and approve every ILI Upgrade project before any work commences. This would be

⁷⁵⁸ TURN-04, p. 6, lines 2-3.

⁷⁵⁹ TURN-04, p. 22, lines 3-5.

⁷⁶⁰ TURN-04, p. 5, lines 13-19.

⁷⁶¹ TURN-04, p. 12, lines 14-17.

burdensome for the Commission and parties and would delay safety and reliability upgrades. In short, TURN's incomplete proposal should be rejected.

3.4.9 ICDA Memorandum Account

The ICDAMA was adopted by the Commission in the 2019 GT&S Rate Case to track recorded ICDA expenses for the 2019-2022 rate case period.⁷⁶² The ICDAMA was adopted in the 2019 GT&S Rate Case primarily to address concerns that PG&E had not completed ICDA work in the 2015 GT&S rate case period in order to instead fund more TIMP strength tests. Thus, the Commission established this memorandum account to track ICDA work for 2019 GT&S rate case period (2019-2022).⁷⁶³ However, PG&E has completed the units of ICDA work authorized in the 2019 GT&S Rate Case, thus eliminating the need for the ICDAMA. Since the basis for establishing and maintaining this memorandum account no longer exists and is no longer applicable, PG&E proposes to eliminate the ICDAMA and allow the ICDA recorded costs to flow through the TIMPBA as intended given they are Subpart O TIMP related expenses.⁷⁶⁴

The only party that opposes this proposal is Cal Advocates based on its assertion that the ICDAMA allows for the tracking of costs and reasonableness review which “protects ratepayers should PG&E underperform in the Test Year.”⁷⁶⁵ However, as explained above, the purpose of the ICDAMA is no longer applicable because PG&E completed the ICDA units authorized in the 2019 GT&S rate case. Moreover, as explained above in Section 3.4.2.4 regarding ICDA, PG&E's forecasts for ICDA for this rate case period (2023-2026) are reasonable and thus there is no reason for additional review by the Commission other than the thorough review that is

⁷⁶² D.19-09-025, pp. 143, 145, and 331 (OP 64).

⁷⁶³ PG&E-03, p. 5-50, lines 1-15.

⁷⁶⁴ PG&E-16-E, p. 5-87, lines 3-12.

⁷⁶⁵ CALPA-02, p. 30, lines 14-17.

occurring in this proceeding. Finally, a second review is unnecessary and would only result in the Commission and parties spending additional time and resources.

3.5 Asset Family – Facilities

This chapter addresses the Compression and Processing (C&P), Measurement and Control (M&C) Stations and Compressed Natural Gas (CNG) asset families (together referred to as “Facilities”). These gas transmission and distribution (GT&D) assets include compression and processing facilities as part of the C&P asset family, gas regulation stations as part of the M&C asset family, and CNG stations as part of the Liquefied Natural Gas/ Compressed Natural Gas (LNG/CNG) asset family.⁷⁶⁶

PG&E’s Corrected Forecast for GD expense is \$6.223 million.⁷⁶⁷ PG&E’s JCE forecast for GD expense is \$6.692 million.⁷⁶⁸

PG&E’s Corrected Forecast for GT&S expense is \$27.446 million.⁷⁶⁹ PG&E’s JCE forecast for GT expense is \$30.841 million.⁷⁷⁰

PG&E’s Corrected Forecast for GD capital is \$145.434 million in 2021, \$152.818 million in 2022, \$101.066 million in 2023, \$98.576 million in 2024, \$100.844 million in 2025, and \$87.413 million in 2026⁷⁷¹ PG&E’s JCE forecast for GD capital is \$152.868 million in 2021,

⁷⁶⁶ PG&E-03, p. 6-1, lines 6-16.

⁷⁶⁷ PG&E-16-E, p. 6-4, Table 6-1, line 3.

⁷⁶⁸ PG&E-64, p. 3-1, Table 3A-1, lines 6-7.

⁷⁶⁹ PG&E-3-ES, p. iii, which reflects PG&E’s rebuttal forecast updated with corrected escalation factors.

⁷⁷⁰ PG&E-64, p. 3-1, Table 3A-1, lines 8-9.

⁷⁷¹ PG&E-16-E, p. 6-42, Table 6-9, line 6 (2021 and 2022) and PG&E-3-ES, p. v, which reflects PG&E’s rebuttal forecast updated with corrected escalation factors. (2023-2026).

\$169,092 million in 2022, \$113.203 million in 2023, \$107.516 million in 2024, \$107.423 million in 2025, and \$90.875 million in 2026.⁷⁷²

PG&E's Corrected Forecast for GT&S capital is \$170.867 million in 2021, \$83.040 million in 2022, \$245.286 million in 2023, \$244.459 million in 2024, \$243.281 million in 2025, and \$244.604 million in 2026.⁷⁷³ PG&E's JCE forecast for GT&S capital is \$209.351 million in 2021, \$112.933 million in 2022, \$309.888 million in 2023, \$276.928 million in 2024, \$262.023 million in 2025, and \$256.255 million in 2026.⁷⁷⁴

Of the 9 expense GD and GT&S expense MATs related to Facilities, only 3 are disputed. Similarly, for the 17 GD and GT&S capital MATs, only 5 are disputed. The undisputed programs, associated MATs, and corresponding expense and capital forecasts are identified in Appendix A. In the remainder of this Section 3.5, we address the following disputed programs.

**TABLE 3-32
SUMMARY OF ISSUES ADDRESSED IN SECTION 3.5**

Section	Disputed Program	Impacted MATs
3.5.1	GT Routine C&P Program	Expense (MAT JTY)
3.5.2	GT M&C Terminal Upgrades	Capital (MAT 765)
3.5.3	GT and GD M&C Station OPP Enhancements Program	Expense and Capital (MATs FHQ, JTX, 50N and 76G)
3.5.4	HPR Program	Capital (MWC 2K)
3.5.5	GT C&P Compressor Replacements and Retirements: Los Medanos Compressor Replacement	Capital (MAT 76X)
3.5.6	GT C&P Compressor Replacements and Retirements: Tionesta Compressor Station Retirement	Capital (MAT 76X)

⁷⁷² PG&E-64, p. 3-6, Table 3B-1, lines 7-9 (2023); p. 3-10, Table 3B-2, lines 7-9 (2022); and p. 3-14, Table 3B-3, lines 7-9 (2021). Forecasts for 2024-2026 are not included in the JCE but are provided here for reference.

⁷⁷³ PG&E-16-E, p. 6-43, Table 6-10, line 17 (2021 and 2022) and PG&E-3-ES, p. v, which reflects PG&E's rebuttal forecast updated with corrected escalation factors. (2023-2026).

⁷⁷⁴ PG&E-64, p. 3-6, Table 3B-1, lines 10-11 (2023); p. 3-10, Table 3B-2, lines 10-11 (2022); and p. 3-14, Table 3B-3, lines 10-11 (2021). Forecasts for 2024-2026 are not included in the JCE but are provided here for reference.

3.5.1 GT Routine C&P Program – Expense (MAT JTY)

The GT Routine C&P Expense Program (MAT JTY) includes projects that arise during normal operation of C&P facilities that must be performed to maintain current levels of service and reliability. Typical projects include repair or replacement of failed or malfunctioning equipment and instrumentation, compressor unit overhauls, inspection and testing of asset components, and modifications to address equipment safety or performance issues.⁷⁷⁵ TURN is the only party that addresses this program and proposes:

TABLE 3-33
GT ROUTINE C&P PROGRAM (MAT JTY): PG&E’S EXPENSE FORECAST AND PARTIES
RECOMMENDED REDUCTIONS (\$000s)^(a)

Party	2020 Rec.	2021	2022	2023
PG&E	\$7,821	\$10,000	\$9,814	\$10,013
TURN				\$(1,496)

(a) PG&E-16-E, p. 6-41, Table 6-8, line 6 (2020-2022 recorded and forecast amounts); PG&E-3-ES, p. iii (2023 forecast); PG&E-64, p. JCE 3-48 (TURN’s recommendation).

TURN disagrees with PG&E’s forecasting methodology for this program, which is based on a historical 3-year average (2018-2020), escalated to 2023. TURN argues that the recorded costs declined over the last three years and thus 2020 costs should be used.⁷⁷⁶ However, TURN’s recommendation reflects a forecasting method that maximizes reductions for the program based on selecting the single lowest recorded cost year. The Routine C&P program has expense and capital⁷⁷⁷ components and for all Asset Family – Facilities non-unitized programs that use the recorded costs as a forecast basis, PG&E used a 3-year average (2018-2020) because it is a more accurate representation of the spending pattern expected for the 2023 GRC period. TURN’s recommendation would result in using inconsistent forecast approaches for the same

⁷⁷⁵ PG&E-03, p. 6-18, line 12 to p. 6-19, line 21.

⁷⁷⁶ TURN-05, p. 7.

⁷⁷⁷ No party made recommendations on PG&E’s Routine C&P Capital Program (MAT 76N).

program, one method for routine C&P expense (most recent recorded year 2020) and another method for routine C&P capital (adopting PG&E's methodology of a 3-year average).

Depending on the type of repair, replacement projects and the facility where work is performed, there is some variation in costs expected year over year for the program. In addition, 2020 is not a representative year that should be relied upon for this program due to COVID-19 related delays from pausing non-essential work.⁷⁷⁸ PG&E's use of an historical average for forecasting programmatic work accounts for year-over-year fluctuations and provides a predictable trend of the expected future level of work as opposed to relying on a single year as TURN recommends.⁷⁷⁹

3.5.2 GT M&C Terminal Upgrades – Capital (MAT 765)

The GT M&C Terminal Upgrades Program (MAT 765) includes upgrades and rebuilds to address equipment aging and obsolescence for the three gas terminals at Milpitas, Antioch, and Brentwood. The GT M&C Terminal Upgrades Program includes two types of work: (1) routine terminal upgrades at all three terminal stations that includes regular upgrades and maintenance to maintain reliability of the GT system, and (2) a phased approach for rebuilding the Brentwood Terminal.⁷⁸⁰ TURN is the only party that addresses this program and proposes:

⁷⁷⁸ PG&E-03, p. 2-18, line 13 to p. 2-19, line 18.

⁷⁷⁹ PG&E-16-E p. 6-10, lines 11-29.

⁷⁸⁰ PG&E-03, p. 6-46, line 28 to p. 6-48, line 11.

TABLE 3-34
GT M&C TERMINAL UPGRADES (MAT 765): PG&E’S CAPITAL FORECAST AND PARTIES
RECOMMENDED REDUCTIONS (\$000s)^(a)

Party	2020 Rec.	2021	2022	2023	2024	2025	2026
PG&E	\$3,114	\$10,927	\$7,273	\$16,920	\$17,343	\$17,454	\$17,574
TURN				\$(14,569)	\$(14,949)	\$(14,949)	\$(14,938)
(a) PG&E-16-E, p. 6-43, Table 6-10, line 4 (2020-2022 recorded and forecast amounts); PG&E-3-ES, p. v (2023-2026 forecasts); PG&E-64, p. JCE 3-44 (TURN’s recommendations).							

TURN did not make any recommendations related to the Routine Terminal Upgrades work forecast under this program but recommends the removal of all costs for the Brentwood Terminal Rebuild project, which represents a reduction of \$14.6 million annually or a total decrease of \$58.3 million (un-escalated forecast) for the years 2023-2026.⁷⁸¹ TURN objects to the inclusion of these expenditures arguing that PG&E “has not demonstrated that this terminal will be used and useful and has severely underspent for the Brentwood Terminal Rebuild to-date (and thus been overcompensated).”⁷⁸² TURN’s arguments are addressed below.

3.5.2.1 The Brentwood Terminal rebuild Will be Used and Useful During the 2023 GRC Period

PG&E does not agree with TURN’s assertion that the terminal will not be fully “used and useful” during the 2023 GRC Period (2023-2026).⁷⁸³ The individual phases of construction at the Brentwood Terminal completed during this 2023 GRC period will become operational (used and useful) and will provide service to customers. Moreover, the existing Brentwood Terminal will continue to remain in operation during the phased rebuild process forecast during the 2023 GRC period.

⁷⁸¹ TURN-05, p. 9. PG&E is reflecting TURN’s adjustment to eliminate funding for this project completely, including escalation as reflected in PG&E-03-ES, WP 6-46, line 3 (\$59.4 million in 2023-2026). This is reflected in PG&E-16-E, p. 6-6, Table 6-4.

⁷⁸² TURN-05, p. 9.

⁷⁸³ TURN-05, p. 8.

The overall Brentwood Terminal rebuild is broken into multiple phases in order to minimize impact on the operation of the system and to minimize any impacts to customers.⁷⁸⁴ Since Brentwood Terminal serves as a junction for several major gas pipelines in the East Bay Area, construction must be phased in order to limit impact on the surrounding system. The system outages required to remove existing equipment and install new equipment must be relatively short in duration and impact only one or two of the connected pipelines. Removing the entire station from service to complete the rebuild is not an option.⁷⁸⁵

The phasing approach divides the scope of work into segments (sub-components of work tasks) which could be easily bundled into construction plans/sequence while minimizing safety, economic, maintenance or operational impacts.⁷⁸⁶ Phased construction is scoped and sequenced so that one phase is completed before starting construction on the subsequent phase. This sequence is performed to allow the facility to remain in service, but to also limit the burden of overhead and indirect costs which occur on long duration projects.⁷⁸⁷

Based on this, PG&E's forecast made a reasonable assumption that the total project capital spending forecast be allocated equally over four years (2023-2026) for purposes of modeling the operative date; this reflects the expectation that the phases will occur in sequence and be complete by the end of the 2023 GRC period.⁷⁸⁸

⁷⁸⁴ Phases 0 and 1 prepare the site and construct the ring header ahead of Phases 2 and 3. Phase 2 ties in the ring header to Line 57-B and Line 2. After this phase, the ring header and Line 57B and Line 2 are placed in service. Phase 3 ties in the ring header to Line 57A. After Phase 3, Line 57A and the ring header are placed in service and are "used and useful." During these construction phases, specific clearances allow for cut in of these lines to the ring header, but the entire Brentwood facility will continue to stay in operation. The final construction and clearance schedule for these phases will be defined after the detailed engineering is complete. PG&E-03, p. 6-49, line 4 to p. 6-50 line 10; and PG&E-16-E, p. 6-13, line 3 to p. 6-14, line 7.

⁷⁸⁵ PG&E-03, p. 6-48, lines 24-29.

⁷⁸⁶ PG&E-03, p. 6-48, lines 29-33.

⁷⁸⁷ PG&E-16-E, p. 6-13, lines 24-28.

⁷⁸⁸ PG&E-3-ES, WP 6-46.

3.5.2.2 PG&E Did Not Underspend On The Brentwood Terminal

TURN's claim that PG&E underspent on the Brentwood Terminal in the prior rate case period is without merit. First, for MAT 765, that includes the Brentwood facility, PG&E will be overspent, not underspent, for the entire 2019 GT&S rate case period. The 2019-2022 recorded and forecast cost for MAT 765 is \$30.35 million compared to \$26.88 million adopted⁷⁸⁹ for the same period, resulting in an overspend of \$3.46 million. The 2019-2022 recorded and forecast cost for the Brentwood Terminal Rebuild project portion of MAT 765 is \$12.04 million.⁷⁹⁰

Second, TURN's claim of underspending focusses on the 2019 and 2020 recorded costs for the terminal upgrade (about \$1.7 million) which was lower than the annual spending forecast by PG&E for those two years in the 2019 GT&S case. It is not uncommon, however, for large capital project execution to differ from the expected annual estimates developed years prior as new information emerges and as site and work conditions change. In addition, the Brentwood Terminal Rebuild project also experienced delays in 2020 due to overall COVID-19 related delays and work requirements.⁷⁹¹

Finally, PG&E ramped up the work the Brentwood Terminal Rebuild project in 2021 to complete the 2019 GT&S forecast scope of work by 2022.⁷⁹² PG&E recorded spending in 2021 of \$4.4 million and the forecast for 2022 is \$5.9 million, resulting in \$12.04 million of spend on this project over the last rate period.⁷⁹³

3.5.2.3 There are significant operational and safety risks if the Brentwood Terminal Rebuild does not receive funding

TURN's recommendation to disallow the entire Brentwood Terminal Rebuild forecast for the 2023 GRC period does not address any risks associated with not funding and rebuilding the

⁷⁸⁹ PG&E-03, WP 6-105, line 7.

⁷⁹⁰ PG&E-16-E, p. 6-15, Table 6-8.

⁷⁹¹ PG&E-03, p. 2-18, line 13 to p. 2-19, line 18.

⁷⁹² PG&E-16-E, p. 6-15, lines 8-21.

⁷⁹³ PG&E-16-E, p. 6-16, Table 6-8.

Brentwood Terminal. The Brentwood Terminal is one of the most critical pressure control facilities along PG&E’s gas transmission lines. The complexity of the facility, as well as equipment obsolescence and age, play a crucial role in the reliability of this terminal. The major risks associated with the Brentwood Terminal are:

- Age and Obsolescence Risk: The facility is over 70 years old and was built over many years as pipelines were added to the facility. The Brentwood Terminal has never had a comprehensive rebuild to simplify the configuration. There is obsolete equipment in the various regulation systems that requires replacement.
- Operational Risk: The facility has 12 independent MAOPs in the station. Since the facility was built and modified in stages over time, maintenance and operations activities of the station are overly complex.
- Safety Risk: The complexity of the station creates an increased risk to the public and workers relative to other PG&E gas facilities. The facility is in a highly populated area and currently shares a fence-line with multiple single-family homes.⁷⁹⁴

Based on these factors, the Brentwood Terminal has been identified for rebuild to mitigate current and future risks. The rebuild project as planned will significantly improve the reliability of this terminal.⁷⁹⁵ For these reasons the Commission should approve PG&E’s funding request so that PG&E can proceed to rebuild this critical facility.

3.5.3 GT and GD M&C Station OPP Enhancements Program – Expense and Capital (MATs FHQ, JTX, 50N and 76G)

The GT and GD M&C Station Overpressure Protection (OPP) Enhancements is a mitigation program to prevent large overpressure (OP) events due to equipment-related failure at regulator stations. Pilot-operated regulator stations, when compared to other M&C station types, are subject to a higher likelihood of OP events than other station designs. This is primarily because both the regulator and monitor (the primary OPP device) installed in many of these stations can fail in the “open” position—known as the “common mode failure”—when affected

⁷⁹⁴ PG&E-16-E, p. 6-16, line 26 to p. 6-17, line 13.

⁷⁹⁵ PG&E-16-E, p. 6-17, lines 14-16.

by contaminants in the system (sulfur, liquids, and other debris). PG&E's M&C Station OPP program initiatives address common mode failure at both GT and GD station assets.

The GT and GD M&C Station OPP Enhancements Expense Program (MATs FHQ and JTX) includes installing pilot filters to reduce the likelihood of pilot-operated regulator or monitor failure due to sulfur; and performing system planning studies, pilot studies, and program management. The GD M&C Station OPP expense scope also includes evaluating and testing modifications to the existing regulation devices on the low pressure (LP) regulator stations to isolate the station during both over- and under-pressure scenarios.⁷⁹⁶

The GT and GD M&C Station OPP Enhancements Capital Program (MATs 50N and 76G) includes activities for retrofitting pilot-operated type stations with slam-shuts (valves that automatically shut off gas if pressure rises above a certain threshold) or, if required, alternate technologies and relief valves. The GT M&C Station OPP capital program scope also includes rebuilding Large Volume Customer Meter (LVCM) facilities that are inconsistent with current design standards and operating conditions.⁷⁹⁷ TURN is the only party that addresses this program and proposes to completely eliminate all expense and capital funding for both GD and GT:

⁷⁹⁶ PG&E-16-E, p. 6-18, lines 10-17.

⁷⁹⁷ PG&E-03, p. 6-60, line 4 to p. 6-69, line 13; PG&E-16-E, p. 6-17 line 30 to p. 6-18 line 24.

TABLE 3-35
GD AND GT M&C STATION OPP ENHANCEMENTS PROGRAM (MATS FHQ, JTX, 50N AND 76G): PG&E'S CAPITAL FORECAST AND PARTIES RECOMMENDED REDUCTIONS (\$000s)

Party	2020 Rec.	2021	2022	2023	2024	2025	2026
PG&E ^(a)							
GD Expense (FHQ)	\$781	\$3,250	\$3,529	\$1,807			
GT Expense (JTX)	\$588	\$1,853	\$1,673	\$1,073			
Total Expense	\$1,369	\$5,103	\$5,202	\$2,880			
GD Capital (50N)	\$11,449	\$18,053	\$18,577	\$19,576	\$15,049	\$15,395	\$--
GT Capital (76G)	\$13,987	\$19,060	\$12,591	\$41,372	\$40,937	\$42,083	\$43,387
Total Capital	\$25,436	\$37,113	\$31,168	\$60,948	\$55,986	\$57,478	\$43,387
TURN ^(b)							
GD Expense (FHQ)				\$(1,807)			
GT Expense (JTX)				\$(1,073)			
Total Expense				\$(2,880)			
GD Capital (50N)				\$(19,576)	\$(15,049)	\$(15,395)	
GT Capital (76G)				\$(41,372)	\$(40,937)	\$(42,083)	\$(43,387)
Total Capital				\$(60,948)	\$(55,986)	\$(57,478)	\$(43,387)
(a) PG&E-16-E, p. 6-40, Table 6-17, line 1 (2020-2023 GD expense recorded and forecast amounts); PG&E-16-E, p. 6-41, Table 6-8, line 5 (2020-2022 GT expense recorded and forecast amounts); PG&E-3-ES, p. iii (GT 2023 expense forecast); PG&E-16-E, p. 6-6, Table 6-4, line 4 (Parties' recommendations); PG&E-16-E, p. 6-42, Table 6-9, line 5 (2020-2022 GD capital recorded and forecast amounts); PG&E-16-E, p. 6-43, Table 6-10, line 7 (2020-2022 GT capital recorded and forecast amounts); PG&E-3-ES, p. v (2023-2026 GD and GT capital forecasts). (b) TURN recommends no funding for the GD and GT M&C Station OPP Enhancements Program. TURN's recommended forecast reduction has been revised to match PG&E's Corrected Forecast resulting in a recommended forecast of \$0. PG&E-64, p. JCE 3-39 (MAT 50N), p. JCE 3-44 (MAT 76G); p. JCE 3-45 (MAT FHQ); and p. JCE 3-49 (MAT JTX).							

TURN witness Jonathan Lesser addressed this program and recommended no funding based solely on the RSE values for this program.⁷⁹⁸ No witness (including TURN's witness) directly addressed PG&E's testimony providing the operational reasons in support of this program.

⁷⁹⁸ TURN-02, p. 136, line 5 to p. 137, line 14.

3.5.3.1 The OPP Enhancement Program’s Operational Risk Drivers Are Undisputed

PG&E’s GT and GD M&C Station OPP Enhancements Program is designed to prevent overpressure or “OP” events due to equipment failure at pilot-operated gas regulator stations. Overpressure events that occur if the primary OPP regulator fails can result in loss of containment with ignition with significant impacts related to injuries and fatalities, loss of service, and/or equipment damage. PG&E’s OPP elimination strategy to address common mode failure through the installation of secondary OPP devices at pilot-operated regulator stations is driven by the following⁷⁹⁹:

- Causal Evaluations: PG&E has performed investigations on large OP events experienced between 2011 to present to determine the cause and to define actions to prevent recurrence. These investigations have helped identify some common causes for a number of these OP events, including gas quality, construction-related impacts, and common failure modes in pilot-operated regulator stations.⁸⁰⁰
- Recent Industry Events: After the Merrimack Valley, Massachusetts OP event in 2018, PG&E actively collaborated with other operators and contributed to regulatory and industry publications.⁸⁰¹ PG&E intends to reduce the likelihood of an over pressure event with similar results to the Massachusetts event through an engineering solution of installation of secondary over pressure protection, such as a slam shut device, at all the pilot-operated regulator stations that are subject to common mode failure.⁸⁰²
- Best Practices: PG&E’s practice of installing secondary OPP devices such as slam-shuts is recognized as one of the leading practices in the AGA report,

⁷⁹⁹ PG&E-03, p. 6-60, line 4 to p. 6-62, line 2.

⁸⁰⁰ PG&E-16-E, p. 6-20, lines 5-10.

⁸⁰¹ NTSB, Over pressurization of National Gas Distribution System, Explosions, and Fires in Merrimack Valley, Massachusetts (Sept. 13, 2018, Reissued Apr. 30, 2021), <<https://www.nts.gov/investigations/AccidentReports/Reports/PA1902.pdf>> (as of Oct. 2830, 2021), <<https://www.nts.gov/investigations/AccidentReports/Reports/PA1902.pdf>> (as of Oct. 28, 2022).

⁸⁰² PG&E-16-E, p. 6-20, lines 11-18.

“Leading Practices to Reduce the Possibility of a Natural Gas OP Event.”⁸⁰³ PG&E’s own experience has shown that the use of slam shut devices installed at PG&E’s LP distribution stations in the early 2000s have a proven track record for the prevention of OP events on these systems.⁸⁰⁴

- Anticipated Regulator/Compliance Requirement: The federal Protecting our Infrastructure of Pipelines and Enhancing Safety (PIPES) Act (Public Law 116-260) that was signed into law on December 27, 2020,⁸⁰⁵ has resulted in Rulemaking initiatives by PHMSA that would require operators to mitigate common failure mode conditions and have appropriate secondary OPP devices (e.g., slam-shuts, relief valves, etc.) to prevent and mitigate OP events. PG&E’s OPP program is consistent with this intent and PG&E initiated its program prior to these requirements.⁸⁰⁶

For these reasons, PG&E determined that addressing these threats proactively through this secondary OPP enhancements program is required as part of prudent gas system risk management and is a best practice.⁸⁰⁷ This program began in 2018 with the strategic objective to reduce OP events by addressing all pilot-operated regulator stations over a 10-year period.⁸⁰⁸

TURN did not take issue with any of PG&E’s testimony that describes the operational analysis and reasons for this program. Instead, TURN recommended eliminating this program based solely on its flawed RSE analysis. TURN’s RSE analysis is addressed above in Sections 2.3 and 3.2.2. above.

⁸⁰³ AGA, *Leading Practices to Reduce the Possibility of a Natural Gas Over-Pressurization Event* (Nov. 26, 2018), p. 7.
<<https://www.aga.org/contentassets/1e4dac45c7e94177a033844a6a90a109/leading-practices-to-prevent-over-pressurization-final.pdf>> (as of Oct. 28, 2022).
<<https://www.aga.org/contentassets/1e4dac45c7e94177a033844a6a90a109/leading-practices-to-prevent-over-pressurization-final.pdf>> (as of Oct. 28, 2022).

⁸⁰⁴ PG&E-16-E, p. 6-21, lines 19-22.

⁸⁰⁵ Consolidated Appropriations Act, 2021, Division R, Protecting our Infrastructure of Pipelines and Enhancing Safety Act of 2020 (PIPES Act),
<<https://rules.house.gov/sites/democrats.rules.house.gov/files/BILLS-116HR133SA-RCP-116-68.pdf>> (as of Oct. 28, 2022).

⁸⁰⁶ PG&E-16-E, p. 6-20 line 23 to p. 6-21 line 7.

⁸⁰⁷ PG&E-16-E p. 6-21, lines 18-24.

⁸⁰⁸ PG&E-03, p. 6-61, line 23 to p. 6-62, line 2.

Moreover, the only TURN witness to address this program, Jonathan Lesser, is not qualified to address the merits of the program. As TURN acknowledged in discovery, Dr. Lesser was not testifying as an expert in gas transmission or distribution operations; has not worked as an employee of a natural gas transmission or distribution utility; is not an expert on federal integrity management regulations; and had no experience working on any committee of the AGA.⁸⁰⁹

By contrast, as Director of Facility Integrity Management and Technical Services, PG&E witness Terry White was responsible for the Facility Integrity Management Program which is focused on the safety and reliability of gas transmission and distribution station facilities. He received a Bachelor of Science degree in Mechanical Engineering and is a California-Registered Professional Engineer in Mechanical Engineering. He has 28 years of experience in gas engineering and operations related to PG&E's underground storage facilities; compressor stations; pipeline terminals; and pressure regulation stations.⁸¹⁰ Mr. White is an active AGA member and is currently assigned to the AGA Measurement Committee.⁸¹¹

3.5.3.2 The OPP Program Is Not Addressing “Relatively Lower Risk Assets”

TURN incorrectly asserts that eliminating these programs is justified because PG&E will be addressing only “relatively lower risk assets” compared to those targeted in the early years of the program. However, all pilot-operated regulator stations are susceptible to common mode failure and carry the risk of large OP events.⁸¹² Contrary to TURN's argument, PG&E's proposed program is needed to address a significant portion of remaining pilot-operated facilities that carry the risk of large OP events during the 2023 GRC period.

⁸⁰⁹ PG&E-16-E, TURN's Response to PG&E Data Request PGE_TURN004-Q3(b), dated 6/22/22, p. AppA-388.

⁸¹⁰ PG&E-13, p. TW-1, lines 8-24.

⁸¹¹ PG&E-16-E, p. 6-24, lines 7-8.

⁸¹² PG&E-16-E, p. 6-22, lines 25-26.

There are approximately 1,300 GD pilot-operated regulator stations. PG&E expects to meet the strategic objective of installing secondary OPP at 50 percent of the pilot-operated GD regulator stations by the end of 2022. The 2023 GRC pace reflects the pace needed to complete the remaining 50 percent of secondary OPP installations at all GD regulator stations by the end of 2025.⁸¹³

Similarly, on the GT side of the program, there are approximately 457 large volume customer (LVC) facilities, that include large volume customer regulator (LVCR) sets and large volume customer meter (LVCM) sets, and 121 simple stations that fall under the category of pilot-operated regulator stations. While PG&E plans to address a majority of the LVCR facilities during the 2019-2022 period, work on the LVCMs and simple stations (which accounts for more than 80 percent of the stations) will begin in 2023. In addition to the risks inherent in pilot-operated regulators, LVCs also include customers with non-typical usage patterns such as factories, power plants, and agricultural processing facilities that have unique operational requirements with intermittent demands of relatively high volumes of gas. Intermittent load combined with failure of equipment to immediately close following the customer's rapid shut-in often results in over pressurizing the system downstream.⁸¹⁴

3.5.4 HPR Program – Capital (MWC 2K)

The function of regulator stations is to regulate and control pressure and provide protection of downstream assets from system pressure excursions. PG&E refers to spring-operated regulators as high pressure regulators or “HPRs.” HPRs are relatively small in size (90 percent of station HPRs are 3/4 inch in diameter, or less, and none are greater than 2 inches in diameter); they are used in district regulator stations serving a small gas demand.⁸¹⁵

⁸¹³ PG&E-03, p. 6-69, lines 7-13.

⁸¹⁴ PG&E-16-E, p. 6-22, line 14-32.

⁸¹⁵ PG&E-03, p. 6-39, lines 7-14.

PG&E developed the HPR Program to address gas leaks and facility conditions associated with HPR facilities. The scope of the program includes all HPR-type facilities, including Farm Tap HPR sets and HPR-type district regulator stations. HPRs are addressed by this program through several different options. Where possible and cost effective, units will be removed and eliminated from the system in lieu of replacement so subsequent maintenance will not be required. Alternatively, HPR units may be rebuilt or updated to an acceptable design configuration or converted to a district regulator station where appropriate. An additional option is to convert the HPR customer to a non-natural gas alternative source and then remove the HPR and associated service facilities.⁸¹⁶

PG&E is planning to replace 100 HPR units each year for the 2023-2026 period. This pace will effectively complete the HPR replacement program in 2026.⁸¹⁷ TURN is the only party that addresses this program and proposes:

TABLE 3-36
HPR PROGRAM (MWC 2K): PG&E’S CAPITAL FORECAST AND PARTIES
RECOMMENDED REDUCTIONS (\$000s)^(a)

Party	2020 Rec.	2021	2022	2023	2024	2025	2026
PG&E	\$47,081	\$60,496	\$64,656	\$17,853	\$18,299	\$18,720	\$19,151
TURN				\$(17,853) ^(b)	\$(18,299)	\$(18,720)	\$(19,151)

(a) PG&E-16-E, p. 6-42, Table 6-9, line 1 (2020-2022 recorded and forecast amounts); PG&E-3-ES, p. v (2023-2026 forecasts); PG&E-64, p. JCE 3-36 (TURN’s recommendation).

(b) TURN recommends no funding for the HPR Program. TURN’s recommended forecast reduction has been revised to match PG&E’s Corrected Forecast resulting in a recommended forecast of \$0.

None of PG&E’s testimony providing the operational reasons in support of this program was refuted by TURN or any other party. Nevertheless, TURN proposes the complete

⁸¹⁶ PG&E-03, p. 6-58, line 9 to p. 6-60, line 3.

⁸¹⁷ PG&E-03, p. 6-59, lines 4-9.

elimination of PG&E’s forecast for this program.⁸¹⁸ TURN incorrectly claims that low RSEs and benefit-cost ratios justify its recommendation.⁸¹⁹

The HPR program is an ongoing mitigation program that was developed to address gas leaks and facility conditions associated with HPR facilities.⁸²⁰ In 2011, in its Accelerated Gas Transmission System Aerial and Ground Leak Survey Trends Report, PG&E reported that the majority of leaks on the transmission system were on HPR facilities. Subsequently, the HPR mitigation program was established to rebuild or replace HPRs to address equipment deterioration, obsolescence, and legacy designs. This program was approved for implementation and adopted by the Commission in the 2011, 2014, 2017 and 2020 GRCs. Addressing equipment obsolescence and equipment failure is required as part of prudent gas system risk management and asset management strategy so that these facilities can be returned to normal maintenance and inspection activities.⁸²¹

TURN did not take issue with any of PG&E’s testimony that describes the operational analysis and reasons for this program. Only TURN witness Lesser addressed this program and recommended no funding based on the RSE scores for this program. TURN’s inappropriate use of RSE scores and Benefit Cost ratios as a basis to defund programs is addressed in Section 2.3 in this opening brief, and witness Lesser’s lack of qualifications with regard to operational gas issues is discussed above in Section 3.5.3.1.

TURN also asserts that from “the beginning of the 2023-2026 rate case period, PG&E should be addressing relatively lower risk assets compared to those it targeted in the early years of the program.”⁸²² TURN’s argument implies that once some of the high-risk assets are

⁸¹⁸ TURN-02, p. 138, lines 1-4.

⁸¹⁹ TURN-02, p. 118, line 15 to p. 119, line 3.

⁸²⁰ PG&E-03, p. 6-58, line 8 to p. 6-59, line 9.

⁸²¹ PG&E-16-E, p. 6-25, line 26 to p. 6-26, line 19.

⁸²² TURN-02, p. 118, lines 11-14.

addressed, the program can be discontinued. The HPR mitigation program was established, however, to address all HPRs that have age and obsolescence risk, not just a subset of high-risk assets as TURN recommends. HPR facilities were originally developed to serve individual customers directly off the transmission system (mostly rural areas). HPR facilities were not subject to the same maintenance and inspection that was required for district regulator stations. In addition, the condition and age of these facilities created safety risks within Gas Operations such as large over-pressurization events and the potential release of gas. Therefore, PG&E developed the program to assess all HPR facilities.⁸²³

This program has existed for a decade and is now approaching completion. While the higher risk stations have been addressed, there are still more than 400 HPRs affected by age and obsolescence risks that need to be addressed. Given the maturity of the program, PG&E is targeting a much slower pace compared to previous rate cases at 100 HPRs per year for the 2023 GRC period which will effectively complete the program in 2026.⁸²⁴ Upon completion of the HPR activities during the 2023 GRC period, these assets will be returned to a similar maintenance, inspection, and replacement schedule as the other types of regulator stations.⁸²⁵

3.5.5 GT C&P Compressor Replacements and Retirements: Los Medanos Compressor Replacement (MAT 76X)

The GT C&P Compressor Replacements and Retirements Program focuses on the management of PG&E's fleet of 41 compressor units installed at stations located in its GT pipeline system and underground gas storage facilities. The program includes both compressor replacements and retirements. Approximately 65 percent of the units in PG&E's compressor fleet are at or over 40 years old. Compressor replacements focuses on facilities typically in response to a specific driver (such as age, obsolescence, change in regulatory requirements, or

⁸²³ PG&E-16-E, p. 6-26, line 27 to p. 6-27, line 6.

⁸²⁴ PG&E-03, p. 6-59, lines 11-13.

⁸²⁵ PG&E-16-E, p. 6-26, lines 9-19.

lack of service or spare parts from manufacturers). Compressor retirements focuses on removal of facilities that are no longer required for system operation and that result in more efficient operation of the gas system. Together, Compressor Replacement and Retirement initiatives mitigate equipment related threats and risks that can adversely impact gas system operations through the loss of service, loss of operating flexibility and reliability, and inability to meet evolving industry and environmental regulations.⁸²⁶ TURN is the only party that addresses GT C&P Compressor Replacements and Retirements and proposes:

TABLE 3-37
GT C&P COMPRESSOR REPLACEMENTS AND RETIREMENTS (MAT 76X): PG&E’S
CAPITAL FORECAST AND PARTIES RECOMMENDED REDUCTIONS (\$000s)^(a)

Party	2020 Rec.	2021	2022	2023	2024	2025	2026
PG&E	\$5,792	\$2,347	\$15,104	\$19,154	\$19,632	\$20,094	\$15,418
TURN (Los Medanos & Tionesta)				\$(19,154) ^(b)	\$(19,632)	\$(20,094)	\$(15,418)
(a) PG&E-16-E, p. 6-43, Table 6-10, line 15 (2020-2022 recorded and forecast amounts); PG&E-3-ES, p. v (2023-2026 forecasts).; PG&E-64, p. JCE 3-44 (TURN’s recommendation). (b) TURN recommends no funding for GT C&P Compressor Replacements and Retirements. TURN’s recommended forecast reduction has been revised to match PG&E’s Corrected Forecast resulting in a recommended forecast of \$0.							

PG&E’s 2023 GRC forecast for MAT 76X reflects two projects: (1) Los Medanos K-1 Compressor Replacement, and (2) Tionesta Compressor Station Retirement. This Section 3.5.5 addresses the Los Medanos Compressor replacement. The Tionesta Compressor Retirement is addressed in Section 3.5.6 below.

For the 2023 GRC period, PG&E forecasts one compressor replacement project at the Los Medanos Storage Facility. The compressor replacement study identified Los Medanos K-1 to be replaced during the 2017-2020 timeframe, but the discussions about the possibility of decommissioning Los Medanos facility delayed the decisions on this compressor replacement. Consistent with the updated Peak Day Supply Standard, PG&E has determined that the

⁸²⁶ PG&E-03, p. 6-30, line 18 to p. 6-34, line 16.

Los Medanos Storage facility is required for system operations and will be replacing this compressor unit during the 2023 rate case period.⁸²⁷ Los Medanos K-1, a Cooper Bessemer GMVM V-12 (Quad) unit installed in 1981, is considered obsolete. There were few installations of this model compressor, technical support from the original equipment manufacturer (OEM) is declining, and there has been a notable cost increase in OEM replacement parts.⁸²⁸

PG&E forecasts a total capital expenditure of \$49.9 million for the Los Medanos K-1 compressor replacement project for the 2023 GRC period which includes costs to replace an obsolete compressor, replace associated equipment, install a compressor building, and any ancillary systems that must be upgraded to accommodate the new unit. The costs of the Los Medanos K-1 compressor replacement are forecast over a 4-year period and include \$10.0 million, \$10.0 million, \$15.0 million, and \$15.0 million in 2023, 2024, 2025, and 2026, respectively.⁸²⁹

In its initial testimony, TURN recommends that \$45.9 million of PG&E's \$49.9 million request to replace Los Medanos K-1 Compressor be disallowed. TURN claims that: (1) PG&E has not provided the required showing as to why asking ratepayers to pay for this work a second time is consistent with the deferred work principles agreed to in the Deferred Work Settlement; and (2) \$11.2 million was used to cover the cost overruns on the Burney compressor station project, leaving \$45.9 million of the amount adopted for the Los Medanos compressor replacement unaccounted for (\$57.0 million minus \$11.2 million).⁸³⁰ In rebuttal testimony, TURN argues that the Los Medanos gas storage facility is not needed and thus the replacement

⁸²⁷ PG&E-03, p. 6-32, lines 12-17.

⁸²⁸ PG&E-03, p. 6-32, lines 7-21.

⁸²⁹ PG&E-3-ES, WP 6-38, Line 10.

⁸³⁰ TURN-07, p. 40, lines 17-25.

for the Los Medanos compressor is no longer needed.⁸³¹ TURN's arguments are addressed below.

3.5.5.1 The Los Medanos Compressor Project is Not Deferred Work

The 2020 GRC Settlement Agreement requires PG&E to include testimony in this GRC on deferred work if the following criteria are met: (a) The work was requested and authorized based on representations that it was needed to provide safe and reliable service (Check 1); (b) PG&E did not perform all of the authorized and funded work, as measured by authorized (explicit or imputed) units of work (Check 2); and (c) PG&E continues to represent that the curtailed work is necessary to provide safe and reliable service (Check 3).⁸³²

For MAT 76X, Compressor Replacements, the results of this analysis are shown in PG&E's opening deferred work analysis workpaper.⁸³³ The answer to Check 1 is "Yes" because Compressor Replacement is an activity identified as safety, reliability, or maintenance. The answer to Check 2 is "Yes" because in the 2019 GT&S rate case two compressor replacement units were funded (Tionesta and McDonald Island Compressor Replacements), but only the McDonald Island replacement was performed. Thus, one unit of the two imputed units were performed. The answer to Check 3 is "No". As stated in the deferred work analysis workpaper, "No deferred work - One less unit compared to imputed – Tionesta compressor replacement forecasted for 2019-2022 period not completed due to change in Gas planning strategy and station will be retired instead in 2025." Based on these responses, and as explained in more detail below, PG&E correctly determined that there is no deferred work in the MAT 76X.

In the 2019 GT&S rate case, funding was neither requested nor authorized for the replacement of the Los Medanos K-1 Compressor. Funding for only two compressor

⁸³¹ TURN-21, p. 13, lines 1-5.

⁸³² PG&E-03, p. 6-102, lines 20-30.

⁸³³ PG&E-03, p. WP 6-105, line 2.

replacement units, McDonald Island and Tionesta, was requested and adopted in the 2019 GT&S rate case.⁸³⁴ Since there was no adopted funding for the Los Medanos K-1 Compressor replacement in the 2019 GT&S rate case, the Los Medanos K-1 Compressor replacement cannot be considered deferred work in the 2023 GRC deferred work analysis. Check 2 applies if “PG&E did not perform all of the authorized and funded work, as measured by authorized (explicit or imputed) units of work.” Since the Los Medanos K-1 Compressor replacement was not “authorized and funded” in the 2019 GT&S rate case, it is not subject to deferred work.⁸³⁵

TURN incorrectly argues that deferred work exists for Los Medanos compressor because the Commission originally authorized funding in the 2015 GT&S rate case, but the replacement was not performed. In the 2015 GT&S rate case decision, the Commission adopted \$28.7 million for Los Medanos Compressor replacement in 2017 subject to post-test year ratemaking and revenue requirement computation.⁸³⁶ For the 2015-2018 period, the total adopted forecast for MAT 76X was \$114.6 million⁸³⁷ to complete two compressor replacement projects: Burney K-2 and Los Medanos, which roughly equals \$57.3 million for each compressor replacement project.⁸³⁸ However, as part of PG&E’s Natural Gas Storage Strategy (NGSS) submitted in PG&E’s 2019 GT&S rate case application, PG&E proposed retiring the Los Medanos Storage facility. As a result of the proposal to close Los Medanos, the compressor replacement project forecast for the 2015-2018 GT&S rate case period was cancelled.⁸³⁹ In the 2019 GT&S rate case, no party, including TURN, recommended a disallowance or ratemaking

⁸³⁴ A.17-11-009, Exhibit PG&E-8, WP 7-60.

⁸³⁵ PG&E-16-E, p. 6-31, line 28 to p. 6-32 line 8.

⁸³⁶ D.16-06-056, p. 144.

⁸³⁷ The amount shown represents a new cost model view of the amount adopted in the 2015 GT&S Rate Case. For reference, the Commission adopted \$111 million (in the old cost model) for this program.

⁸³⁸ PG&E-16-E, p. 6-32, lines 11-17.

⁸³⁹ PG&E-16-E, p. 6-32, line 20 to p. 6-33, line 2.

adjustment for PG&E's decision not to replace the Los Medanos K-I compressor, and the Commission did not identify MAT 76X as a MAT code with deferred work in the 2019 GT&S Decision (D.19-09-025).⁸⁴⁰ The issue of deferred work related to not performing the Los Medanos compressor replacement as authorized in the 2015 GT&S case was therefore resolved in the 2019 GT&S case. To argue, as TURN does now, that the 2015 authorization for this project is the basis for a deferred work finding in the 2023 GRC is an improper attempt to undo the 2019 GT&S rate case decision.

TURN also ignores the fact that funds allocated to the Los Medanos compressor replacement in the 2015 GT&S rate case were reprioritized for other programs. Since PG&E did not perform the Los Medanos Compressor replacement in the 2015 GT&S rate case period, PG&E provided testimony in the 2019 GT&S rate case showing how the 2015 GT&S rate case funding related to the Los Medanos compressor replacement was reprioritized: "PG&E expects to spend \$38.2 million and \$9.5 million for 2015-2018 for the Physical Security and Upgrade Station Control programs compared to \$11.2 million and \$0 authorized in 2015 GT&S Rate Case."⁸⁴¹ Thus, PG&E spent a total of \$47.7 million, or \$36.5 million over adopted funding, on the Physical Security and Upgrade Station Controls programs. This spending is in addition to the reprioritization of funds within the Compressor Replacement program to cover the cost overruns due to incremental scope for the Burney Compressor replacement of approximately \$11.2 million⁸⁴² that was found reasonable by the Commission.⁸⁴³ As a result, PG&E reprioritized Los Medanos funding from the 2015 GT&S rate case to cover \$47.7 million of cost

⁸⁴⁰ PG&E-16-E, p. 6-35, lines 1-4. In the 2019 GT&S decision, the Commission determined deferred work existed for the following programs: External Corrosion Direct Assessment (ECDA, MAT HPC and HPN) D.19-09-025, p. 145, FOF 68 and COL 58; Internal Corrosion Direct Assessment (ICDA, MAT HPJ and HPO) D.19-09-025, p.145 and COL 59; and Capacity to Support Normal Operating Pressure Reductions (MWC 73), D.19-09-025, p. 216.

⁸⁴¹ PG&E-16-E, p. 6-34, lines 11-13, citing A.17-11-009, Exhibit (PG&E-1), p. 7-44, lines 24-27.

⁸⁴² TURN-07, p. 40, lines 15-17.

⁸⁴³ D.19-09-025, p. 101.

overruns for the Burney Compressor replacement, Physical Security and Upgrade Station control programs, not \$11.2 million as TURN claims.⁸⁴⁴

3.5.5.2 The Los Medanos Compressor Is Needed

In addition to its arguments regarding deferred work, TURN also maintains that the Los Medanos gas storage facility is no longer needed and thus there is no need for the compressor.⁸⁴⁵ The need for Los Medanos is addressed below in Section 3.6.4 below. Notably, TURN does not dispute the need for a new compressor if Los Medanos is retained.

3.5.6 GT C&P Compressor Replacements and Retirements: Tionesta Compressor Station Retirement (MAT 76X)

The GT C&P Compressor Replacements and Retirements program is summarized in Section 3.5.5 above. PG&E's 2023 GRC forecast for MAT 76X reflects two projects: (1) Los Medanos K-1 Compressor Replacement, and (2) Tionesta Compressor Station Retirement. Section 3.5.5 addresses the Los Medanos Compressor replacement. The Tionesta Compressor Retirement is addressed in this section.

In the 2019 GT&S rate case, PG&E forecast replacing the Tionesta K-1 compressor unit due to obsolescence. However, the results of the system planning studies⁸⁴⁶ conducted in 2020 have changed the long-term strategy and recommends retirement of the Tionesta facility in 2025. The retirement of the Tionesta facility will include two major activities: (1) removal of the Tionesta equipment, structures, and piping; and (2) conversion of the site to an M&C Complex station facility with remote controlled, main Line valves.⁸⁴⁷ PG&E's decision to not perform the replacement of the Tionesta Compressor Station and instead retire the unit was not

⁸⁴⁴ PG&E-16-E, p. 6-34, lines 19-22.

⁸⁴⁵ TURN-21, p. 13, lines 1-5.

⁸⁴⁶ PG&E performs system studies that identify the potential for reduced compression capacity. Based on the results of these studies, compressor units or facilities may be identified for retirement and decommissioning. PG&E-16-E p. 6-35, lines 22-25.

⁸⁴⁷ PG&E-03, p. 6-32, lines 22-34; see also PG&E-16-E p. 6-36, line 22 to p. 6-37, line 4 for detailed reasoning behind the decision to retire, and not replace the Tionesta station.

contested.⁸⁴⁸ PG&E forecasts a total capital expense of \$22.960 million for the Tionesta Compressor Station Retirement project for the 2023 GRC period. The cost of retirement is forecast over a 3-year period and includes \$9.184 million, \$9.184 million, and \$4.592 million in 2023, 2024, and 2025, respectively.⁸⁴⁹

TURN recommends a capital disallowance for the entire amount of PG&E's forecast in MAT 76X related to the Tionesta Compressor Station Retirement. TURN claims: "No deferred work showing has been offered, even though: (a) The work was requested and authorized based on representations that it was needed to provide safe and reliable service (Check 1); (b) PG&E did not perform all of the authorized and funded work, as measured by authorized (explicit or imputed) units of work (Check 2); and (c) PG&E continues to represent that the curtailed work is necessary to provide safe and reliable service (Check 3)."⁸⁵⁰

A discussion of PG&E's 2023 GRC deferred work analysis for MAT 76X that includes the Tionesta Compressor is provided in Section 3.5.5.1 above. To summarize, although PG&E performed only one of the two imputed units authorized in the 2019 GT&S case under MAT 76X (McDonald Island), there was no deferred work because PG&E is not seeking funding in the 2023 GRC for the second imputed compressor replacement unit that was not performed (Tionesta).⁸⁵¹ The Tionesta compressor replacement forecasted for 2019-2022 period was not completed due to a change in Gas planning strategy and the station will be retired instead in 2025. Thus, the forecasted work – compressor replacement - was not performed, and funding for this cancelled replacement project is not being requested again in the 2023 GRC.⁸⁵²

⁸⁴⁸ PG&E-16-E, p. 6-37, lines 7-9.

⁸⁴⁹ PG&E-3-ES, WP 6-38, line 7.

⁸⁵⁰ TURN-07, p. 41, lines 8-19.

⁸⁵¹ PG&E-16-E, p. 6-37, lines 14-19.

⁸⁵² PG&E-16-E, p. 6-38, lines 13-18.

Accordingly, the third criteria of the deferred work analysis—“PG&E continues to represent that the curtailed work is necessary” -- is not met.

The 2023 requested funding for retirement of the Tionesta compressor is new funding for a different project and work scope. No funding to retire the Tionesta Compressor Station was requested or approved in the 2019 GT&S rate case.⁸⁵³ The adopted funding that was not spent on Tionesta compressor replacement was subject to the overall capital portfolio reprioritization process for Gas Operations as described in PG&E’s Summary of Request and Investment Planning opening testimony.⁸⁵⁴ Furthermore, for the 2019-2022 GT&S rate case period, PG&E is forecast to incur capital expenditures of \$276 million over its 2029 GT&S adopted capital funding.⁸⁵⁵ For these reasons, PG&E did not receive a benefit from not spending \$22.96 million on the Tionesta Replacement and a disallowance in the 2023 GRC is therefore not warranted.

3.6 Asset Family - Storage

The Gas Storage asset family includes several asset types: (1) wells and reservoirs for underground storage facilities; (2) surface facilities; and (3) pipelines at the underground storage facilities. PG&E currently operates three storage facilities: McDonald Island, Los Medanos, and Pleasant Creek.⁸⁵⁶ In total, PG&E’s facilities include 109 injection and withdrawal wells equipped with over 200 miles of casing and tubing that extend approximately 1 mile into the earth to the storage reservoirs. Additionally, the gas storage asset family includes approximately 14 miles of transmission pipe (of which 4 miles are designated in HCA) and ancillary equipment, 271 surface and downhole safety valves, and 178 well measurement meters, wellhead separators,

⁸⁵³ PG&E-16-E, p. 6-38, lines 8-11.

⁸⁵⁴ PG&E-03, Ch. 2, Section E; PG&E-16-E, p. 6-38, line 32 to p. 6-39, line 2.

⁸⁵⁵ PG&E-03, p. 2-34, Table 2-8.

⁸⁵⁶ PG&E is currently in the process of seeking to sell or decommission the Pleasant Creek facility. PG&E-03, p. 7-59, lines 15-26.

and flow controls. PG&E also maintains a 25 percent interest in Gill Ranch storage facility that is operated by Gill Ranch Storage, LLC.⁸⁵⁷

PG&E's TY 2023 gas storage expense forecast is \$17.154 million. PG&E's attrition year forecasts are \$21.386 million for 2024, \$23.127 million for 2025, and \$43.630 million for 2026.⁸⁵⁸ PG&E's test-year expense forecast in the JCE is \$19.528 million in 2023.⁸⁵⁹

PG&E's gas storage capital expenditures forecast is \$88.009 million in 2021, \$86.444 million in 2022, and \$105.450 million in 2023, \$135.982 million in 2024, \$47.482 million in 2025, and \$18.553 million in 2026.⁸⁶⁰ PG&E's capital expenditures forecast in the JCE is \$93.669 million in 2021, \$99.300 million in 2022, and \$121.056 million in 2023, \$149.913 million in 2024, \$50.664 million in 2025, and \$19.300 million in 2026.⁸⁶¹

The only party that disputed PG&E's expense and capital forecasts was TURN. TURN also disputes PG&E's proposal for revisions to its Gas Storage Balancing Account (GSBA). In addition, Wild Goose Gas Storage, LLC (Wild Goose), Lodi Gas Storage, LLC (LGS), the Southern California Generation Coalition (SCGC), City of Palo Alto (Palo Alto), and TURN dispute PG&E's updated Peak Day Supply Standard as well as its proposal to retain the Los Medanos facility. TURN and SCGC/Palo Alto also raises issues regarding curtailment. The remainder of this section addresses these issues in the following order:

⁸⁵⁷ PG&E-03, p. 7-8, lines 4-16 (describing PG&E's gas storage asset family).

⁸⁵⁸ PG&E-3-ES, p. iii, reflects PG&E's rebuttal forecast updated with corrected escalation factors.

⁸⁵⁹ PG&E-64, p. 3-1, Table 3A-1, line 10.

⁸⁶⁰ PG&E-16-E, p. 7A-35, Table 7A-9, line 5 (2021 and 2022). PG&E-3-ES, p. v, which reflects PG&E's rebuttal forecast updated with corrected escalation factors.

⁸⁶¹ PG&E-64, p. 3-6, Table 3B-1, line 12 (2023); p. 3-10, Table 3B-2, line 12 (2022); and p. 3-14, Table 3B-3, line 12 (2021). Forecast amounts for 2024-2026, updated to include the September 2022 escalation adjustment, are provided for reference.

**TABLE 3-38
SUMMARY OF ISSUES ADDRESSED IN SECTION 3.6**

Section in Brief	Disputed Issue of Program	Impacted MATs
3.6.1	Uncertainty in Gas Storage Regulations	N/A
3.6.2	Updated Peak Day Supply Standard	N/A
3.6.3	Hourly Curtailment	N/A
3.6.4	Retention of Los Medanos, Drilling New Wells and Cross-Compression	N/A
3.6.5	Well Drilling – Capital	3L1
3.6.6	Well Reworks – Capital	3L3
3.6.7	Controls and Monitoring - Capital	3L5
3.6.8	Well Integrity Assessments - Expense	AH1
3.6.9	Well Reworks - Expense	AH2
3.6.10	Gas Storage Balancing Account	N/A

There are two additional programs in the Gas Storage Asset Family, Well Other (MAT AH3) and Well Engineering and Support (AH#), that had undisputed forecasts.⁸⁶² These undisputed MAT codes are included in Appendix A.

Finally, PG&E also proposed eliminating two accounts established in the 2019 GT&S rate case – the Below Ground Storage Decommissioning Balancing Account (BGSDBA) and the Cushion Gas Memorandum Account (CGMA).⁸⁶³ No party opposed the proposal to eliminate these two accounts. The undisputed proposal to close these accounts is reflected in Appendix B.

3.6.1 Uncertainty in Gas Storage Regulations and Rules

Before diving into the specifics of PG&E’s gas storage proposals and expense and capital forecasts, it is important to establish the context for PG&E’s requests. Federal and state regulations related to natural gas storage facilities have, in recent years, been in a state of considerable flux. In our opening testimony, we described in detail the recent changes and developments in PHMSA and California Department of Conservation, Geologic Energy Management Division (CalGEM) regulations that have occurred since the 2019 GT&S rate

⁸⁶² TURN-21, p. 14 (indicating these two MAT codes are undisputed).

⁸⁶³ PG&E-03, p. 7-63, line 12 to p. 7-64, line 23.

case.⁸⁶⁴ These regulations have been evolving and will continue to evolve during the 2023-2026 period. For example, even though CalGEM has approved some aspects of PG&E's Revised Implementation Plan, certain other aspects of the plan such as the frequency of well reinspections are still pending.⁸⁶⁵ PG&E's expense and capital forecast is based on the current PHMSA and CalGEM regulations. However, PG&E is also anticipating changes to these regulations that could impact its forecasts.

Some parties seek to reduce PG&E's forecasts based on wishful thinking that these regulations and rules will become less stringent. For example, TURN argues that PG&E has adopted a "worst-case scenario forecast" for potential CalGEM and PHMSA regulations regarding reinspections.⁸⁶⁶ However, as TURN acknowledges, the CalGEM and PHMSA regulations are, at best, in flux and "many questions regarding the details of compliance have yet to be resolved, including the pace and scope of work that will be performed."⁸⁶⁷ As PG&E detailed in its opening testimony, regulations and requirements have been changing significantly in recent years and will likely continue to change.⁸⁶⁸ PG&E's rate case forecasts reasonably and prudently take into account this regulatory uncertainty. The Commission should view with skepticism the rosy forecasts offered by some parties that regulations and rules will change in a manner that would reduce the costs of compliance. These parties' arguments are inconsistent with the history of gas storage rules and regulations or recent PHMSA and CalGEM developments.

⁸⁶⁴ PG&E-03, p. 7-12, line 22 to p. 7-17, line 11.

⁸⁶⁵ PG&E-03, p. 7-17, lines 1-11.

⁸⁶⁶ TURN-07, p. 23, lines 21-23.

⁸⁶⁷ TURN-07, p. 3, lines 16-18.

⁸⁶⁸ PG&E-03, p. 7-12, line 22 to p. 7-17, line 11.

3.6.2 PG&E's Updated Peak Day Supply Standard

One of the more contentious issues regarding natural gas storage is PG&E's updated Peak Day Supply Standard. The Peak Day Supply Standard is a forecast of potential customer demand for natural gas and available supply either from transmission pipelines or storage on a "peak day" over a ten-year period.⁸⁶⁹ The Peak Day Supply Standard is critical because it helps with necessary advance planning so that when a peak day event occurs, such as a particularly cold period of time, PG&E has sufficient gas transmission and storage resources available so that it does not have to shut off gas to customers. The updated Peak Day Supply Standard is intended to ensure that on a peak day for gas demand, PG&E can continue to safely and reliably operate its gas transmission and storage system.⁸⁷⁰

In the 2019 GT&S rate case, the Commission reviewed and approved a peak day supply standard (referred to in that proceeding as the Reliability Supply Standard or Reliability Standard) to determine an appropriate level of PG&E gas storage capacity.⁸⁷¹ Because the Peak Day Supply Standard in that case was prepared in 2017, almost 5 years ago, PG&E provided an updated Peak Day Supply Standard in this proceeding based on current information and forecasts.⁸⁷² The updated Peak Day Supply Standard analysis was presented in Exhibit PG&E-03, Table 7-15 and was accompanied by a detailed explanation of the source and basis for each element of the analysis.⁸⁷³ The updated Peak Day Supply Standard indicated that there would be potential gas storage capacity shortfalls starting in the 2021-2022 winter and getting progressively worse each year through the 2026-2027 winter.⁸⁷⁴ If a peak day event occurs

⁸⁶⁹ PG&E-03, p. 7-49, lines 1-16 (describing peak day demand).

⁸⁷⁰ PG&E-03, p. 7-46, lines 13-15.

⁸⁷¹ D.19-09-025, pp. 35, 40.

⁸⁷² PG&E-03, p. 7-47, lines 20-22.

⁸⁷³ PG&E-03, p. 7-48, Table 7-15 and line 1 to p. 7-52, line 10.

⁸⁷⁴ PG&E-03, p. 7-48, Table 7-15, line 18.

during these years, PG&E would have a capacity shortfall and be unable to provide gas to all of its customers (*e.g.*, shutoffs would be necessary). The capacity shortages and potential customer impacts in the later years, especially the 2024 to 2026 winters, could be substantial.

Parties did not dispute most of PG&E's updated Peak Day Supply Standard. However, parties do raise four specific issues: (1) whether PG&E was required to review updates to the Peak Day Supply Standard with parties prior to filing; (2) whether PG&E's forecasts are outdated; (3) the accuracy of the core demand forecast; and (4) the accuracy of the electric generation demand forecast. These issues, as well as the uncertainty associated with potential peak day needs, is addressed below.

3.6.2.1 Updating the Peak Day Supply Standard for the 2023 GRC

Wild Goose and LGS argue that the Peak Day Supply Standard in the 2019 GT&S rate case was negotiated as a part of a Memorandum of Understanding (2019 GT&S MOU) and that PG&E breached that agreement by submitting an updated Peak Day Supply Standard in this proceeding.⁸⁷⁵ This issue is readily addressed. As Wild Goose and LGS admit, the 2019 GT&S MOU expired at the end of the term of the 2019 GT&S rate case (*i.e.*, 2022) and was not precedential.⁸⁷⁶ At the hearing, TURN witness Michel Florio acknowledged this as well in response to ALJ Larsen's questions.⁸⁷⁷ There was no requirement in the 2019 GT&S MOU that the parties meet and confer in advance of PG&E's next rate case or that the parties confer regarding updates to the Peak Day Supply Standard in advance of PG&E's submission of its 2023 GRC.

⁸⁷⁵ WGL-02, p. 2, line 2 to p. 3, line 18. TURN also commented that it was disappointed that PG&E had not negotiated changes to the Peak Day Supply Standard in advance of filing the 2023 GRC but did not assert that PG&E has breached the 2019 GT&S MOU. See TURN-07, p. 4, lines 17-19.

⁸⁷⁶ PG&E-16-E, p. 7B-15, lines 17-25, citing Wild Goose and LGCS storage testimony and 2019 GT&S MOU which was included as an attachment to the Wild Goose and LGS testimony. See WGL-02, p. 5, lines 8-9; WGL-02, Attachment A, p. 11-ATCH1-7, § VII.c.

⁸⁷⁷ Tr. Vol. 13, 2500:11-12, TURN/Florio.

Wild Goose and LGS claimed that they relied on the Natural Gas Storage Strategy or “NGSS” adopted in the 2019 GT&S rate case to modify their operations, including implementing seven operational responsibilities described in the 2019 GT&S MOU.⁸⁷⁸ TURN echoes these concerns.⁸⁷⁹ These concerns are, at best, overstated. First, the seven operational responsibilities identified by Wild Goose and LGS in the 2019 GT&S MOU are only required if an independent storage provider (ISP) wants to execute contracts with PG&E’s Core Gas organization. Thus, Wild Goose and LGS did not undertake these responsibilities simply as a result of the 2019 GT&S MOU. Instead, these entities undertook these responsibilities because they wanted to execute contracts to serve Core Gas, which was to their own financial benefit.⁸⁸⁰

Second, Wild Goose and LGS candidly addressed in confidential discovery responses the cost and financial impact of these seven operational responsibilities. Wild Goose and LGS have not established that they incurred any significant costs due to their purported reliance on the 2019 GT&S MOU.⁸⁸¹

Finally, Wild Goose and LGS were well aware that PG&E’s gas storage needs and plans, including the proposal to decommission or sell the Los Medanos storage facility, could change. In the 2019 GT&S Rate Case decision, the Commission expressly stated:

Accordingly, to decommission Los Medanos, PG&E must file a Tier 2 Advice Letter on or after December 31, 2021, demonstrating that it has the requisite storage capacity to operate without the Los Medanos storage field. Until the PG&E’s Tier 2 Advice Letter is approved, PG&E is not permitted to remove more than half of the working gas at Los Medanos or sell or begin decommissioning activities at Los Medanos.⁸⁸²

⁸⁷⁸ WGL-02, p. 2, line 18 to p. 3, line 12; p. 3, line 19 to p. 4, line 5.

⁸⁷⁹ TURN-21, p. 7, line 18 to p. 8, line 10.

⁸⁸⁰ PG&E-16-E, p. 7B-16, lines 1-4, quoting WGL-02, Attachment A, p. 11-ATCH-6, § VI (2019 GT&S MOU).

⁸⁸¹ PG&E-34C, PGE_Joint-LW003, Question 3(c) and (d).

⁸⁸² D.19-09-025, p. 72.

Thus, Wild Goose and LGS understood that Los Medanos would not be sold or decommissioned if PG&E determined that it did not have the “requisite storage capacity” to operate without it. PG&E has demonstrated in this GRC that it does not have the requisite storage capacity needed to operate without Los Medanos or other more costly options.⁸⁸³

In short, PG&E did not violate the 2019 GT&S MOU, Wild Goose and LGS’ rhetoric regarding their detrimental reliance on the MOU is inconsistent with the actual facts, and all parties were on notice that if the need for gas storage facilities changed, PG&E may retain Los Medanos. Thus, the parties’ arguments concerning PG&E’s compliance with the 2019 GT&S MOU are misplaced.

Wild Goose, LGS, and TURN also make arguments regarding the alleged anti-competitive impact of retaining Los Medanos. These arguments are addressed below in Section 3.6.4.3.

3.6.2.2 PG&E’s Forecasts Are Not Outdated

TURN argues that PG&E’s forecasts in its Peak Day Supply Standard analysis are outdated.⁸⁸⁴ This is incorrect. PG&E’s June 30, 2021 testimony used the most current forecasts available at that time.⁸⁸⁵ The 2022 California Gas Report with updated demand forecasts was issued after PG&E submitted its testimony. PG&E provided this updated information in rebuttal testimony. The updated information shows that peak day demand forecasts are actually increasing and thus the capacity shortfall identified in the Peak Day Supply Standard analysis is even more acute.⁸⁸⁶

⁸⁸³ PG&E-16-E, p. 7B-16, lines 22-27.

⁸⁸⁴ TURN-07, p. 6, lines 3-5.

⁸⁸⁵ PG&E-16-E, p. 7B-9, lines 16-18.

⁸⁸⁶ Compare PG&E-03, p. 7-48, Table 7-15, lines 1-5 and PG&E-16-E, p. 7B-13, Table 7B-1, lines 1-5 (showing increase in the 2022-2027 demand forecast based on updated information).

3.6.2.3 Core Demand Forecast

The main driver for the natural gas demand on a peak day is core customer usage. TURN, Wild Goose, and LGS dispute PG&E's core demand forecast based on several flawed assumptions. First, TURN argues that because average daily demand is forecasted to decrease, peak day demand should decrease as well.⁸⁸⁷ However, average demand and peak day demand are not the same. The average day forecast is the average consumption by a group of customers over the entire year. In the case of core customers, an average day forecast averages high winter use and very low summer use. A peak day forecast, on the other hand, reflects extreme cold weather that is expected to occur once in a 10-year period.⁸⁸⁸ As PG&E witness Roger Graham testified at the hearing "there is not necessarily a good relationship between average demand and peak-day demand but they can move in opposite directions. I don't see any conflict between the [average day and peak day demand forecasts]."⁸⁸⁹

Second, TURN argues that because customers are making energy efficiency improvements and that California is undertaking a "serious effort at building electrification," peak demand should decline.⁸⁹⁰ However, energy efficiency improvements which may impact day-to-day gas usage do not necessarily translate into reduced gas consumption on peak days. Rather, gas consumption at times when it is much colder than normal (*i.e.*, peak days) is more complex and requires sophisticated forecasting techniques to extrapolate consumption during weather conditions rarely experienced.⁸⁹¹ PG&E has contracted with Marquette Energy Analytics (MEA), a firm with recognized expertise in gas demand modeling, to create and update our core customer peak day forecast model. PG&E used MEA model forecasts for the core

⁸⁸⁷ TURN-07, p. 8, lines 1-3; p. 10, lines 15-17.

⁸⁸⁸ PG&E-16-E, p. 7B-10, lines 8-15.

⁸⁸⁹ Tr. Vol. 6, p. 960:24-28, PG&E/Graham; see also Tr. Vol. 6, 961:1-22, PG&E/Graham (explaining differences between average day and peak day forecasts).

⁸⁹⁰ TURN-07, p. 8, lines 1-8.

⁸⁹¹ Tr. Vol. 6, 963:4-18, PG&E/Graham.

demand included in its updated Peak Day Supply Standard analysis.⁸⁹² As PG&E explained to TURN in discovery:

Bi-Annually PG&E commissions Marquette Energy Analytics (MEA) to conduct a Design Day Core Demand Analysis. In the analysis, MEA uses their proprietary software to analyze the previous two years of recorded (12 months at a time) historical system composite temperatures and system core demands are analyzed (regression analysis) to develop and update temperature verse core demand curves.⁸⁹³

PG&E also explained in discovery that the MEA analysis was used for the initial Peak Day Supply Standard analysis submitted in the 2019 GT&S Rate Case and was used in this proceeding, except updated.⁸⁹⁴ Rather than retaining its own expert, TURN simply offers anecdotes and various pieces of information to justify its argument that core customer peak day demand should be declining.⁸⁹⁵

Third, Wild Goose and LGS argue that PG&E's demand forecasts, including core demand, are only based on two years of data, which they argue is not sufficient for a forecast through 2027.⁸⁹⁶ While MEA updates its forecasts with the most recent two years of data, the MEA models use substantially more historical information. Thus, Wild Goose and Lodi's concerns are unfounded. Nor do Wild Goose and Lodi offer an alternative analysis regarding core demand.

Fourth, TURN, Wild Goose and LGS argue that the peak day core demand in the last 10 years occurred in December 2013 and was 2,384 MMcf/d, which is lower than the core demand reflected in PG&E's updated Peak Day Supply Standard analysis.⁸⁹⁷ However, as PG&E

⁸⁹² PG&E-16-E, p. 7B-10, lines 24-29; see also Tr. Vol. 6, 962:1-25, PG&E/Graham (describing MEA's work).

⁸⁹³ PG&E-16-E, PG&E's response to Data Request TURN_003-Q51, dated 8/30/21, p. AppA-321.

⁸⁹⁴ *Id.*

⁸⁹⁵ TURN-07, p. 8, lines 14-16.

⁸⁹⁶ WGL-01, p. 8, lines 8-17.

⁸⁹⁷ WGL-03, p. 1, line 22 to p. 2, line 5; TURN-07, p. 7, line 6 to p. 8, line 16.

witness Graham explained at the hearing, there are numerous reasons why the peak day core demand forecast would be higher than a date which occurred almost a decade ago (*i.e.*, December 2013) including the undisputed fact that PG&E has interconnected thousands of new core customers in the intervening decade.⁸⁹⁸ Given the substantial number of new core customers added since 2013, it is entirely reasonable that the peak day demand going forward would be higher than it was a decade ago.

Fifth, TURN argues that the core demand peak demand forecast from the 2019 GT&S rate case (which were developed in 2017) should be used in the updated Peak Day Supply Standard analysis, rather than the forecasts used by PG&E.⁸⁹⁹ This proposal relies on outdated data from a previous rate case and ignores: (1) the more recent data used by MEA to forecast core customer peak day demands that PG&E incorporated into its Peak Day Supply Standard analysis; and (2) the fact that PG&E has continued to connect new core gas customers since the 2019 GT&S rate case. It is also notable that MEA prepared the peak day demand forecast for the 2019 GT&S case, which TURN now proposes the Commission rely on.⁹⁰⁰ There is no reason to use an outdated core gas demand forecast when a more recent forecast, prepared by exactly the same experts, is now available. The Commission should not simply adopt TURN's core demand forecast when recognized experts using updated data have provided a more accurate analysis.

Finally, when considering the core demand forecast, as well as the electric generation forecast described below in Section 3.6.2.4, the Commission should keep in mind its admonition in the 2019 GT&S rate case concerning the importance of using conservative estimates for issues as critical as the ability of PG&E's gas system to have enough capacity to serve customers. In that case, with regard to the Reliability Standard, the Commission explained:

⁸⁹⁸ Tr. Vol. 6, 972:18 to 973:6, 973:19 to 974:10, PG&E/Graham.

⁸⁹⁹ TURN-07, p. 8, lines 10-16.

⁹⁰⁰ PG&E-16-E, p. 7B-11, lines 14-17.

Moreover, using a higher demand estimate is a conservative approach that is reasonable given the extent to which the NGSS will change PG&E's operations and the fact that the objective of the Reliability Standard is to ensure that PG&E has enough supply to meet peak demand during system outages and other emergencies.⁹⁰¹

Where, as is the case in this proceeding, there is a significant potential for uncertainty in forecasts and the potential for significant regulatory changes in the future, the Commission should be careful before adopting parties' unsupported rosy forecasts of peak day demand. Instead, the focus the Commission decision should make sure that PG&E has enough supply to meet demand during system outages and other emergencies.

3.6.2.4 Electric Generation Demand Forecast

The second primary driver for peak day demand is natural gas used by electric generating units. TURN disputes PG&E's electric generation demand forecast arguing: (1) the forecast does not reflect the Preferred System Plan for renewable resources adopted by the Commission in D.22-02-004;⁹⁰² (2) the retirement of the Diablo Canyon Power Plant (Diablo Canyon or DCPP) should not increase the electric generation demand in any given year above a base year 2023-2024;⁹⁰³ (3) the core and electric generation demands will not peak on the same day⁹⁰⁴; and (4) PG&E should have used a "power flow analysis."⁹⁰⁵ None of these arguments has merit.

First, while TURN criticizes PG&E for not using the Preferred System Study which reflects increased renewable generation (*i.e.*, not natural gas fired), PG&E could not have used it as it submitted its opening testimony on June 30, 2021 and the Preferred System Plan was not

⁹⁰¹ D.19-09-025, p. 29.

⁹⁰² TURN-07, p. 8, lines 18-22.

⁹⁰³ TURN-07, p. 9, line 25 to p. 10, line 2.

⁹⁰⁴ TURN-07, p. 10, lines 3-14.

⁹⁰⁵ TURN-07, p. 14, lines 1-7.

approved until February 2022.⁹⁰⁶ However, PG&E would agree to use an updated peak day demand forecast from the 2022 California Gas Report which does incorporate the Preferred System Plan from D.22-02-004. PG&E provided the demand forecasts from this report in its rebuttal testimony. The report forecasts higher electric generation demand from 2022-2027 than PG&E forecast in its opening testimony.⁹⁰⁷ Thus, even considering the Preferred System Plan, electric generation gas demand is not likely to substantially decrease over the rate case period.

Second, TURN's argument that the generation lost from the closure of Diablo Canyon will be replaced with non-gas fired generation and that electric generation gas demand should not exceed the base year 2023/2024 demand is flawed.⁹⁰⁸ TURN assumes that none of the new renewable resources intended to replace Diablo Canyon will begin generating before Diablo Canyon is shut down. However, many of the new renewable resources will come online over an extended period of time including significant amounts prior to the closure.⁹⁰⁹ Therefore, some of the new resources referred to by TURN are already reflected in the base year (2023/2024) chosen by TURN. When Diablo Canyon is retired there will not necessarily be an increase in renewable generation from the prior year. Instead, it is more likely there will be an increase in gas fired generation compared to the base year.⁹¹⁰ We recognize that given recent events, there is some uncertainty regarding the retirement date of Diablo Canyon. That uncertainty, however, supports a more conservative approach, as the Commission decided in the 2019 GT&S decision.⁹¹¹ If Diablo Canyon does retire as scheduled, it is critical that Los Medanos be

⁹⁰⁶ PG&E-16-E, p. 7B-12, lines 19-21.

⁹⁰⁷ Compare PG&E-03, p. 7-48, Table 7-15, line 3 (original electric generation demand forecast used by PG&E in opening testimony) and PG&E-16-E, p. 7B-13, Table 7B-1, line 3 (2022 California Gas Report updated electric generation forecast).

⁹⁰⁸ TURN-07, p. 9, line 11 to p. 10, line 2.

⁹⁰⁹ PG&E-16-E, p. 7B-13, lines 18-20.

⁹¹⁰ PG&E-16-E, p. 7B-13, line 22 to p. 7B-14, line 2.

⁹¹¹ D.19-09-025, p. 29.

available to support existing gas fired generation that will replace it. In addition, there are other considerations beside the closure of Diablo Canyon, such as the increase electric demand to fuel electric cars, general economic growth, and the growth of all electric homes, that may increase the peak day need for gas fired generation.⁹¹²

Third, TURN argues that core customer and electric generation gas demand will not peak on the same day and thus PG&E's Peak Day Supply Standard forecasted demand is overstated.⁹¹³ As TURN points out in its testimony, December 9, 2013 was a 1-in-10 year peak day.⁹¹⁴ While TURN notes that core demand on that day peaked at 2,384 million cubic feet (mmcf)/d, it neglects to mention that the electric generation demand on that same day peaked at 1,420 mmcf/d, which was one of the highest demand days in the winter ever. Contrary to TURN's assertion, it is clearly possible for core customer and electric generation demand to peak on the same day.⁹¹⁵ Moreover, even TURN's own analysis demonstrates that approximately 23% of the time there is a correlation between core customer peak demand and electric generation peak demand.⁹¹⁶ TURN attempts to minimize this fact by stating that there were not similar correlations in the two most recent winters. However, looking at the entire ten years of data developed by TURN, there is certainly strong evidence of a correlation between peak demand days for core customers and peak demand days for electric generation.⁹¹⁷ As PG&E witness Roger Graham explained at the hearing:

PG&E needs to plan for the 23 [percent]. We don't get to plan for, you know, the average, we're planning for an expected peak. I think the 23 percent chance

⁹¹² PG&E-16-E, p. 7B-14, lines 2-6.

⁹¹³ TURN-07, p. 10, line 3 to p. 12, line 10.

⁹¹⁴ TURN-07, p. 7, lines 8-10.

⁹¹⁵ PG&E-16-E, p. 7B-14, lines 9-15.

⁹¹⁶ TURN-07, p. 11, lines 12-16.

⁹¹⁷ PG&E-16-E, p. 7B-14, lines 15-22.

they're going to be coincident [peak for electric generation and core customer demand] is something we should plan for.⁹¹⁸

Fourth, TURN is correct that PG&E did not use a power flow analysis for its electric generation demand forecast submitted in opening testimony. PG&E switched in May 2021 to a different tool, the PLEXOS production cost modeling tool to forecast electric generation gas demand based on power system simulations. PLEXOS can provide forecasts on a daily and hourly basis. The results from PLEXOS were not available in time to be incorporated into PG&E's opening testimony. The previous tool only forecast demand on a monthly interval therefore could not produce an accurate peak day demand forecast.⁹¹⁹ However, the original peak day forecast for electric generation is still a reasonable forecast reflecting the information and tools available at the time of filing. More importantly, the 2022 California Gas Report did use a power flow analysis and is forecasting higher electric generation peak day demand than the forecast in PG&E's opening testimony.⁹²⁰

Wild Goose, LGS, and TURN make an additional argument that the peak day demand forecast for electric generation in this proceeding is substantially higher than the electric generation forecast in the 2020 California Gas Report.⁹²¹ However, as TURN acknowledges, the electric generation numbers that it was referring to in the 2020 California Gas Report are for average daily winter demand, not peak day demand.⁹²² While the daily demand over an entire month may be lower as a result averaging, any given peak day the demand can be very high. The standard for storage planning is to address peak day usage, not averages. Moreover, the peak day demand forecast from the 2022 California Gas Report, which is more recent than the

⁹¹⁸ Tr. Vol. 6, p. 982:10-15, PG&E/Graham.

⁹¹⁹ PG&E-16-E, p. 7B-13, lines 3-11.

⁹²⁰ PG&E-16-E, p. 7B-12, lines 25-26 and p. 7B-13, Table 7B-1.

⁹²¹ TURN-07, p. 10, line 15 to p. 11, line 8; WGL-3, p. 2, lines 6-10.

⁹²² TURN-07, p. 10, lines 18-20.

report cited by TURN, indicates a higher forecast for electric generation than was in PG&E's opening testimony.⁹²³

Finally, Wild Goose, LGS, and TURN cite forecasts for average temperature year and 1-in-35 year average annual gas demand from the Cost Allocation and Rate Design (CARD) proceeding (A.21-09-018) as a basis for arguing that the electric generation peak day demand forecast should be lower.⁹²⁴ They mix apples and oranges. The forecasts used in the CARD proceeding are demand averages over a period of time, while peak day demand occurs on a single day (or multiple days in certain conditions). As PG&E witness Graham explained "[w]e don't get to plan for . . . the average, we're planning for an expected peak."⁹²⁵ Mr. Graham went on to explain:

Q Okay. So it's your position that 1-in-10-year peak-day demand, which we're talking about in this case, is going to increase even though 1-in-35-year cold year demand is in -- is decreasing in the CARD case; is that correct?

A That's correct. As you noted in asking the question, the CARD case is an annual forecast. It's for every day of the year even though it's for, quote, a cold year which is temperatures that would be colder than normal, but it's for 100 percent of the year, 365 days, which are -- there's lots of days that aren't cold even in a cold year, like all summer. Where the peak-day demand forecast is looking at a single event, a cold event, that might occur once every 10 years, and then the demands are very different during cold events than during an average day in August or an average day in March or all the other days that represent an average for a calendar year.⁹²⁶

In short, TURN, Wild Goose, and LGS have failed to offer any reasoned basis for rejecting PG&E's electric generation demand forecast, which is based on reasonable assumptions and consistent with the recent 2022 California Gas Report.

⁹²³ Compare PG&E-03, p. 7-48, Table 7-15, line 3 and PG&E-16-E, p. 7B-13, Table 7B-1, line 3.

⁹²⁴ TURN-07, p. 10, lines 9-14; WGL-03, p. 2, lines 11-16.

⁹²⁵ Tr. Vol. 6, p. 982:11-12, PG&E/Graham.

⁹²⁶ Tr. Vol. 6, 961:1-22, PG&E/Graham.

3.6.2.5 PG&E's Peak Day Supply Standard Should Be Approved

Other than disputes about core customer and electric generation peak day demand, no other aspect of PG&E's updated Peak Day Supply Standard analysis is disputed. As PG&E demonstrated above, the disputes about core customer and electric generation demand are without merit, and thus the Commission should adopt the updated Peak Day Supply Standard presented by PG&E, which is based on substantial evidence and analysis of current data.⁹²⁷

Approving the Peak Day Supply Standard is not merely a theoretical exercise, it has real world consequences. Based on this analysis, PG&E has put forward a proposal to address the capacity shortfall. Notably, even TURN acknowledges that the proposal selected by PG&E would be reasonable if PG&E's Peak Day Supply Standard is correct.⁹²⁸ PG&E's proposal involves drilling new wells at Mc Donald Island and Gill Ranch, retaining the Los Medanos facility, and installing cross-compression.⁹²⁹

TURN, Wild Goose, and LGS argue that the retention of Los Medanos and drilling new wells is not necessary because they believe the peak day demand will be lower than forecasted by PG&E. This is wishful thinking. If they are wrong, however, PG&E's customers will bear the impact. This wishful thinking does not take into consideration that uncertainty, future events, and regulations may significantly impact PG&E's ability to meet customer demand. With regard to regulations, Mr. Graham explained in its opening testimony:

One of the primary drivers for changes between PG&E's 2019 NGSS forecast and the updated Peak Day Supply Standard analysis presented here is changes in CalGEM requirements for well reinspection intervals. At the time of the 2019 GT&S Rate Case, the reinspection interval requirements were not fully established by either PHMSA or CalGEM and it was not clear that a reinspection would need to occur within the first seven years after a well is retrofitted. In the 2019 GT&S Rate Case, PG&E assumed that reinspections would not be required within the first seven years of a retrofit given this uncertainty. However,

⁹²⁷ PG&E-03, p. 7-47, line 13 to p. 7-52, line 10 (describing data and analysis supporting Peak Day Supply Standard).

⁹²⁸ TURN-07, p. 17, line 14 to p. 19, line 14.

⁹²⁹ PG&E-03, p. 7-52, lines 23-25.

CalGEM has now indicated that reinspections may be required sooner than a risk-based frequency.... Reinspections require that a well be taken out of service and has prolonged outage impact. The level and frequency of reinspections mandated by the CalGEM regulations will require PG&E to have some wells out of service for reinspections during the peak winter months which reduces the withdrawal capacity of McDonald Island more than anticipated. Thus, additional storage capacity is needed to meet system reliability and safety needs.⁹³⁰

And more generally, as Mr. Graham explained in his rebuttal testimony:

The Commission should be concerned with revisions to the Peak Day Supply Standard analysis that effectively reduce the capacity shortage. While these revisions may appear to be theoretical, changes to the capacity shortage forecast can result in changes to PG&E's storage-related capital investment. Insufficient capital investments and a greater capacity shortfall than forecast can result in inadequate capacity and supply diversity and lead to substantial economic harm to PG&E's customers. The Commission does not need to look far to see the impact of limited supply capacity has had on the customers served by SoCalGas or impact inadequate supplies had on the electric reliability in Texas in February 2021.⁹³¹

The Commission should reject proposals that are premised on the speculative “hope” that uncertainties will not occur, peaks will not be coincident, demand will go down, and regulations will not impact supply. Instead, the Commission should adopt a proposal that even TURN agrees is the “least cost” option⁹³² to address the supply shortage demonstrated in PG&E's updated Peak Day Supply Standard analysis.

3.6.3 Hourly Curtailment

Under the NGSS adopted in the 2019 GT&S rate case, PG&E provides two services in relation to its gas storage facilities. The first is Inventory Management which includes gas storage capacity needed to operate the system and to meet large intraday swings in demand created by core and electric generation gas customers.⁹³³ This service is not in dispute.

⁹³⁰ PG&E-03, p. 7-51, line 25 to p. 7-52, line 10.

⁹³¹ PG&E-16-E, p. 7B-14, line 26 to p. 7B-15, line 5.

⁹³² TURN-07, p. 19, lines 6-9.

⁹³³ PG&E-03, p. 7-46, lines 22-26; see also D.19-09-025, pp. 30, 34-35 (describing Inventory Management).

The second service is Reserve Capacity, which is intended to provide the PG&E system with an intraday supply of natural gas in case of significant unplanned equipment outages or other supply problems such as forecasting errors, reduction of supply at an interconnect, demand forecast uncertainty, or a pipeline outage.⁹³⁴ Reserve Capacity is disputed. SCGC/Palo Alto and TURN argue that PG&E should have considered hourly curtailment as an alternative to Reserve Capacity and, if PG&E had done so, it could eliminate or significantly reduce Reserve Capacity. Because Reserve Capacity is included in the Peak Day Supply Standard, if it was eliminated, PG&E's capacity shortfall would be less and, TURN and SCGC/Palo Alto argue, the need for Los Medanos or other PG&E proposals would be eliminated as well.

SCGC/Palo Alto and TURN raise three specific arguments regarding Reserve Capacity: (1) PG&E did not consider how hourly curtailments would impact Reserve Capacity as mandated by the 2019 GT&S rate case decision (D.19-09-025); (2) hourly curtailments could be used in lieu of Reserve Capacity; and (3) if PG&E uses hourly curtailments to eliminate Reserve Capacity, Los Medanos would no longer be needed. Each of these arguments is addressed below.

3.6.3.1 PG&E Considered Hourly Curtailments Related to Reserve Capacity In Its Opening Testimony

In the 2019 GT&S rate case decision, the Commission directed PG&E to consider “whether and to what extent using an hourly curtailment process would allow [PG&E] to offset some of the inventory volumes that are allocated for the Reserve Capacity service.”⁹³⁵ The Commission had a similar requirement for Inventory Management.⁹³⁶ SCGC/Palo Alto and TURN agree that PG&E satisfied the Inventory Management requirement, but assert that PG&E

⁹³⁴ PG&E-03, p. 7-47, lines 1-4; PG&E-16-E, p. 7B-5, lines 3-12; see also D.19-09-025, pp. 35, 40 (describing Reserve Capacity).

⁹³⁵ D.19-09-025, p. 40.

⁹³⁶ D.19-09-025, pp. 34-35.

did not evaluate whether hourly curtailment could reduce the amount needed for Reserve Capacity.⁹³⁷ This assertion is simply wrong.

In his opening testimony, PG&E witness Roger Graham expressly stated:

In this section, we explain our current curtailment process and why hourly curtailments are not reasonable or cost-effective for customers. For the reasons explained below, PG&E proposes continued use of the Inventory Management and Reserve Capacity Services rather than adopting a process for hourly curtailments.⁹³⁸

In other words, the curtailment analysis presented by Mr. Graham applied to both Inventory Management and Reserve Capacity. In his analysis, Mr. Graham concluded that hourly curtailment was in appropriate for either Inventory Management or for Reserve Capacity.⁹³⁹ Mr. Graham confirmed this to SCGC/Palo Alto in a discovery response provided February 2, 2022, almost five months before SCGC/Palo Alto submitted their testimony.⁹⁴⁰ Thus, PG&E fully satisfied the requirements of the 2019 GT&S rate case decision in its opening testimony.

3.6.3.2 Hourly Curtailments Cannot Replace Reserve Capacity

On the merits, SCGC/Palo Alto and TURN argue that hourly curtailments can be used to replace Reserve Capacity.⁹⁴¹ These parties' arguments are not supported by the evidence and should be rejected.

In our opening testimony, we provided three reasons why curtailment could not be used in lieu of Reserve Capacity. First, to effectively implement curtailments, PG&E needs to be able to accurately forecast when a curtailment will occur so that it only issues curtailment notices

⁹³⁷ SCGC/PA-01-E, p. 2, line 2 to p. 3, line 17; TURN-21, p. 4, lines 3-11.

⁹³⁸ PG&E-03, p. 7-56, lines 1-6.

⁹³⁹ PG&E-03, p. 7-55, line 15 to p. 7-59, line 7.

⁹⁴⁰ PG&E-36, PG&E's response to SCGC-PA_001-Q003 (explaining the hourly curtailment analysis applied to Reserve Capacity).

⁹⁴¹ SCGC/Palo Alto-01-E, p. 4, line 21 to p. 9, line 8; TURN-21, p. 6, line 18 to p. 7, line 12.

when absolutely necessary. However, because Reserve Capacity is intended for unplanned equipment outages, a reduction of supply at the interconnect, a pipeline outage, or demand forecast error, the outages that would be addressed by Reserve Capacity cannot be easily forecasted in advance. In order to protect system integrity, PG&E would be required to call substantially more curtailments than actually needed given the last minute nature of many of issues addressed by Reserve Capacity which can only be known immediately before an event occurs.⁹⁴²

Second, given that the need for a curtailment cannot be forecasted, curtailments would need to occur in near real time. Real time curtailments will suffer significant compliance problems (*i.e.*, parties receiving the curtailment notice will not respond and curtail their natural gas demand). Outages can occur anytime during a 24-hour day including in the middle of the night. Many noncore facilities, such as large office complexes and universities, may not be fully staffed to receive a curtailment message and/or have enough qualified staff to implement a curtailment with little or no notice in the middle of the night.⁹⁴³ If customers are not able to comply with a curtailment order because they do not have sufficient time or ability to respond, there is a substantial risk that the curtailments will not be effective and, as a result, there will be detrimental impacts on gas system reliability.

Third, most of PG&E's noncore gas customers do not have meters PG&E can read and monitor in real time.⁹⁴⁴ It is important for PG&E's Gas Control Center to know if the curtailments are actually occurring. If we do not get the required relief from a curtailment order, we must implement an orderly shutdown of local transmission or distributions systems to avoid uncontrolled outages. This ability to monitor and respond to noncompliance activities clearly

⁹⁴² PG&E-03, p. 7-56, line 17 to p. 7-58, line 9; PG&E-16-E, p. 7B-3, line 14 to p. 7B-4, line 3.

⁹⁴³ PG&E-03, p. 7-58, lines 10-18.

⁹⁴⁴ PG&E-03, p. 7-58, lines 19-31.

applies to real time curtailments when the reason for the curtailment is to avoid uncontrolled outage on the gas system versus for economic needs.

Despite these operational challenges and limitations, SCGC/Palo Alto and TURN insist that hourly curtailments are possible and can eliminate the need for Reserve Capacity. To support this argument, SCGC/Palo Alto focus narrowly on unplanned equipment outages and argues that unplanned outages are unlikely to occur during a peak day event.⁹⁴⁵ However, this argument assumes the only issue addressed by Reserve Capacity is an unplanned outage, which is not the case. Reserve Capacity Service is needed to address multiple situations in addition to unplanned equipment outages, such as forecasting errors, reduction of supply at an interconnect, demand forecast uncertainty, and a pipeline outage.⁹⁴⁶ Even more important is that the types of outages addressed by Reserve Capacity can occur at the same time. For example, there may be an unplanned outage, planned pipeline outage, and demand higher than forecast all on the same day, which results in compound impacts and makes the need for Reserve Capacity Service even more important.⁹⁴⁷ Thus, SCGC/Palo Alto's analysis is flawed because it is narrowly focused on one aspect of Reserve Capacity (*i.e.*, unplanned outages).

SCGC/Palo Alto and TURN point to curtailment protocols implemented by SoCalGas and SDG&E as a result of a 2016 settlement as examples of how PG&E could implement curtailment.⁹⁴⁸ However, the SoCalGas/SDG&E settlement referenced by SCGC/Palo Alto appears to address the order in which curtailments occur and the amount of curtailment.⁹⁴⁹ PG&E's concerns regarding curtailment are not about which customers get curtailed first and by

⁹⁴⁵ SCGC/PA-01-E, p. 4, line 21 to p. 7, line 5.

⁹⁴⁶ PG&E-16-E, p. 7B-5, lines 3-6.

⁹⁴⁷ PG&E-16-E, p. 7B-5, lines 8-12.

⁹⁴⁸ SCGC/PA-01-E, p. 7, line 6 to p. 8, line 12; TURN-21, p. 6, lines 18-24.

⁹⁴⁹ SCGC/PA-01-E, p. 8, lines 5-12.

how much. Rather, our concern is about the effectiveness and impact of potentially large and widespread curtailments with little or no notice.

Moreover, the SoCalGas and SDG&E curtailment protocols have led to significant supply issues and price spikes in Southern California. The Commission recently issued an Order Instituting Rulemaking (R.) 20-01-007 which described some of the curtailment challenges associated with SoCalGas' curtailment during cold weather in 2018. The Commission noted that SoCalGas' curtailments adversely impacted electric generators and potentially caused reliability, operational, and market price issues.⁹⁵⁰ Indeed, SCGC itself stated in comments in R.20-01-007:

The date of the Curtailment Procedures Settlement Agreement was April 28, 2016. . . . Curtailments seemed to be a thing of the past at the time of the settlement. Consequently, the provision eliminating the Service Interruption Credit received little attention in the decision. In fact, and Commission did not even mention it in the text of D.16-07-008.

Curtailments and price spikes returned with a vengeance for SoCalGas customers after October 1, 2017 explosion ⁹⁵¹

Thus, the very SoCalGas/SDG&E settlement that SCGC/Palo Alto and TURN now put forward as a model for curtailment was clearly a matter of concern to SCGC because, when pipelines were put out of service (i.e., an unplanned outage), “curtailments and price spikes returned with a vengeance.” PG&E is surprised that having experienced the impact of SoCalGas curtailments and price spikes, SCGC is now willing to propose that PG&E adopt the same curtailment procedures used by SoCalGas.

Finally, relying on the SoCalGas and SDG&E curtailment protocols, SCGC/Palo Alto and TURN assert that PG&E could curtail electric generation and other large customers first, and thus would not have to curtail core customers.⁹⁵² SCGC/Palo Alto argue that PG&E's 30

⁹⁵⁰ *Order Instituting Rulemaking*, R.20-01-007 (Jan. 27, 2020), pp. 8-10.

⁹⁵¹ PG&E-16-E, p. 7B-6, lines 15-24 (emphasis added) (quoting SCGC comments).

⁹⁵² SCGC/PA-01-E, p. 8, line 13 to p. 9, line 8; TURN-21, p. 6, lines 18-24.

largest customers have sufficient demand such that, if they were curtailed, this amount of curtailment would eliminate the need for Reserve Capacity.⁹⁵³ As a preliminary matter, both SCGC/Palo Alto candidly admitted in discovery that they did not consult with any electric generation or large industrial customers in making these recommendations.⁹⁵⁴ These customers may strongly oppose their facilities being curtailed first. In addition, curtailments of large industrial customers, such as refineries, would likely be ineffective. As PG&E witness Graham explained, curtailment of customers as SCGC/Palo Alto and TURN propose could have serious detrimental impacts:

The oil refineries represent a significant portion of the gas load of the 30 largest noncore customers. Gas curtailments to the oil refineries with little or no notice is unlikely to be successful. While the refineries can quickly substitute some internal fuel streams for natural gas, this would only represent a small percentage of their total use. Beyond the limited fuel substitution, the refineries would need to shut down selected refining units which take time to do in an orderly way. A quick or emergency shut down of a refining unit within a large refinery can cause significant disruptions to other units and potentially the shutdown of a large portion of the whole refinery. It can take days or weeks to restore a refinery to full capacity after such a significant event.⁹⁵⁵

In short, PG&E demonstrated in its opening and rebuttal testimony that hourly curtailment is not an adequate substitute for Reserve Capacity, and SCGC/Palo Alto and TURN have failed to offer any convincing evidence to effectively rebut this testimony.

3.6.3.3 Hourly Curtailments Do Not Justify Eliminating Los Medanos

Based on the argument that hourly curtailments can replace Reserve Capacity, SCGC/Palo Alto and TURN then argue that eliminating Reserve Capacity would essentially reduce the capacity shortfall identified by PG&E in its Peak Day Supply Standard analysis.⁹⁵⁶ There are several problems with this argument.

⁹⁵³ SCGC/PA-01-E, p. 9, lines 3-8; see also TURN-21, p. 6, lines 3-8 (citing SCGC/Palo Alto).

⁹⁵⁴ PG&E-36, SCGC/Palo Alto response to PG&E_SCGC-PA003-Q05; PG&E-49, TURN response to PGE_TURN020-Q04.

⁹⁵⁵ PG&E-16-E, p. 7B-7, lines 5-16.

⁹⁵⁶ TURN-21, p. 7, lines 1-12; SCGC/PA-01-E, p. 10, lines 1-10.

First, even if the Reserve Capacity requirement is eliminated as a result of curtailment, this does not fully address the capacity shortfall identified by PG&E during the rate case period.⁹⁵⁷

Second, there is a timing issue. TURN and SCGC acknowledge that a curtailment protocol would need to be negotiated and then presented to the Commission for approval.⁹⁵⁸ This process could take several years after a decision is issued in this proceeding. Once approved, the curtailment protocol would need to be implemented. However, the capacity needs identified by PG&E occur at the very beginning of the rate case period and continue to grow throughout that period.⁹⁵⁹

Even TURN and SCGC/Palo Alto acknowledge that Los Medanos cannot and should not be retired until the Commission approves a curtailment protocol and this protocol can then be implemented. As SCGC/Palo Alto explained in discovery:

While SCGC/PA are confident that a curtailment plan can substitute for the capacity provided by Los Medanos, SCGC/PA are not recommending that Los Medanos be sole or decommissioned until a curtailment plan is approved by the Commission and implemented by PG&E.⁹⁶⁰

Thus, the proposal put forward by SCGC/Palo Alto and TURN does not address the issue of retaining Los Medanos starting in 2023 and through the rate case period until a curtailment protocol could be approved and implemented as directed by the Commission. Moreover, the capital improvements needed at Los Medanos, such as replacing an obsolete compressor and upgrading control systems, are either pressing and cannot be delayed or, in the case of well

⁹⁵⁷ SCGC/PA-01-E, p. 10, lines 5-6.

⁹⁵⁸ PG&E-36, SCGC/Palo Alto response to PG&E_SCGC-PA003-Q06; PG&E-49, TURN response to PGE_TURN020-Q16(a).

⁹⁵⁹ PG&E-03, p. 7-48, Table 7-15, line 18.

⁹⁶⁰ PG&E-36, SCGC/Palo Alto response to PG&E_SCGC-PA003-Q09.

reworks and retrofits, the timing is driven by regulatory requirements and mandated deadlines.⁹⁶¹

Finally, it is notable that SCGC/Palo Alto appears to hedge as to whether implementing curtailed and eliminating Reserve Capacity Service would eliminate the need for Los Medanos. SCGC/Palo Alto state that if PG&E implements curtailment it “may be able to entirely avoid the need to restore Los Medanos . . .”⁹⁶² Thus, SCGC/Palo Alto would have the Commission direct PG&E to develop and implement a curtailment program that could significantly disrupt noncore customers such as electric generation and industrial customers but does not guarantee that doing so would result in the elimination of other needed capacity investments.

3.6.4 Retention of Los Medanos, Drilling New Wells and Cross Compression

Upon identifying a need for gas capacity shortfall in the Peak Day Supply Standard analysis, PG&E considered three separate alternative to addressing this shortfall.⁹⁶³ After a comprehensive analysis, PG&E determined that the most cost-effective approach involved three elements: (1) retaining Los Medanos; (2) drilling three new wells at McDonald Island and three new wells at Gill Ranch; and (3) installing cross-compression equipment. No party disputes that among the three alternatives presented by PG&E, retaining Los Medanos, drilling new wells, and installing cross-compression is the most cost effective option as compared to the other alternatives considered by PG&E.

Instead, parties maintain that Los Medanos does not need to be retained based on several different arguments. TURN and SCGC/Palo Alto argue that Los Medanos can be sold or decommissioned after PG&E implements a curtailment protocol. This argument is addressed above in Section 3.6.3. While TURN also opposes the drilling of new wells and cross-

⁹⁶¹ PG&E-03, p. 6-32, lines 6-21 (describing the need to replace a gas compressor at Los Medanos); p. 7-42, lines 6-24 (describing need for well control upgrades at Los Medanos).

⁹⁶² SCGC/PA-01-E, p. 10, line 8 (emphasis added).

⁹⁶³ PG&E-03, p. 7-52, line 21 to p. 7-54, line 3.

compression,⁹⁶⁴ SCGC/Palo Alto does not oppose the drilling of new wells or cross-compression because SCGC/Palo Alto recognize that curtailment is not sufficient to address the capacity shortfall.⁹⁶⁵

Wild Goose, LGS and TURN maintain that Independent Storage Providers or “ISPs” can address any curtailment shortfall and thus argue that Los Medanos is not needed. These parties also raise several additional issues that are classic red herrings. All of these issues are addressed below. In addition, in this Section 3.6.4, PG&E explains why regulatorily mandated work at Los Medanos is time sensitive and the Commission ought to approve the retention of Los Medanos and the performance of this work during the rate case period.

3.6.4.1 The Retention of Los Medanos, Drilling New Wells, And Cross-Compression Are Necessary

PG&E’s proposal to retain Los Medanos, drill new wells at McDonald Island and Gill Ranch, and install cross-compression is based on the Peak Day Supply Standard analysis described above in Section 3.6.2. PG&E has demonstrated that this analysis is reasonable and that, based on the capacity shortfall forecasted, these three actions are reasonable and necessary.⁹⁶⁶

TURN and SCGC/Palo Alto argue that curtailment may be an alternative to retaining Los Medanos. Their curtailment arguments are addressed above in Section 3.6.3. Wild Goose and LGS argue (and TURN argues in the alternative) that ISP capacity is a reasonable substitute for Los Medanos. This issue is addressed below in Section 3.6.4.2. TURN is the only party that directly addresses the proposal for new drilling at McDonald Island and Gill Ranch.⁹⁶⁷ Arguments regarding drilling new wells are addressed below in Section 3.6.5. TURN is also the

⁹⁶⁴ TURN-07, p. 20, line 2 to p. 21, line 7.

⁹⁶⁵ PG&E-36, SCGC/Palo Alto response to PG&E_SCGC-PA004-Q01(a).

⁹⁶⁶ PG&E-03, p. 7-52, line 18 to p. 7-54, line 12.

⁹⁶⁷ TURN-07, p. 20, lines 21-23.

only party that addresses cross-compression. However, TURN simply proposes no new cross-compression is needed based on its peak day forecast.⁹⁶⁸ TURN acknowledges that “[c]ross-compression is by far the cheapest alternative”⁹⁶⁹ but does not believe it is needed based on its revised peak day forecast. Arguments regarding the Peak Day Supply Standard are addressed above in Section 3.6.2.

PG&E witness Lucy Redmond explained that in addition to the application of the Peak Day Standard, it is also important to retain Los Medanos due to CalGEM regulations regarding well reinspections, reworks, and retrofits. To perform a reinspection, rework or retrofit, a gas storage well must be taken out of service as described in PG&E’s opening testimony.⁹⁷⁰ When a well is out of service as a result of a reinspection, rework or retrofit, this reduces the amount of natural gas that can be withdrawn from or injected into the storage field. The fewer wells in service, the less natural gas that is available for withdrawal or injection.

Ms. Redmond explained the critical necessity of retaining Los Medanos to address the loss of capacity associated with well reinspections, reworks and retrofits:

So as we look at the impact to outage as we perform inspections, what we see is a fairly significant hit based upon the number of wells that we have to rework or inspect in a given calendar year. So typically, we perform the rework activities from March to November. Granted, these are very closely-spaced facilities, and that work has to be very well orchestrated and staged to get through the book of work in the timeline available.

Following the completion of that work, we have to -- we rely on a cleanup cycle to maintain reservoir and well integrity which requires those wells to subsequently be out of service through the winter period until they are brought back on an official capacity.

So as we increase the number of wells that were required to rework in a given year, the impact to the outage is subsequently further impacted, and so retention

⁹⁶⁸ TURN-07, p. 20, line 1 to p. 21, line 7.

⁹⁶⁹ TURN-07, p. 20, lines 3-4.

⁹⁷⁰ PG&E-03, p. 7-24, line 8 to p. 7-25, line 12.

of Los Medanos was necessary to continue to meet our demand requirements through the last several years and looking forward.⁹⁷¹

Ms. Redmond also explained at the hearing that retaining Los Medanos is critical given the uncertainty of CalGEM's inspection cycle:

Q So whether the inspection interval is five-to-eight years or the two years, which I think is current proposed -- or is the current regulation or proposed regulation, what would PG&E have to do differently with regard to Los Medanos?

A So if the requirement was to inspect wells prescriptively at a 24-month interval, it would be extremely difficult for us to continue to provide a storage service. What we've proposed is, again, well-by-well based on conditions, a return frequency that aligns with that condition identified. Majority of our wells fall in the 8-to-12 year cycle or 12-to-15.

Q Well, what if you don't -- what if your petition is not granted, then what will PG&E's plan be with regard to Los Medanos?

A If it's not granted, we would need it even more severely. I think depending on the outcome of CalGEM's decision, we would have to have them continue to have very serious discussions with CalGEM and the other stakeholders about the implications to our ability to serve with the - a -- a high frequency return rate that's prescriptively applied.⁹⁷²

None of the parties have offered any evidence that, given the uncertainty of CalGEM regulations and requirements, retaining Los Medanos is unnecessary. Instead, these parties simply assume away any uncertainty. However, as Ms. Redmond explained at hearing, these uncertainties are significant and further demonstrate the substantial need to retain Los Medanos. The retention of Los Medanos is not only supported by the Peak Day Supply Standard; it is also supported by the need to address uncertain CalGEM rules and regulations, which other parties essentially ignore.

Finally, the regulatory uncertainty that is in Ms. Redmond's undisputed testimony is the exact reason why the Commission decided in the 2019 GT&S rate case that the retention of Los Medanos was still an open issue. In that proceeding, the Commission noted:

⁹⁷¹ Tr. Vol. 6, 1011:4 to 1012:1, PG&E/Redmond.

⁹⁷² Tr. Vol. 6, 1012:21 – 1013:19, PG&E/Redmond.

However, we find that PG&E's estimate of the amount of withdrawal and injection capacity that McDonald Island will provide after PG&E begins complying with the [CalGEM] May 19 Rule could be inaccurate given the uncertainty associated with the expansive scope of the retrofit and investigation activities required to comply with the [CalGEM] May 19 Rule. Unlike the Joint IPSs' storage fields, including Gill Ranch, PG&E's Los Medanos and McDonald Island storage fields are located within upstream and downstream pipeline constraints. Thus, if the actual loss in withdrawal and injection capacity at McDonald Island is substantially higher than 40 percent, PG&E's ability to provide reliable gas transmission service could be compromised.

Accordingly, to decommission Los Medanos, PG&E must file a Tier 2 Advice Letter on or after December 31, 2021, demonstrating that it has the requisite storage capacity to operate without the Los Medanos storage field. Until the PG&E's Tier 2 Advice Letter is approved, PG&E is not permitted to remove more than half of the working gas at Los Medanos or sell or begin decommissioning activities at Los Medanos.⁹⁷³

PG&E's operations have been and will continue to be impacted by CalGEM regulations, which, in part, forms the basis for the need to retain Los Medanos. In the 2019 GT&S rate case the Commission was cognizant of the need not to "compromise" gas transmission service by prematurely shutting down Los Medanos. The Commission should take the same approach here where there is even greater evidence of a potential risk to gas supply if Los Medanos is not retained.

3.6.4.2 ISP Capacity Is Not A Reasonable Substitute for Los Medanos

As an alternative to retaining Los Medanos, Wild Goose, LGS, and TURN assert that ISPs can provide sufficient capacity to meet any shortfall and that PG&E should simply buy an ISP facility or contract with an ISP for capacity.⁹⁷⁴ There are several fundamental problems with this proposal.

First, the ISP capacity identified by Wild Goose and LGS cannot meet PG&E's customer demands because of the Redwood Path constraint. The Redwood Path constraint is a physical limitation on the amount of natural gas that can be delivered from ISP facilities to reach

⁹⁷³ D.19-09-025, pp. 71-72.

⁹⁷⁴ WGL-02, p. 6, line 10 to p. 7, line 6; TURN-21, p. 8, line 16 to p. 11, line 4.

customers in the Bay Area, where there is substantial gas demand.⁹⁷⁵ The Commission recognized the existence of this constraint in the 2019 GT&S rate case decision determining that there was a constraint on the Redwood and Baja Paths and indicated that no party contested the fact that these constraints exist.⁹⁷⁶ Wild Goose and LGS argue that the Redwood Path constraint does not impact deliveries of ISP storage, but they offer no analysis which would support this assertion or undercut the Commission's earlier determination.⁹⁷⁷ The existence of the Redwood Path constraint is important because the arguments made by Wild Goose and LGS hinge on the assumption that northern ISP storage is interchangeable with PG&E's Los Medanos facility and that the ISPs are able to provide additional capacity if needed.⁹⁷⁸ This is simply not true. Los Medanos is located downstream of the Redwood Path constraint and thus the Los Medanos facility can provide services that the ISPs cannot provide because they are limited by the Redwood Path constraint.⁹⁷⁹

In its rebuttal testimony, TURN also questions the Redwood Path constraint.⁹⁸⁰ This is quite surprising given that in the 2019 GT&S rate case, TURN's witness Michel Florio, who appeared in both cases, stated quite strongly that he had been presented with information which convinced him as to the validity of the Redwood Path constraint.⁹⁸¹ While Mr. Florio tried at the hearing to backtrack on his unequivocal testimony from the 2019 GT&S rate case, Mr. Florio

⁹⁷⁵ PG&E-16-E, p. 7B-18, lines 16-26 and p. 7B-19, Figure 7B-1.

⁹⁷⁶ D.19-09-025, pp. 71, 78.

⁹⁷⁷ WGL-01, p. 6, lines 6-19.

⁹⁷⁸ See e.g., WGL-01, p. 5, lines 8-20.

⁹⁷⁹ PG&E-16-E, p. 7B-20, lines 7-13; see also D.19-09-025, p. 71 (stating that Los Medanos is downstream of constraints).

⁹⁸⁰ TURN-21, p. 10, lines 11-14.

⁹⁸¹ PG&E-50, p. 8, lines 12-15.

conceded that his 2019 testimony was true and correct when submitted.⁹⁸² In this proceeding, Mr. Florio did not provide any evidence which would justify changing his mind regarding the Redwood Path constraint. Moreover, his testimony in this proceeding is completely equivocal, all that he states is that he has questioned PG&E about the Redwood Path constraint and that it is “murky at best.”⁹⁸³ Other than rhetoric, Mr. Florio provides no evidence that the Redwood Path constraint does not exist.

Second, Wild Goose and LGS argue that they can deliver more gas under certain conditions despite the Redwood Path constraint.⁹⁸⁴ The Redwood Path constraint applies to almost all combinations of gas coming from the California-Oregon border and northern ISP withdrawals. Wild Goose and LGS are correct that during cold peak day events the market supplies less gas from the California-Oregon Border and thus the ISPs can provide more deliveries than identified in PG&E's updated Peak Day Supply Standard analysis. However, the total deliveries from any source north of the Redwood Constraint still cannot be more than 2,700 mmcf/d.⁹⁸⁵ The Redwood Path constraint is a physical limitation that the ISPs cannot overcome simply because they want to provide more storage services.

Third, while Wild Goose and LGS argue that PG&E should contract for ISP capacity or, alternatively, purchase an ISP storage field, in discovery they refused to provide critical data concerning their facilities' actual operations.⁹⁸⁶ Thus, there is no evidence to determine whether the ISPs have sufficient capacity on a peak day to meet needed demand. PG&E witness Roger Graham explained that Wild Goose and LGS have been “extremely secretive” about providing

⁹⁸² Tr. Vol. 13, 2487:13-17, TURN/Florio.

⁹⁸³ TURN-21, p. 10, lines 12-14.

⁹⁸⁴ WGL-01, p. 10, line 8 to p. 11, line 8.

⁹⁸⁵ PG&E-16-E, p. 7B-20, line 23 to 7B-21, line 3.

⁹⁸⁶ PG&E-35 (data responses where Wild Goose and LGS refused to provide operating data).

information regarding their facilities.⁹⁸⁷ Even if the Redwood Path constraint did not exist, which it does, there is insufficient evidence to conclude that the Wild Goose and Lodi facilities have sufficient capacity to address the capacity shortfall identified by PG&E.

Fourth, as Wild Goose and LGS concede, purchasing their facilities or contracting for capacity would not solve the capacity shortfall. These parties candidly admit that “[i]f PG&E were to purchase an ISP’s facilities, there would be no net increase in available capacity in the natural gas market.”⁹⁸⁸

Finally, perhaps sensing that the ISP facilities as currently configured are not a viable option for replacing Los Medanos given the Redwood Path constraint, TURN posits that there *may* be ways to connect these facilities further downstream on PG&E’s pipeline system to avoid the constraint.⁹⁸⁹ However, TURN offers no specifics and this proposal, to evaluate other possible interconnections for the ISP facilities, could take years and stretch well into the next GRC. During that time, PG&E would still need to operate and maintain Los Medanos. Moreover, there are numerous factors to consider and even connecting these facilities further downstream may not solve the problem.⁹⁹⁰ The Commission cannot and should not delay needed work at Los Medanos in the hope that ISP facilities may be able to provide needed capacity at some unknown point in the future.

3.6.4.3 Wild Goose and LGS Raises Issues That Are Red Herrings

Wild Goose and LGS also include in their testimony several red herrings that can be readily addressed. First, they speculate that PG&E will “undercut” ISP prices in an anti-competitive manner by using park and lend pricing.⁹⁹¹ The price quotes in Wild Goose’s and

⁹⁸⁷ Tr. Vol. 6, 984:10, PG&E/Graham.

⁹⁸⁸ WGL-02, p. 7, lines 9-10.

⁹⁸⁹ TURN-21, p. 10, line 15 to p. 11, line 4.

⁹⁹⁰ Tr. Vol. 6, p. 984:1-985:1, PG&E/Graham.

⁹⁹¹ WGL-02, p. 4, lines 5-17.

LGS’ testimony for park and lend services are a minimum price that has been in place for years. Wild Goose and LGS provide no evidence that PG&E has ever used this minimum price for park and lend in an anti-competitive manner or would do so in the future. More importantly, PG&E’s park and lend prices are approved by the Commission.⁹⁹² If Wild Goose and LGS believe these prices are anti-competitive, they should pursue that issue at the Commission; these approved prices do not justify shutting down Los Medanos.

Second, Wild Goose and LGS assert that allowing PG&E to make “ratepayer-funded capacity additions and below market pricing could risk undermining the viability of ISPs.”⁹⁹³ However, pronouncements by Rockpoint Gas Storage (the owner of Wild Goose and LGS) indicate that both entities are quite viable.⁹⁹⁴ On its website, Rockpoint Gas Services states:

Rockpoint Gas Storage is owned by Brookfield Infrastructure Fund II and Brookfield Americas Infrastructure Fund, both of which are managed by Brookfield Asset Management (Brookfield). Brookfield is a leading alternative asset manager with over \$575 billion in long-life, high-quality assets and businesses in more than 30 countries around the world. Rockpoint manages and operates Brookfield’s natural gas storage asset portfolio.⁹⁹⁵

Third, Wild Goose, LGS, and TURN argue that PG&E should not be able to “undercut ISP storage through ratepayer-funded capacity additions. . .”⁹⁹⁶ PG&E’s proposed retention of Los Medanos is not intended to “undercut” ISP storage. ISP storage can and will continue to exist on PG&E’s system. Instead, retaining Los Medanos is necessary to meet a capacity shortfall that cannot be met by ISP storage.

⁹⁹² PG&E-16-E, p. 7B-17, lines 1-8. TURN cites to Wild Goose and LGS’ statements on pricing but offers no evidence of its own. See TURN-21, p. 8, lines 11-15.

⁹⁹³ WGL-02, p. 5, lines 3-5.

⁹⁹⁴ PG&E-16-E, lines 13-15.

⁹⁹⁵ PG&E-16-E, p. 7B-17, lines 15-23.

⁹⁹⁶ WGL-02, p. 5, lines 3-5; TURN-21, p. 8, lines 11-13.

Fourth, Wild Goose and LGS assert that PG&E's costs to drill new wells and convert existing wells to tubing and packer are high compared to their own costs.⁹⁹⁷ There are likely a number of reasons for cost differences, but the fact that there are different costs does not mean that PG&E's drilling and conversion costs are unreasonable. Rather, there may be a number of reasons why costs can differ and both sets of costs can be reasonable and prudent.⁹⁹⁸ Other than referring to PG&E's costs as "inflated", Wild Goose and LGS offer no evidence that based on the conditions at PG&E's gas storage fields, PG&E's costs are unreasonable.⁹⁹⁹

Finally, Wild Goose and LGS argue that the capacity additions proposed by PG&E are "front-loaded" because there is additional capacity in the earlier years of the rate case period and capacity shortfalls in the later years.¹⁰⁰⁰ However, given the nature of project timing, there will never be a perfect match between capacity becoming available and the capacity need being addressed. There is always likely to be a difference between the two, either additional capacity or a capacity shortfall. PG&E's proposal is prudent and reasonable because it provides for capacity being available when it is needed. The alternative would be to delay projects and to hope the capacity is not needed during the delay period. This approach threatens reliability, which is critical for a gas storage system.¹⁰⁰¹ Moreover, Wild Goose and LGS' arguments that PG&E is "front-loading" capital additions are, at best, overstated. As PG&E explained:

PG&E also notes that the capacity additions in 2024-2025 will approximately equal the capacity shortfall during the same time and that in 2025-2026 and 2026-2027 the capacity additions will be less than the capacity shortfall. In other words, for 75% of the rate case period (i.e., 2023-2026), PG&E's proposed capacity additions will be approximately equal to or less than the capacity shortfall. PG&E indicated in testimony that it would continue to explore options

⁹⁹⁷ WGL-01, p. 12, line 1 to p. 13, line 4.

⁹⁹⁸ PG&E-16-E, p. 7A-9, line 2 to p. 7A-10, line 7.

⁹⁹⁹ PG&E-16-E, p. 7A-10, lines 8-17.

¹⁰⁰⁰ WGL-01, p. 11, lines 9-21.

¹⁰⁰¹ PG&E-16-E, p. 7B-21, line 24 to p. 7B-22, line 3.

for years in which the capacity shortfall exceeds the amount of the capacity additions.¹⁰⁰²

3.6.4.4 Work at Los Medanos Is Critical and Time Sensitive

One of the issues that parties fail to grapple with is the time sensitive nature of work needed at Los Medanos. TURN and SCGC/Palo Alto advocate curtailment as an alternative but concede that curtailment protocols would need to be prepared and approved by the Commission, which is likely to be a lengthy process.¹⁰⁰³ Wild Goose, LGS, and TURN argue that PG&E could contract for ISP capacity or purchase an ISP facility. This process is also quite lengthy including time to conduct negotiations and obtain Commission approval of a purchase or contract transaction.¹⁰⁰⁴

PG&E can ill afford the lengthy procedural delays proposed by these parties. Wells at Los Medanos need to be re-worked and retrofitted in 2023 and 2024 to comply with CalGEM regulations:

- Q Okay. And you indicated in response to some of Judge Larsen's questions that there would be four well baseline conversions in 2023 at Los Medanos; is that correct?
- A Our current arrangement with CalGEM's forecast completing four of these inspections and conversions in '23 and additional four wells in '24.
- Q Okay. And with regard to the four conversions, for example, in 2023, that's not optional, is it? It's not like PG&E can say we don't want to do it this year, we'll do some other year? That's a requirement, isn't it?
- A That is correct. We, again, interfaced with CalGEM regarding that 24-month requirement and our concern for winter deliverability should that be stipulated, and we've arrived at the determination letter from CalGEM that requires us to complete the scope of work as indicated in that schedule.

1002 WGL-01, Attachment E.

1003 PG&E-36, SCGC/Palo Alto response to PG&E_SCGC-PA003-Q06; PG&E-49, TURN response to PGE_TURN020-Q16(a).

1004 PG&E-49, TURN response to PGE_TURN020-05(c) (acknowledging that purchasing an ISP facility would require Commission approval).

Q Okay. And that would also be true for the 2024 baseline conversions, that it's requirement from CalGEM and not an option for PG&E?

A That is correct.¹⁰⁰⁵

PG&E cannot simply wait for a decision in this proceeding and hoped for solutions without specifics or details that have been offered by the parties. At a minimum, the Commission should approve the retention of Los Medanos during this rate case period and authorize the work necessary to comply with CalGEM regulations in a timely manner.

3.6.5 Well Drilling – Capital (MAT 3L1)

Drilling new wells at existing storage facilities is critical to ensure that the natural gas can be injected into or withdrawn from storage facilities when needed. New wells are especially critical because CalGEM regulations regarding retrofits and re-works, as well as more frequent inspection cycles, can result in existing wells being taken out of service frequently and for extended periods of time.¹⁰⁰⁶ In addition, the tubing and packer configuration required by CalGEM regulations reduces well capacity. Thus, as PG&E explained “[t]he number of wells out of service during peak demand period [as a result of re-works or inspections] coupled with reduced well capacity via installation of dual barriers requires that additional wells be installed to offset the capacity loss.”¹⁰⁰⁷

To address these issues, PG&E proposes drilling 12 new wells during the rate case period.¹⁰⁰⁸ Three (3) of these 12 new wells would be at the McDonald Island facility to address the capacity shortage forecasted in our Peak Day Supply Standard analysis (discussed in Section 3.6.2 above). The remaining 9 wells would also be drilled at McDonald Island to provide needed withdrawal capacity at that facility given the impact reinspection frequency and reworks/retrofits

¹⁰⁰⁵ Tr. Vol. 6, 1025:9 to 1026:8, PG&E/Redmond (a baseline conversion refers to a re-work and retrofit).

¹⁰⁰⁶ PG&E-03, p. 7-39, line 15 to p. 7-40, line 2.

¹⁰⁰⁷ PG&E-03, p. 7-39, line 22 to p.7-40, line 2.

¹⁰⁰⁸ PG&E-03, p. 7-41, Table 7-12.

have on existing well capacity. Our opening testimony and workpapers describe PG&E’s new drilling proposal in detail and provide evidence demonstrating that the program and PG&E’s cost forecast for the rate case period are prudent and reasonable.¹⁰⁰⁹ TURN is the only party to dispute PG&E’s capital expenditure forecast for well drilling and proposes that no new wells be drilled as summarized in Table 3-39 below:

TABLE 3-39
WELL DRILLING (MAT 3L1): PG&E’S CAPITAL FORECAST AND PARTIES
RECOMMENDED REDUCTIONS (\$000s)^(a)

Party	2020 Rec.	2021	2022	2023	2024	2025	2026
PG&E	\$--	\$4,980	\$--	\$18,886	\$45,884	\$32,973	\$--
TURN				\$(18,886)	\$(45,884)	\$(32,973)	

(a) PG&E-16-E, p. 7A-35, Table 7A-9, line 2 (PG&E’s 2020-2022 recorded and forecast costs); PG&E-3-ES, p. v (PG&E’s 2023-2026 forecast); TURN-21, p. 14 and PG&E-64, p. JCE 3-59 (TURN’s recommendation).

TURN argues that drilling 3 new wells proposed for McDonald Island based on the updated Peak Day Supply Standard analysis is not reasonable.¹⁰¹⁰ However, as explained in detail above in Section 3.6.2, PG&E’s updated Peak Day Supply Standard analysis is well founded and based on reasonable data and assumptions. Because the Peak Day Supply Standard is reasonable, the proposal to drill three new wells at McDonald Island to meet the forecasted capacity shortfall identified in that analysis should be approved. TURN acknowledges that the analysis supporting the alternative to retain Los Medanos, install cross-compression, and drill three new wells at McDonald Island was “reasonable”, even if TURN disagrees with the underlying premise (*i.e.*, the Peak Day Supply Standard).¹⁰¹¹

With regard to the remaining 9 wells, PG&E has indicated these will be necessary to address CalGEM’s requirements for: (1) rework and retrofit of existing wells to tubing and packer, which results in wells being out of service during the conversation process, as well as

¹⁰⁰⁹ PG&E-03, p. 7-39, line 13 to p. 7-42, line 2; PG&E-3-ES, WP 7-28; PG&E-03, WP 7-34.

¹⁰¹⁰ TURN-07, p. 20, lines 21-23.

¹⁰¹¹ TURN-07, p. 17, lines 14-15.

CALGEM’s proposed inspection cycles; (2) loss of capacity for wells taken out of service due to a failed pressure test; and (3) continued expected well obsolescence due to frequent intervention or identified well integrity issue. To make up for this lost capacity during reinspections, reworks and retrofits, and reduced capacity from wells after tubing and packer is completed, PG&E is proposing to drill 9 additional wells at McDonald Island. TURN does not oppose PG&E’s unit cost forecast for new wells but indicates that PG&E’s tubing and packer conversion has not “resulted in an additional need for nine new wells in 2024-2025” and thus argues that the nine new wells are not needed.¹⁰¹²

However, as explained in PG&E’s opening testimony and above in Section 3.6.4.1, CalGEM’s regulations for both well reworks/retrofits and inspection cycles will have a significant impact on existing well capacity. There continues to be uncertainty in the storage capacity that will be available due to pending reinspection interval for wells and loss of existing wells.¹⁰¹³ As PG&E explained in rebuttal testimony, its Peak Day Supply Standard analysis did not consider the impact of CalGEM reinspection cycles and thus likely understates the need for new wells.¹⁰¹⁴ TURN’s proposal that no new wells be drilled during the rate case period will inevitably lead to supply shortages as a result of existing wells being unavailable due to required tubing and packer conversion or a required reinspection.

Finally, in rebuttal testimony, PG&E provided an analysis of the impact of PHMSA and CalGEM inspection regulations on the need to drill new wells. PG&E’s analysis demonstrates that more frequent inspections, which will likely be required under CalGEM regulations, will accelerate the need for new drilling as inspection frequency degrades well capacity. PG&E’s analysis is based on actual data from inspections that have occurred to date and PHMSA

¹⁰¹² TURN-07, p. 33, lines 1-10.

¹⁰¹³ PG&E-03, p. 7-41, line 11 to p. 7-42, line 2; PG&E-16-E, p. 7A-31, lines 8-10.

¹⁰¹⁴ PG&E-16-E, p. 7A-31, lines 16-19.

research.¹⁰¹⁵ Given the potential impact of mandated reinspections, PG&E’s forecast for new well drilling is entirely reasonable.

3.6.6 Well Reworks/Retrofits – Capital (MAT 3L3)

This scope of work for the Reworks and Retrofits Program includes retrofit, repair, or assessment of the storage well to: (1) mitigate a single point of failure (i.e., installation of dual barrier); (2) assess the condition of a well; and/or (3) perform corrective work. This work primarily relates to retrofit/conversion of wells from their existing condition of tubing and packer to dual barrier construction consistent with the CalGEM requirements and regulations but can also involve reworking a well that is impacted by activities such as pressure testing. MAT 3L3 includes the capital work associated with this conversion and inspection activity.¹⁰¹⁶ For ease of reference in this section, PG&E will refer to “reworks and retrofits” as “reworks.”

PG&E is forecasting that it will perform 56 reworks during the rate case period. Forty (40) of these reworks will be associated with wells that are scheduled to be converted to tubing and packer. The remaining 16 reworks are associated with emergent work.¹⁰¹⁷ Emergent work on a well is work identified during the course of routine monitoring, surveillance, and/or testing as needing a rig to be brought in for further investigation and/or mitigation. PG&E provided a detailed list of the circumstances that may cause emergent work.¹⁰¹⁸ Our opening testimony and workpapers describe this program and provide evidence demonstrating that the program and PG&E’s cost forecast for the rate case period are prudent and reasonable.¹⁰¹⁹

¹⁰¹⁵ PG&E-16-E, p. 7A-27, line 4 to p. 7A-28, line 22.

¹⁰¹⁶ PG&E-16-E, p. 7A-11, lines 13-20.

¹⁰¹⁷ PG&E-16-E, p. 7A-12, Table 7A-5.

¹⁰¹⁸ PG&E-16-E, p. 7A-12, line 1 to p. 7A-13, line 2.

¹⁰¹⁹ PG&E-03, p. 7-27, line 6 to p. 7-30, line 26; PG&E-3-ES, WP 7-29 to WP 7-32; PG&E-03, WP-36.

TURN is the only party that addresses this program and proposes the following reduction:

TABLE 3-40
WELL REWORKS (MAT 3L3): PG&E’S CAPITAL FORECAST AND PARTIES
RECOMMENDED REDUCTIONS (\$000s)^(a)

Party	2020 Rec.	2021	2022	2023	2024	2025	2026
PG&E	\$50,407	\$60,560	\$64,735	\$85,199	\$82,623	\$14,509	\$18,553
TURN				\$(22,148)	\$(25,732)	\$(7,792)	\$(11,684)

(a) PG&E-16-E, p. 7A-35, Table 7A-9, line 1 (PG&E’s 2020-2022 recorded and forecast costs); PG&E-3-ES, p. v (PG&E’s forecast 2023-2026); TURN-21, p. 14 and PG&E-64, p. JCE 3-59 (TURN’s recommendation).

TURN proposes reducing PG&E’s forecast from 56 reworks to 40 reworks based on its argument that: (1) the emergent work forecast should be reduced from 16 to 8; and (2) reworks are unnecessary at Los Medanos given TURN’s recommendation that the facility be sold or decommissioned.¹⁰²⁰ TURN also proposes reducing the unit cost of reworks. These recommendations are addressed below.

3.6.6.1 The Number of Reworks Forecast Should Not Be Reduced

TURN proposes reducing the rework forecast by 16 based on its arguments regarding the need for Los Medanos and emergent work. The need for Los Medanos is addressed above in Section 3.6.4. TURN does not dispute the need for reworks at the facility if continued operation of Los Medanos is required.

TURN contends that the number of emergent units in PG&E’s forecast exceeds what will realistically materialize and recommends only eight emergent wells (two per year over the 4-year rate case cycle (2023-2026)) be adopted.¹⁰²¹ TURN mistakenly argues that wells that were recently reworked should not necessitate additional emergent work “[i]f the original work was

¹⁰²⁰ TURN-07, p. 27, lines 8-9; TURN-21, p. 12, lines 8-11 (reducing TURN’s proposal to 40 reworks).

¹⁰²¹ TURN-07, p. 26, line 23 to p. 27, line 2.

performed competently...”¹⁰²² TURN misunderstands PG&E’s testimony. The basis for increasing the occurrence of emergent work units in PG&E’s testimony was tied directly to the increase in pressure testing that is required under CalGEM’s Determination Letter dated June 15, 2021 (June 15 determination).¹⁰²³ The June 15 determination establishes the frequency and requirements related to pressure testing. CalGEM’s June 15 determination required pressure testing every two years. As a result of CalGEM’s requirements, PG&E will be required to perform pressure testing on a significant number of wells.¹⁰²⁴ From 2021 to 2026, pressure testing increases by nearly five times, with PG&E performing 11 pressure tests in 2021 with an incremental year over year ramp up to over 50 pressure tests required by CalGEM in 2026.¹⁰²⁵

The frequency of pressure testing directly impacts the need for reworks. Emergent work as a result of pressure testing is not a case of poor craftsmanship or work execution. Rather, as PG&E has consistently communicated to CalGEM, increasing pressure testing frequency can weaken the elastomer sealing properties of the packer elements prematurely. CalGEM’s regulations¹⁰²⁶ require the wells be tested to 115 percent MAOP with very limited pressure fluctuation allowed to be considered passing. In order to perform a pressure test without mobilizing a rig, operators must make sure that the entire depth of the wellbore is exposed to 115 percent MAOP to meet the passing criteria. As a result, because well casing near the surface is tested to 115 percent and with the fluid in the annular space between the tubing and casing, the added fluid gradient linearly increases the pressure at the bottom of the well. This means that the packer element and lower portions of the well casing are being tested to approximately 240 percent MAOP. These load cycles imposed on a well and packer elements are outside of

¹⁰²² TURN-07, p. 26, lines 21-22.

¹⁰²³ PG&E-03, Attachment C, CalGEM’s June 15 determination.

¹⁰²⁴ PG&E-16-E, p. 7A-14, lines 6-9 and Figure 7A-1.

¹⁰²⁵ PG&E-16-E, p. 7A-14, lines 12-15.

¹⁰²⁶ PG&E-16-E, pp. 7A-AtchC-2 to 7A-AtchC-3, Sections 1726.6(3) and 1726.6.1.

normal operation, have the potential to stress and weaken the sealing mechanism. PG&E is reasonably estimating that the increase in pressure testing cycles will impact its wells and result in emergent work that needs to be performed. Thus, TURN's argument to limit the forecast of emergent work is unreasonable given the recent changes in CalGEM requirements.¹⁰²⁷

3.6.6.2 PG&E's Unit Cost Forecast is Reasonable

Well reworks are classified into 3 types – Types 1, 1a, and 2.¹⁰²⁸ Because the work for each type varies, the costs also vary. Typically, Type 2 reworks are the most expensive and Type 1 the least expensive.¹⁰²⁹ PG&E calculated a unit cost forecast for each type of rework using a cost calculator and then averaged the costs for the three types of rework to arrive at an overall unit cost forecast.¹⁰³⁰ The average approach attempts to capture the range of costs seen within each Type category as each individual well project can be drastically different from a well of the same type. TURN maintains that PG&E's unit cost estimate is too high and recommends a unit cost of \$3.031 million per well (in 2020 dollars) be adopted compared to PG&E's averaged cost unit cost estimate of \$3.298 (in 2020 dollars).¹⁰³¹ TURN relied on data that included 2018 wells to arrive at its unit cost forecast, as well as estimates of the how much of each type of work would be required during the rate case period.¹⁰³² TURN's proposal to reduce PG&E's unit cost forecast is flawed for a number of reasons.

First, TURN did not consider the fact that Types can change during a rework. As PG&E witness Lucy Redmond explained at trial in response to a question by ALJ DeAngelis, it is “very

¹⁰²⁷ PG&E-16-E, p. 7A-15, lines 5-26.

¹⁰²⁸ PG&E-03, p. 7-27, lines 11-29.

¹⁰²⁹ PG&E-3-ES, WP 7-29, lines 18-22.

¹⁰³⁰ PG&E-03, p. 7-28, lines 1-5; PG&E-3-ES, WP 7-29 to 7-33 (providing cost calculations for each type and average of the three types).

¹⁰³¹ TURN-07, p. 25, lines 7-8.

¹⁰³² TURN-07, p. 25, lines 2-8.

common” for a type to change during inspection and preparation for a rework.¹⁰³³ TURN, however, assumes that the percentages of Types 1, 1A and 2 will remain static over the rate case period based on 2018-2020 data. Given the potential for the rework type to change, it is more reasonable to use PG&E’s unit cost average approach than TURN’s estimate that locks in the type of reworks over a four year period.

Second, in TURN’s forecast, 2018 dollars were included; however, projects completed in 2018 did not include the same scope of work as the work being performed in 2019 and forward to comply with CalGEM regulations.¹⁰³⁴ Beginning in 2019, wells have additional cost of new wellheads, tubulars, and packers that add time and material to the projects.¹⁰³⁵ Additionally, under the new CalGEM regulations, operators are required to use brine to perform the pressure testing during the rework. Previously, operators were permitted to use the polymer fluid already in the wellbore for well control purposes during the rework operation. This fluid type requirement adds additional rig time and cost to change the fluid out to perform the pressure test as well as additional fluid acquisition and disposal costs.¹⁰³⁶ TURN’s use of 2018 data skews its unit cost estimate.

Third, in 2021 and so far in 2022, PG&E has seen permitting time increasing with CalGEM with initial permit receipt and supplemental permits that are required during the course of the project. It is common in well projects for operators to need to seek supplemental permits to complete the well work based on conditions encountered. For example, PG&E may scope and permit a Type 1 well, however, during the course of the inspection identify a feature that needs remediation as a Type 2 well, or the expected location to set a liner or other downhole equipment needs to be adjusted from the planned depth. In order to perform these activities, an operator

¹⁰³³ Tr. Vol. 6, 1000:15 to 1001:27, PG&E/Redmond.

¹⁰³⁴ Tr. Vol. 6, 995:9 to 996:6, PG&E/Redmond.

¹⁰³⁵ PG&E-16-E, p. 7A-16, lines 20-24.

¹⁰³⁶ PG&E-16-E, p. 7A-16, lines 25-31.

must seek a supplemental permit so work can continue. In 2019 and 2020, supplemental permits were treated with high priority by CalGEM given the nature of the rig waiting on orders. However, in 2021 and in the current year of 2022, CalGEM has shifted its process and now supplemental permits are no longer treated as priority, require a minimum of 10 days, and in cases have taken months to receive. In these instances, the work is suspended and the rig is demobilized from the well to prevent unnecessarily incurring day rate charges for the rig equipment and crew. As such, PG&E is seeing an increase in number of rig mobilizations needed to complete projects and multiple days waiting on permits or CalGEM approval.¹⁰³⁷

Finally, increasing scarcity of California local vendors who provide services and materials related to the oil and gas industry, and global supply pressures related to COVID-19 and current events with the Russian invasion of Ukraine. Many California vendors have closed shop or greatly reduced their service offerings and have relocated staff to more oil and gas friendly states, especially as attention is turned to ramping up domestic supply.¹⁰³⁸ This is resulting in higher costs to source and procure materials and to contract with qualified vendors. In fact, Wild Goose and LGS explicitly call out in their testimony that expected higher cost forecasts will materialize due to these phenomena.¹⁰³⁹

3.6.7 Controls and Monitoring – Capital (MAT 3L5)

The scope of this program is to install safety-related equipment to monitor pressure and gas flow at PG&E's storage fields. Projects in this program include installation or replacement of equipment to: (1) monitor injection flow at McDonald Island; (2) monitor annular pressure at all storage fields; and (3) replace older monitoring equipment at McDonald Island. In addition, this program includes necessary controls upgrades at the Los Medanos facility. This equipment mitigates storage well control failures or an inability to monitor well performance parameters

¹⁰³⁷ PG&E-16-E, p. 7A-16, line 32 to p. 7A-17, line 16.

¹⁰³⁸ PG&E-16-E, p. 7A-17, lines 17-26.

¹⁰³⁹ WGL-01, p. 12, lines 8-9.

that can result in a loss of gas isolation, uncontrolled flow, or lost production from a storage well.¹⁰⁴⁰ Our opening testimony and workpapers describe this program and provide evidence demonstrating that the program and PG&E’s cost forecast for the rate case period are prudent and reasonable.¹⁰⁴¹ TURN was the only party that addressed this program and proposed:

TABLE 3-41
CONTROLS AND MONITORING (MAT 3L5): PG&E’S CAPITAL FORECAST AND PARTIES
RECOMMENDED REDUCTIONS (\$000s)^(a)

Party	2020 Rec.	2021	2022	2023	2024	2025	2026
PG&E	\$18,799	\$21,300	\$21,400	\$1,365	\$7,525	\$--	\$--
TURN ^(b)				\$0	\$(7,525)	\$--	\$--

(a) PG&E-16-E, p. 7A-35, Table 7A-9, line 4 (PG&E’s 2020-2022 recorded and forecast costs); PG&E-3-ES, p. v (PG&E’s 2023-2026 forecast).

(b) TURN recommends the removal of costs for installation of new Well Controls and Continuous Monitoring at the Los Medanos field because retention of Los Medanos is unnecessary. This adjustment has no test year impact. PG&E-64, p. 3-60.

TURN’s argument to reduce the forecast by removing control upgrades for Los Medanos is premised entirely on its assertion that the Los Medanos is not needed.¹⁰⁴² The flaws with TURN’s arguments regarding the need to retain Los Medanos are addressed in Section 3.6.4 above.

3.6.8 Well Integrity Assessments – Expense (MAT AH1)

The Integrity Inspections and Surveys Program covers the scope of work to perform integrity inspection and surveys on storage wells including: (1) annual and periodic compliance surveys; (2) thru-tubing barrier inspection surveys; and (3) direct well integrity and production casing/barrier inspections and tests.¹⁰⁴³ The specific types of tests involved are described in

¹⁰⁴⁰ PG&E-03, p. 7-42, lines 6-15.

¹⁰⁴¹ PG&E-03, p. 7-42, line 5 to p. 7-43, line 10; PG&E-3-ES, WP 7-33; PG&E-03, WP 7-38.

¹⁰⁴² TURN-21, p. 12, lines 19-22.

¹⁰⁴³ PG&E-16-E, p. 7A-28, lines 26-30.

detail in PG&E’s opening testimony.¹⁰⁴⁴ Our opening testimony and workpapers describe this program and provide evidence demonstrating that the program and PG&E’s cost forecast for the rate case period are prudent and reasonable.¹⁰⁴⁵ TURN was the only party that addressed this program and proposed:

TABLE 3-42
WELL INTEGRITY ASSESSMENTS (MAT AH1): PG&E’S EXPENSE FORECAST AND
PARTIES RECOMMENDED REDUCTIONS (\$000s)^(a)

Party	2020 Rec.	2021	2022	2023	2024	2025	2026
PG&E	\$4,064	\$4,685	\$5,791	\$9,177	\$9,640	\$8,003	\$10,146
TURN				\$(1,888)	\$(2,269)	\$(2,230)	\$(3,722)

(a) PG&E-16-E, p. 7A-35, Table 7A-8, line 2 (PG&E’s 2020-2022 recorded and forecast costs); PG&E-3-ES, p. iii (PG&E’s 2023 forecast); TURN-21, p. 14 and PG&E-64, p. JCE 3-62 (TURN’s recommendation)

TURN does not oppose PG&E’s forecast unit cost. However, TURN recommends fewer annual inspections than PG&E plans based on its assertion that no new wells are needed given TURN’s revised Peak Day Supply Standard analysis and its proposal that Los Medanos be decommissioned or sold.¹⁰⁴⁶ The flaws with TURN’s argument are addressed above in Sections 3.6.2 and 3.6.4.

3.6.9 Well Reworks – Expense (MAT AH2)

The Reworks and Retrofits Program is an expense program that includes the scope of work to perform reinspections of wells following conversion to tubing an packer as required by CalGEM’s regulations. In addition, this program includes work to address any integrity issues identified as emergent that require a rig mobilization (*i.e.*, response to a failed pressure test).¹⁰⁴⁷ For purposes of this section of our brief, we will refer to the work in this program as

¹⁰⁴⁴ PG&E-03, p. 7-31, line 8 to p. 7-34, line 27 and p. 7-35, Figure 7-6.

¹⁰⁴⁵ PG&E-03, p. 7-30, line 27 to p. 7-36, line 11; PG&E-3-E, WP 7-7 to WP 7-10.

¹⁰⁴⁶ TURN-07, p. 30, lines 12-20; TURN-21, p. 13, lines 6-18.

¹⁰⁴⁷ PG&E-03, p. 7-26, lines 15-31; PG&E-16-E, p. 7A-20, lines 1-6.

“reinspection” work.¹⁰⁴⁸ Our opening testimony and workpapers describe this program and provide evidence demonstrating that the program and PG&E’s cost forecast for the rate case period are prudent and reasonable.¹⁰⁴⁹

TURN, the only party that addressed this program, proposes to entirely eliminate it:

TABLE 3-43
WELL REWORKS (MAT AH2): PG&E’S EXPENSE FORECAST AND PARTIES
RECOMMENDED REDUCTIONS (\$000s)^(a)

Party	2020 Rec.	2021	2022	2023	2024	2025	2026
PG&E	\$--	\$--	\$--	\$3,207	\$3,283	\$5,040	\$24,056
TURN ^(b)				\$(3,207)	\$(3,283)	\$(5,040)	\$(18,657)

(a) PG&E-16-E, p. 7A-35, Table 7A-8, line 3 (PG&E’s 2020-2022 recorded and forecast costs); PG&E-3-ES, p. iii (PG&E’s 2023 forecast).

(b) TURN recommends no funding for MAT AH2 before 2026. TURN-21, p. 14. TURN’s recommendation has been adjusted to reflect PG&E’s forecast updated to correct for the escalation errata. PG&E-64, p. JCE 3-62 shows TURN’s original recommendation based on PG&E’s uncorrected forecast of \$3.292 million.

TURN does not dispute PG&E’s unit cost forecast for reinspections but does recommend that PG&E’s forecast for emergent units for 2023-2026 be reduced to zero and the 2026 forecast for planned work be reduced from 11 units to 3 units.¹⁰⁵⁰ In rebuttal testimony, PG&E provided a table comparing the unit forecasts of TURN and PG&E.¹⁰⁵¹

Ten (10) of the twenty-one (21) well reinspections forecasted by PG&E during the rate case period are associated with emergent work. For these 10 reinspection projects, TURN asserts that emergent work (*i.e.*, reinspections) should not be required on wells that have recently been reworked when undergoing pressure testing and inspection.¹⁰⁵² This is the same argument

1048 CalGEM uses the term “inspection” whereas PHMSA uses “assessment.” Reinspections and re-assessments are considered the same and thus PG&E will use the term reinspection in this brief to refer to both the PHMSA and CalGEM requirements.

1049 PG&E-03, p. 7-24, line 6 to p. 7-27, line 6; PG&E-3-E, WP 7-11.

1050 TURN-07, p. 27, lines 18-19; p. 30, lines 3-6.

1051 See PG&E-16-E, p. 7A-20, Table 7A-6.

1052 TURN-07, p. 28, lines 1-5.

that TURN made for well reworks that are capital and included in MAT 3L3. The flaws with TURN's emergent work analysis are discussed above in Section 3.6.6.1 and apply equally here.¹⁰⁵³

The remaining 11 reinspection projects are scheduled to occur in 2026. PG&E's forecast for these 11 projects assumes that they will be direct casing assessments which we understand are required for wells every seven years.¹⁰⁵⁴ As explained in PG&E's rebuttal testimony, a direct casing inspection involves the mobilization of a rig and is a significant undertaking.¹⁰⁵⁵ TURN asserts that PG&E's 2026 forecast for 11 reinspections is a worst-case scenario stemming from outstanding regulatory guidance from PHMSA and CalGEM. TURN maintains that only three direct casing reinspections will be needed in 2026.¹⁰⁵⁶ TURN's arguments on this point are not well founded.

First, in rebuttal testimony, PG&E explained why it assumed a 7-year reinspection cycle for direct casing assessments based on PHMSA guidance and regulations.¹⁰⁵⁷ TURN tries to counter this argument by pointing to Frequently Asked Questions (FAQs) issued by PHMSA regarding the frequency of direct casing inspections.¹⁰⁵⁸ However, as PG&E explained, these FAQs and PHMSA guidance and regulations, read together, demonstrate that PG&E's assumption of a 7-year reinspection cycle is entirely reasonable.¹⁰⁵⁹

Second, even if PHMSA regulations allowed for less frequent direct casing inspections, CalGEM regulations will likely require these types of inspections every 7 years at a minimum,

¹⁰⁵³ PG&E-16-E, p. 7A-21, lines 1-8.

¹⁰⁵⁴ PG&E-16-E, p. 7A-21, lines 9-23.

¹⁰⁵⁵ PG&E-16-E, p. 7A-21, lines 13-23.

¹⁰⁵⁶ TURN-07, p. 29, lines 17-21.

¹⁰⁵⁷ PG&E-16-E, p. 7A-23, lines 3-28.

¹⁰⁵⁸ TURN-07, p. 29, lines 9-10.

¹⁰⁵⁹ PG&E-16-E, p. 7A-24, line 3 to p. 7A-25, line 19.

and likely even more frequently. The current CalGEM regulations require a 2-year reinspection frequency, although PG&E has petitioned for an alternative frequency.¹⁰⁶⁰ PG&E is waiting for CalGEM to make a determination regarding the frequency of inspections but notes that CalGEM has continued to require SoCal Gas to maintain a 2-year inspection cycle on its gas storage well direct casing inspections, which is substantially shorter than 7 years.¹⁰⁶¹ Indeed, contrary to TURN's claim that PG&E used a "worst case scenario" to develop its forecast, PG&E's use of a 7-year reinspection cycle is entirely reasonable compared to a potential 2-year cycle currently in CalGEM's regulations.¹⁰⁶²

Third, in rebuttal testimony, PG&E provided a detailed analysis of the impact of the PHMSA regulations and potential CalGEM requirements for reinspections assuming a 7-year and 5-year cycle. Under either scenario, the number of reinspections will likely exceed the number forecast by PG&E for 2026.¹⁰⁶³

Fourth, it is notable that other storage providers make the same 7-year reinspection cycle assumption as PG&E makes. In discovery, Wild Goose and LGS indicated that they understand that direct casing reinspections every 7 years "which would match PHMSA rules."¹⁰⁶⁴ While TURN does not operate a gas storage facility and does not have a compliance requirement for reinspection, the three entities in this proceeding that do operate natural gas storage facilities and have reinspection compliance obligations all agree that a 7-year reinspection cycle is likely required by PHMSA regulations.

¹⁰⁶⁰ Tr. Vol. 6, 1010:10-25, PG&E/Redmond.

¹⁰⁶¹ PG&E-16-E, p. 7A-25, line 23 to p. 7A-26, line 9. It is PG&E's understanding that CalGEM has recently granted a one-time alternate frequency for SoCal Gas for a small subset of wells that have been inspected twice already, 24-months apart. For this small population of essentially brand-new wells, PG&E understands CalGEM has granted an extension for the next direct casing inspection (with a rig) interval out to a maximum of five years.

¹⁰⁶² Tr. Vol. 6, 1023:18 to 1024:10, PG&E/Redmond.

¹⁰⁶³ PG&E-16-E, p. 7A-27, line 4 to p. 7A-28, line 22, and Figure 7A-5.

¹⁰⁶⁴ PG&E-35, Wild Goose and LGS response to PGE_Joint-LW004, Question 2.

Fifth, TURN proposes 3 direct casing reinspections in 2026 instead of the 11 forecasted by PG&E.¹⁰⁶⁵ TURN provides absolutely no evidence to support this forecast. On the other hand, PG&E’s forecast is based on actual data regarding initial baseline work and the subsequent need for and timing of reinspections. Specifically, PG&E performed baseline inspections along with conversion or plug and abandonment for 15 wells in 2019 in alignment with CalGEM regulations. Of the 15 wells, four were plugged and abandoned. Thus, PG&E forecast that on a 7-year reinspection interval, 11 wells are due for reinspection.¹⁰⁶⁶

In sum, as PG&E explained in rebuttal testimony “[g]iven the significant regulatory uncertainty described above, PG&E’s forecast is reasonable and may even underestimate the units should CalGEM prescribe a tighter re-assessment interval.”¹⁰⁶⁷

3.6.10 Gas Storage Balancing Account

In the 2019 GT&S Rate Case, the Commission adopted the Gas Storage Balancing Account or “GSBA” as a two-way balancing account given the significant regulatory uncertainty regarding gas storage regulations and requirements.¹⁰⁶⁸ In this rate case, PG&E has proposed continuing the GSBA given the ongoing uncertainty regarding gas storage regulations and costs, as well as the uncertainty that exists inherent in storage well work. TURN was the only party that addressed the GSBA and it also supported retaining it as a two-way balancing account.¹⁰⁶⁹ Thus, there is no dispute that the GSBA should be retained as a two-way balancing account during the rate case period.

¹⁰⁶⁵ TURN-07, p. 29, lines 19-21.

¹⁰⁶⁶ PG&E-16-E, p. 7A-26, lines 10-15.

¹⁰⁶⁷ PG&E-16-E, p. 7A-26, lines 22-24.

¹⁰⁶⁸ D.19-09-025, pp. 94-95; see also PG&E-03, p. 7-61, line 27 to p. 7-62, line 8 (describing the GSBA).

¹⁰⁶⁹ TURN-07, p. 3, lines 10-16.

PG&E is also proposing modifications to how costs are recovered through the GSBA. Once the Commission adopts expense and capital forecasts for gas storage in this proceeding, those forecasts will be reflected in rates. In the GSBA, PG&E tracks the revenues it receives based on approved rates, as well as the actual expenditures it incurs. To the extent expenditures exceed revenues, PG&E is entitled to recover these costs after submitting an application to the Commission. To the extent expenditures are less than revenues, the amount collected over revenues is return to PG&E's customers.

In the 2019 GT&S rate case, the Commission required that “[i]n the next rate case, PG&E shall submit an analysis comparing the total recorded costs with the authorized amount, and the Commission shall determine whether the transactions in the balancing account are reasonable.”¹⁰⁷⁰ This creates a substantial delay in returning over-collected amounts to customers or recovering under-collected costs in rates. Because rate cases are now based on a 4 year cycle, and the rate cases themselves typically take several years to reach resolution, the return of excess amounts or recovery of under-collected amounts can take years.

To address this problem, PG&E proposed filing a Tier 2 advice letter each year after the recorded costs for the year are final, typically in April. The advice letter would provide details regarding the actual costs incurred as compared to the adopted forecast amount, indicate whether there was an over- or under-collection, and create a vehicle for PG&E to either return the over-collection to customers or to recover the under-collection in rates.¹⁰⁷¹ If a party protests PG&E's Tier 2 advice letter, that party could ask for the Commission Staff or the Commission to convert the Tier 2 advice letter into a Tier 3 advice letter or that PG&E be required to file an Application in lieu of the Tier 2 advice letter.¹⁰⁷² However, if the Tier 2 advice letter is not protested, it can be reviewed and approved by Commission Staff to expedite the return of

¹⁰⁷⁰ D.19-09-025, p. 95.

¹⁰⁷¹ PG&E-03, p. 7-62, lines 12-16; PG&E-16-E, p. 7A-32, lines 10-17.

¹⁰⁷² PG&E-16-E, p. 7A-33, lines 8-11.

customer funds or the collection of under-collected amounts. This also promotes administrative efficiency. The Commission has a heavy workload of applications and streamlining the process so that one less application needs to be filed is beneficial to the Commission and parties.

TURN is the only party that opposes these modifications, proposing that an application should be required if “recorded costs exceed the adopted forecasts” in *any* amount.¹⁰⁷³ TURN argues that a Tier 2 advice letter does not require Commission approval and does not provide parties time to conduct discovery and fully test reasonableness of the expenditures over the adopted amount.¹⁰⁷⁴

TURN’s proposal will only result in continued delay and is unreasonable. There may be circumstances where the GSBA recorded amounts exceed the adopted costs by a very small amount. For example, in 2023, PG&E is forecasting approximately \$124 million in expense and capital expenditures. If this forecast is adopted by the Commission, and PG&E were to exceed the forecast by \$1 million, this would be less than a one percent difference between the adopted and recorded amounts. However, under TURN’s proposal, PG&E would still be required to file an application, which would result in considerable time and expense for the Commission and parties for a relatively small difference between the adopted amount and recorded costs.¹⁰⁷⁵

More importantly, PG&E’s proposal allows for parties to review the Tier 2 advice letter and request that it be converted to a Tier 3 advice letter or application, which requires the Commission to issue a decision and approve the amounts presented. In the example above, if TURN believes that the actual 2023 expenses merit a Tier 3 advice letter or application, TURN can make that recommendation to the Commission. TURN’s proposal that an application automatically be required may well result in PG&E, the parties, and the Commission being required to conduct a much more time intensive process that is not warranted by the amount at

¹⁰⁷³ TURN-07, p. 4, lines 7-9.

¹⁰⁷⁴ TURN-07, p. 4, lines 11-15.

¹⁰⁷⁵ PG&E-16-E, p. 7A-32, line 25 to p. 7A-33, line 16.

issue. The Commission should adopt PG&E's proposal to modify the GSBA process so that it is timely and efficient.

3.7 Gas Operations and Maintenance

Exhibit PG&E-03 Chapter 8 presents the 2023 GRC forecast for operations and maintenance (O&M) activities that cover both GD and GT&S assets. PG&E's O&M forecast is subdivided into three chapters: Chapter 8 (O&M Programs); Chapter 9 (Corrosion Programs); and Chapter 10 (Leak Management Programs). The programs in these three chapters support the following asset families: Distribution Mains and Services;¹⁰⁷⁶ Transmission Pipe;¹⁰⁷⁷ Measurement and Control (M&C); Compression and Processing (C&P); Compressed Natural Gas (CNG)/Liquefied Natural Gas (LNG);¹⁰⁷⁸ and Storage.¹⁰⁷⁹ Maintenance of gas facilities is an integral component to managing threats and the O&M programs are foundational to enable the Asset Family Owners to identify and mitigate threats on the gas system. The requested expenditures will help mitigate safety and reliability risks related to delivering gas through approximately 43,400 miles of gas main, nearly 3.6 million gas service connections, and approximately 6,600 miles of transmission pipeline.

PG&E's Corrected Forecast for GD expense is \$213.815 million.¹⁰⁸⁰ The expense forecast includes work tracked in seven MWCs, of which are three are uncontested: MWC DD, Provide Field Service; MWC FH, GD Preventive Maintenance; MWC FI, GD Corrective Maintenance; and MWC JQ, Gas Integrity Management. See Appendix A.

¹⁰⁷⁶ PG&E-03, Ch. 4.

¹⁰⁷⁷ PG&E-03, Ch. 5.

¹⁰⁷⁸ M&C, C&P and CNG/LNG are addressed in PG&E-03, Ch. 6.

¹⁰⁷⁹ PG&E-03, Ch. 7.

¹⁰⁸⁰ PG&E-16-E, p. 8-6, Table 8-1, line 27.

PG&E's Corrected Forecast for GT&S expense is \$71.938 million.¹⁰⁸¹ The expense forecast includes work tracked in four MWCs, of which three are uncontested: MWC JO, Gas Transmission Pipeline Maintenance; MWC JP, Gas Transmission Station Maintenance; and MWC JT, Gas Transmission Reliability and General Maintenance. See Appendix A.

PG&E's Corrected Forecast for Gas Distribution Operations and Maintenance is \$285.753 million. PG&E's JCE forecast for Gas Distribution Operations and Maintenance is \$297.061 million.¹⁰⁸²

PG&E's Corrected Forecast for GD capital is \$9.955 million in 2021, \$9.942 million in 2022, \$9.440 million in 2023, \$9.676 million in 2024, \$9.899 million in 2025, and \$10.127 million in 2026.¹⁰⁸³ PG&E's JCE forecast for capital expenditures forecast is \$10.464 million in 2021, \$10.502 million in 2022, and \$10.574 million in 2023, \$10.554 million in 2024, \$10.545 million in 2025, and \$10.528 million in 2026.¹⁰⁸⁴ PG&E's capital forecast is tracked in two MWCs, one of which, MWC 74 – Regulator Replacement, is uncontested. See Appendix A.

Of the 61 expense MATs related to Gas Distribution Operations and Maintenance, only 3 are disputed. Similarly, for the 2 gas distribution capital MATs, only 1 is disputed. The undisputed programs, associated MATs, and corresponding expense and capital forecasts are identified in Appendix A. In the remainder of this Section 3.7, we address the following disputed programs:

¹⁰⁸¹ PG&E-3-ES, p. iii, which reflects PG&E's rebuttal forecast updated with corrected escalation factors.

¹⁰⁸² PG&E-64, p. 3-1, Table 3A-1, lines 11-20.

¹⁰⁸³ PG&E-16-E, p. 8-41, Table 8-9, line 4 (2021 and 2022) and PG&E-3-ES, p. v, which reflects PG&E's rebuttal forecast updated with corrected escalation factors. (2023-2026).

¹⁰⁸⁴ PG&E-64, p. 3-6, Table 3B-1, lines 13-14 (2023); p. 3-10, Table 3B-2, lines 13-14 (2022); and p. 3-14, Table 3B-3, lines 13-14 (2021). Forecasts for 2024-2026 are not included in the JCE but are provided here for reference.

TABLE 3-44
SUMMARY OF ISSUES ADDRESSED IN SECTION 3.7

Section	Disputed Program	Impacted MATs
3.7.1	Locate and Mark	Expense (MAT DFA)
3.7.2	Standby Governance	Expense (MAT DFB)
3.7.3	Meter Protection Program	Expense (MAT EXB)
3.7.4	Relocation of Meter Sets	Capital (MAT 27A)

3.7.1 Locate and Mark – Expense (MAT DFA)

The Locate and Mark Program activities are required to identify PG&E’s distribution and transmission assets for third-parties who plan to dig near those assets pursuant to 49 CFR, Part 192.614. In addition, California Government Code, Section 4216 requires PG&E to belong to and share the costs of operating the regional “one-call” notification system. The one-call system is commonly referred to as Underground Service Alert (USA). Excavators must contact 811 prior to proposed excavation, generating a notification (USA ticket). USA tickets are transmitted electronically to PG&E to respond to or “work.” PG&E’s response may include locating and field marking all subsurface installations identified within the area of proposed excavation, providing records of the locations of the subsurface installations, or advising the excavator PG&E operates no facilities within their proposed area of excavation.¹⁰⁸⁵

PG&E’s 2023 unit forecast is based on the number of Locate and Mark USA tickets worked in 2019 split between GD and GT, with a 12 percent year over year escalation applied. PG&E uses the 12 percent increase seen in ticket volume between 2018 and 2019.¹⁰⁸⁶ PG&E’s unit cost forecast is based on a three-year average of recorded costs (2017-2019) with escalation.¹⁰⁸⁷ For the GD unit cost forecast, the following additional unit cost considerations were added: (1) ten minutes was added to the three-year average job time of 35 minutes to capture the additional time it takes to respond to tickets (new ticket management system as well

¹⁰⁸⁵ PG&E-03, p. 8-10, line 25 to p. 8-12, line 12.

¹⁰⁸⁶ PG&E-16-E, p. 8-11, lines 2-5.

¹⁰⁸⁷ PG&E-03, WP 8-11 (GD); PG&E-3-E, WP 8-23 (GT).

as updates to the Locate and Mark field guide and field procedures), and (2) Fiber Optic costs which were previously recorded to IT.¹⁰⁸⁸ TURN and Cal Advocates address the GD forecast for this program only and propose:

TABLE 3-45
GAS DISTRIBUTION LOCATE AND MARK (MAT DFA): PG&E’S EXPENSE FORECAST
AND PARTIES RECOMMENDED REDUCTIONS (\$000s)^(a)

Party	2020 Rec.	2021	2022	2023
PG&E (DFA – GD)	\$29,085	\$40,915	\$67,244	\$77,595
Cal Advocates (DFA – GD)				\$(40,704)
TURN (DFA – GD)				\$(3,527)
(a) PG&E-16-E, p. 8-39, Table 8-7, line 9 (2020-2023 recorded and forecast amounts); PG&E-64, p. JCE 3-79 (Cal Advocates’ recommendation); PG&E-64, p. JCE 3-80 (TURN’s recommendation).				

TURN proposes a 2023 GD Locate and Mark MAT DFA forecast of \$74.1 million, compared to PG&E’s forecast of \$77.6 million, which results in an expense reduction of \$3.5 million. TURN recommendation is based on a 2023 unit forecast (tickets worked) of 863,682 as compared to the 904,808 units forecast by PG&E.¹⁰⁸⁹ TURN’s recommendations use an annual growth rate of ten percent for Locate and Mark tickets, beginning in 2020,¹⁰⁹⁰ rather than PG&E’s 12 percent year over year increase, based on its claim that “the recorded average annual increase in tickets worked from 2016 – 2019 is ten [percent]”¹⁰⁹¹ and that it is unlikely the pace of Areas of Continual Excavation (ACE) tickets will increase sufficiently to justify a 12 percent growth rate.¹⁰⁹²

Cal Advocates recommends a 2023 forecast of \$36.9 million for GD Locate and Mark MAT DFA, which is \$40.7 million lower than PG&E’s request of \$77.6 million. Cal Advocates’

1088 PG&E-03, WP 8-11.

1089 PG&E-16-E, p. 8-11, lines 23 -27.

1090 TURN-06, p. 3, lines 14-16.

1091 TURN-06, p. 30, lines 16-18.

1092 TURN-06, p. 31, lines 3-10.

recommendation is based on a 2023 unit (tickets worked) forecast of 688,134 as compared to the 904,808 units forecast by PG&E and a reduction in unit costs. TURN's and Cal Advocates' arguments are addressed below.

3.7.1.1 PG&E's Forecast of 12 Percent Growth is Reasonable

PG&E used the 12 percent increase in ticket volume between 2018 and 2019 as the basis for the year-over-year ticket volume increase because 2019 was the most recent full year of tickets worked that was not impacted by work stoppages caused by the COVID-19 pandemic.¹⁰⁹³ PG&E believes using the ticket volume from the most recent years not affected by COVID-19 (*i.e.*, 2018-2019), escalated by the growth rate seen in those years, best reflects the impact from PG&E's continual damage prevention public education and outreach efforts that promote the use of the 811 system throughout the years.¹⁰⁹⁴

The 12 percent growth rate also accounts for additional ticket volume expected in the future related to the CCR, Title 19, Division 4 regulations, enacted July 1, 2020 (referred to hereinafter as the new regulations) which established the California Underground Facilities Safe Excavation Board's (Excavation Board) excavation investigation and enforcement authority, including in Areas of Continual Excavation or ACE.¹⁰⁹⁵ In early 2020, the Excavation Board developed a strategic plan to serve as a guiding document to inform its approach on the next three years. One of the Excavation Board's objectives includes targeting education and outreach for ACE tickets. The California Dig Safe Board 2020 Results Report states that planned in-person events targeting outreach to these groups, were hampered by the COVID-19

¹⁰⁹³ PG&E-16-E , PG&E's response to Data Request TURN_049-Q01Rev01(d.ii), dated 4/1/22, p. AppA-342.

¹⁰⁹⁴ PG&E-16-E p. 8-12, lines 18-28.

¹⁰⁹⁵ PG&E-16-E, p. 8-11, lines 5-11.

pandemic.¹⁰⁹⁶ The report goes on to say that activities are expected to resume as the uptick of the new tickets remains low in comparison to the size and scope of this type of excavation in the state. Therefore, even though the expected growth in tickets has not materialized yet, PG&E expects to see an increase in tickets by 2023 as a result of the Excavation Board continuing to develop its oversight.¹⁰⁹⁷

TURN uses the ten percent ticket volume increase seen between 2016-2019 as the basis for its forecast. TURN's approach is flawed. First, as noted above, this 4-year average does not represent the most recent pre-COVID growth rate use seen from 2018 to 2019, and therefore understates likely growth in tickets. Second, TURN incorrectly attributes PG&E's 12 percent forecast ticket volume increase to ACE tickets alone.¹⁰⁹⁸ While the new regulations include implementing the use of ACE tickets, they also include investigation and enforcement by the Excavation Board of all excavators, not just in ACE areas. PG&E expects this will increase ticket volumes not only in ACE areas, but more generally as well.¹⁰⁹⁹

Cal Advocates' recommendation to use a five percent year-over-year increase in tickets worked, based on the average annual increase in tickets worked from 2016-2020, is equally flawed.¹¹⁰⁰ First, this 6-year average includes data from almost 7 years ago (2016) that is not

¹⁰⁹⁶ This information is publicly available on the California Underground Facilities Safe Excavation Board website. PG&E-16-E, PG&E provided a link in PG&E's response to Data Request Cal Advocates_181-Q06(b), dated 12/21/21, pp. AppA-345 to AppA-346.

¹⁰⁹⁷ PG&E-16-E, p. 8-13, lines 9-20.

¹⁰⁹⁸ TURN calculated that ACE tickets amounted to five-thousandths of one percent of the tickets PG&E worked in 2021. [TURN-06, p. 31, lines 6-7.] TURN calculates this percentage by dividing the number of onsite meetings performed for ACE tickets completed between July 2020 and December 31, 2021 (34), by PG&E's 2021 ticket forecast (723,318). This calculation is incorrect because it compares actual work performed to a forecast and uses only the portion of Locate and Mark tickets that resulted in onsite meetings, which does not reflect the total number of Locate and Mark tickets worked. PG&E-16-E, p. 8-13, fn. 12.

¹⁰⁹⁹ PG&E-16-E, p. 8-13, line 21 to p. 8-14, line 2.

¹¹⁰⁰ CALPA-02, p. 41, lines 23-24.

representative of today’s conditions and also includes the non-typical year of 2020 that was affected by COVID-19.¹¹⁰¹ PG&E used the 12 percent increase as seen in ticket volume between 2018 and 2019 as the basis for the year over year ticket volume increase because 2019 was the most recent full year of tickets worked that was not impacted by work stoppages caused by the COVID-19 pandemic. Second, Cal Advocates’ five percent ticket growth recommendation does not take into account the aggressive and escalating outreach to excavators being implemented by the Excavation Board pursuant to the new regulations as described above.

3.7.1.2 PG&E’s Unit Cost is Reasonable

Cal Advocates recommends using the 2020 unit cost of \$49, escalated to \$54 for the 2023 unit cost,¹¹⁰² as opposed to PG&E’s unit cost of \$86. To support its position, Cal Advocates asserts that “[t]he proposed job time increase in the Test Year was already captured in 2020 because the new regulatory oversights and requirements were already implemented by July 1, 2020.”¹¹⁰³ Cal Advocates unit cost approach is flawed. First, 2020 recorded costs are not a reasonable foundation for the unit cost because 2020 did not represent normal operating conditions as it was impacted by work stoppages caused by the COVID-19 pandemic.¹¹⁰⁴

Second, the 2020 recorded cost of \$29.1 million used by Cal Advocates in its unit cost calculation includes a Locate and Mark Order Instituting Investigation (OII) reduction of approximately \$24.9 million.¹¹⁰⁵ The adjustment reflects shareholder-funded spend in compliance with the Presiding Officer’s Decision (D.20-02-036) adopting the Locate and Mark OII Settlement Agreement with modifications in Appendix A for the System Enhancement

¹¹⁰¹ Even TURN acknowledges that the number of tickets worked in 2020 dropped due to COVID-19 issues. See TURN-06, p. 30, lines 16-20.

¹¹⁰² CALPA-02, p. 43, lines 15-17.

¹¹⁰³ CALPA-02, p. 43, lines 9-11.

¹¹⁰⁴ PG&E-16-E, PG&E’s response to Data Request TURN_049-Q01Rev01(d.ii), dated 4/1/22, p. AppA-342.

¹¹⁰⁵ PG&E-03, WP 8-11, line 32.

Initiative pertaining to Locate and Mark staffing. The duration of this System Enhancement Initiative is through the year 2022.¹¹⁰⁶ The 2020 unit cost using the full 2020 recorded spend of the GD Locate and Mark Program is over \$90 million, as shown in PG&E's opening workpapers.¹¹⁰⁷ PG&E expects that beginning in 2023, this System Enhancement Initiative will have been met and the associated ongoing costs that were shareholder-funded costs prior to 2023, will become part of base ratepayer expenses. PG&E expects to maintain the staffing level to work the volume of tickets forecast. By excluding shareholder funded costs from its unit cost calculation, Cal Advocates is understating the unit cost per ticket worked going forward.¹¹⁰⁸

Finally, PG&E disagrees with Cal Advocates' statement that because the new regulatory oversights and requirements became effective July 1, 2020, the costs were already captured in the 2020 recorded costs. The first half of 2020 recorded costs do not reflect impacts of the regulatory change. Moreover, the impacts will be felt over time as the new regulations are fully implemented and even the second half of 2020 does not reflect the increase in tickets that will ultimately be generated once the regulations are fully implemented.¹¹⁰⁹

3.7.2 Standby Governance – Expense (MAT DFB)

In the standby process, a PG&E field employee monitors excavation activity on both GD and GT assets in a watch and protect capacity to prevent damage to PG&E's critical facilities. Examples of the types of activities where PG&E performs a standby include excavations that are within five feet of the nearest edge of a critical facility and boring activities that cross a critical facility within ten feet of its nearest edge.¹¹¹⁰ PG&E's 2023 forecast for GD Standby

¹¹⁰⁶ D.20-02-036, Appendix A, System Enhancement Initiative Pursuant to Paragraphs III.B.4 and III.B.10 of the Settlement Agreement.

¹¹⁰⁷ PG&E-03, WP 8-11, lines 21-23.

¹¹⁰⁸ PG&E-16-E, p. 8-16, line 22 to 8-17, line 11.

¹¹⁰⁹ PG&E-16-E, p. 8-17, lines 12-19.

¹¹¹⁰ PG&E-03, p. 8-12, line 13 to p. 8-13, line 5.

Governance is \$0.5 million and for GT Standby Governance is \$7.5 million.¹¹¹¹ TURN is the only party that addresses this program and proposes:

TABLE 3-46
STANDBY GOVERNANCE (MAT DFB): PG&E’S EXPENSE FORECAST AND PARTIES
RECOMMENDED REDUCTIONS (\$000s)^(a)

Party	2020 Rec.	2021	2022	2023
PG&E (DFB – GD)	\$22	\$424	\$415	\$451
TURN				\$(9)
PG&E (DFB – GT)	\$6,096	\$5,857	\$6,459	\$7,459
TURN				\$(2,110)

(a) PG&E-16-E, p. 8-39, Table 8-7, line 10 (GD 2020-2023 recorded and forecast amounts); PG&E-16-E, p. 8-40, Table 8-8, line 2 (GT 2020-2022 recorded and forecast amounts); PG&E-3-ES, p. iii (GT 2023 forecast); PG&E-64, p. JCE 3-80 (TURN’s recommendations).

TURN proposes a 2023 expense forecast for GD Standby Governance of \$0.4 million as compared to PG&E’s expense forecast of \$0.5 million, which results in an expense reduction of approximately \$9 thousand dollars,¹¹¹² and a 2023 GT Standby Governance forecast of \$5.3 million, which is \$2.1 million lower than PG&E’s forecast of \$7.5 million.¹¹¹³ TURN bases its recommendations for GD Standby Governance on a growth rate for standby tickets of 10 percent (as opposed to 12 percent proposed by PG&E) beginning in 2020 and annually thereafter.¹¹¹⁴ TURN bases its GT Standby Governance recommendations on PG&E’s 2019 recorded units of 5,221 without escalation.

3.7.2.1 PG&E’s GD Standby Governance Forecast is Reasonable

TURN’s proposed growth rate of 10 percent for GD Standby Governance units is not reasonable. PG&E’s forecasted increase in Locate and Mark tickets worked is also expected to drive up the need to perform standbys due to the correlation between USA tickets worked in the

¹¹¹¹ PG&E-16-E, p. 8-18, lines 18-20.

¹¹¹² PG&E-16-E, p. 8-19, lines 16-20.

¹¹¹³ PG&E-16-E, p. 8-20, lines 20-23.

¹¹¹⁴ TURN-06, p. 31, lines 11-13.

Locate and Mark Program (MAT DFA) and the need for standby activities (MAT DFB). Given this correlation, the 12 percent rate recommended by PG&E for DFA (see Section 3.7.1.1 above) should also apply to DFB work. As PG&E forecasts an increase in Locate and Mark tickets worked, it is expected that the need to perform standbys will also increase.¹¹¹⁵

3.7.2.2 PG&E's GT Standby Governance Forecast is Reasonable

For GT Standby Governance TURN recommends basing the 2023 unit forecast on the 2019 actual recorded standby ticket units (5,221), without escalation.¹¹¹⁶ TURN asserts that PG&E's forecast is unreasonably high and the historic record does not support a 12 percent annual escalation as recommended by PG&E.¹¹¹⁷ To support this recommendation TURN explains that: (1) the number of units have not trended in one direction but instead have fluctuated over the years; and (2) the number of units decreased significantly in 2019 from the prior three years, and remained at a lower level in 2020 as a result of the efforts of the Gas Standby Governance team which is still in place.¹¹¹⁸

TURN's arguments on this point are flawed. Since 2019, standby units have trended higher, and PG&E expects the need for standby activities will continue to increase in direct correlation with the increase in Locate and Mark tickets worked. In 2020, for example, recorded tickets increased to 5,774 (an 11 percent increase from 2019).¹¹¹⁹ Moreover, PG&E continually looks for ways to improve damage prevention activities, including evaluating events across the industry and learning from best practices. For example, after the Merrimack Valley gas incident,

¹¹¹⁵ PG&E-16-E, p. 8-20, lines 3-16.

¹¹¹⁶ TURN-05, p. 10 and Attachment 3, Schedule 1.

¹¹¹⁷ TURN-05, p. 10.

¹¹¹⁸ TURN-05, p. 11.

¹¹¹⁹ PG&E-16-E, p. 8-21, lines 6-10.

the AGA issued recommendations for operators to consider having qualified personnel on site during excavation near and around regulator stations that have buried control lines.¹¹²⁰

Damage prevention activities do not remain static. PG&E acknowledges that beginning in 2019, the standby governance team implemented new processes and procedures that reduced standbys and made the group more efficient and effective. Those processes and procedures were fully implemented and will be applied moving forward. However, as PG&E forecasts an increase in Locate and Mark tickets and industry recommendations evolve, it is also expected that the need to perform standbys will also increase.¹¹²¹

3.7.3 Meter Protection Program (MAT EXB)

The purpose of the Meter Protection Program (MPP) is to protect meters and risers that are vulnerable to vehicular damage, and to install service valves where existing service valves are inaccessible. Preventing damage from vehicles is required in accordance with 49 CFR, § 192.353. Inadequate meter protection is one type of abnormal operating condition (AOC) noted when PG&E field personnel visit a meter set, whether as part of a survey or for other reasons, that may need follow up or remediation. Meter protection is primarily accomplished through the installation of steel posts (bollards). In some instances, access issues may occur where no access was available to perform meter protection work, and these instances are referred to as “Can’t Get In” (CGI) locations. These locations are often more complex and costly to remediate.¹¹²²

PG&E’s 2023 forecast for the MPP is \$35.4 million, for 43,193 meter protection locations, at a unit cost of \$821.¹¹²³ The 43,193 units forecast for 2023 are comprised of:

¹¹²⁰ PG&E-03, p. 8-12, line 25 to p. 8-13, line 4.

¹¹²¹ PG&E-16-E, p. 8-21, line 20-27.

¹¹²² PG&E-03, p. 8-34, line 21 to p. 8-35, line 27.

¹¹²³ PG&E-3-ES, WP 8-21, line 3.

- 3,410 CGI locations (no access): This is based on an eight percent CGI rate seen from work performed by PG&E’s contractor in 2020.¹¹²⁴
- 19,380 New Finds: This is based on expected new AOC locations identified through routine Leak Survey and Atmospheric Corrosion (AC) inspection plans along with field services activities, with a two year remediation plan based on PG&E’s internal guidelines for performing corrective work on the gas distribution system.¹¹²⁵ A find rate was derived from meter protection locations identified in 2020 through the AC inspection and Leak Survey programs.¹¹²⁶ The find rate was then applied to the 2021 inspection plan to determine the forecast volume of “New Finds” that would be targeted for execution in 2023 under PG&E’s two-year repair time frame.¹¹²⁷
- 20,283 Existing Locations: The Existing Locations (or AOC backlog as it is also referred to) reflects the total pending meter protection locations that are planned for remediation by 2026 as approved by the Asset Family Owner based on relative risk ranking.¹¹²⁸ The total pending meter protection locations (81,133) were divided by the four-year 2023 rate case period.¹¹²⁹
- 120 Customer Call-ins: This is based on approximations of customer generated monthly requests received over the last five years.¹¹³⁰

The 2023 unit cost forecast reflects a blend of Non-CGI and CGI remediation costs.¹¹³¹

TURN and Cal Advocates addressed this program and propose:

¹¹²⁴ PG&E-3-ES, WP 8-21, lines 25 and 28.

¹¹²⁵ PG&E-3-ES, WP 8-21, lines 25 and 29.

¹¹²⁶ PG&E-16-E, PG&E’s response to Data Request CalAdvocates_183-Q02Supp01(c), dated 1/10/22, pp. AppA-348 to AppA-349.

¹¹²⁷ *Id.*

¹¹²⁸ PG&E-3-ES, WP 8-21, lines 25 and 31.

¹¹²⁹ PG&E-16-E, PG&E’s response to Data Request CalAdvocates_183-Q02Supp01(c), dated 1/10/22, pp. AppA-348 to AppA-349.

¹¹³⁰ PG&E-3-ES, WP 8-21, lines 25 and 29.

¹¹³¹ PG&E-3-ES, WP 8-21, lines 11-21.

TABLE 3-47
METER PROTECTION PROGRAM (MAT EXB): PG&E'S EXPENSE FORECAST AND
PARTIES RECOMMENDED REDUCTIONS (\$000s)^(a)

Party	2020 Rec.	2021	2022	2023
PG&E	\$11,471	\$7,938	\$8,046	\$35,442
Cal Advocates				\$(22,782)
TURN				\$(11,771)
(a) PG&E-16-E, p. 8-39, Table 8-7, line 12 (2020-2023 recorded and forecast amounts); PG&E-16-E, p. 8-5, Table 8-1, line 10 (Parties' recommendations).				

TURN's recommendation is based on extending the pace for remediating Existing Location units over 20 years, instead of completing remediations by 2026 as forecast by PG&E.¹¹³² TURN also recommends the Commission require PG&E provide an RSE for Meter Protection for the Loss of Containment on Gas Customer Connected Equipment (CCE) risk for the next GRC.¹¹³³ This recommendation is addressed in Section 3.2.2.4 of this opening brief.

Cal Advocates bases its recommendations on a unit reduction to 15,421 meter protection locations in 2023 in contrast to PG&E's request of 43,193 locations.¹¹³⁴ Cal Advocates applies reductions to each of the four components which make up PG&E's MPP unit forecast: (1) CGIs, (2) New Finds, (3) Existing AOCs, and (4) Customer Call-Ins.

TURN's and Cal Advocates' arguments are addressed below.

3.7.3.1 Delaying MPP Remediation Will Result in a Backlog of Meters

TURN recommends remediating the Existing Locations backlog over 20 years. Delaying the meter protection work beyond PG&E's forecast timeframe of 2023-2026 (a four year period) is unreasonable. By performing the necessary work and installing the bollards where needed, customers' gas meters can be protected from the risk of vehicular damage and the potential for gas release. Extending the duration of this remediation will only contribute to the potential of

¹¹³² TURN describes this as a 5-year forecast, when it is a 4-year forecast (2023-2026).

¹¹³³ TURN-06, p. 33, lines 16-18.

¹¹³⁴ CALPA-02, p. 45, lines 5-6.

having another backlog of work as additional locations are found and added to the MPP scope.¹¹³⁵

TURN relies on three arguments to support its delay proposal. First, TURN argues that the slowing the pace of the MPP program is justified because the program has a “...low RSE and B/C ratio”¹¹³⁶ As discussed in in Section 2.3 of this opening brief, the RAMP modelling process and RSE methodology is evolving and is not sufficiently mature to support funding decisions.

Second, TURN claims its proposal “allows remediation of the existing backlog in two-thirds of the time it took PG&E to remediate the 1990 backlog under the Meter Protection Program.”¹¹³⁷ However, the scope of the original Meter Protection Program¹¹³⁸ from the 1990 GRC was approximately 400,000 locations¹¹³⁹ which was much higher than the pending Existing Location volume of 81,133. Therefore that program is not comparable to the current program and PG&E’s proposed pace for remediations of Existing Locations.¹¹⁴⁰

Finally, TURN states its approach “gives the Commission and PG&E time to consider how this effort fits into the gas Long-Term Planning Rulemaking, before a large additional investment in meter protection is completed.”¹¹⁴¹ However, “[a] Commission adopted transition framework for the long term future of [natural gas] utilities will . . . not be finalized until 2022 or beyond. [N]otwithstanding the expected decline in throughput, PG&E has an

¹¹³⁵ PG&E-16-E, p. 8-24, lines 9-17.

¹¹³⁶ TURN-06, p. 33, line 24 to p. 34, line 1.

¹¹³⁷ TURN-06, p. 34, lines 1-4.

¹¹³⁸ The original meter protection program was ordered in the 1990 GRC (D.89-12-057). With the completion of its original commitments, this program transitioned from a dedicated program to ongoing corrective maintenance. PG&E-03, p. 8-35, lines 2-7.

¹¹³⁹ PG&E-03, WP 8-70.

¹¹⁴⁰ PG&E-16-E, p. 8-26, lines 8-13.

¹¹⁴¹ TURN-06, p. 34, lines 5-8.

obligation to continue providing safe, reliable and affordable service to its customers that requires continued investment in the gas system.”¹¹⁴² Accordingly, notwithstanding the ongoing Long-Term Planning Rulemaking, the Commission should adopt PG&E’s approach for the continued compliance with federal regulations regarding meter protection.¹¹⁴³

3.7.3.2 Cal Advocates Understates the CGI Population

Cal Advocates recommends zero meter protection CGI (no access) units compared to PG&E’s forecast of 3,410 CGI units for 2023. Cal Advocates bases its recommendation on the actual completion rate for CGIs in 2020, which was very low.¹¹⁴⁴ However, PG&E used historical find data from 2020 (not completions) to determine that 8 percent indicates the level of CGIs PG&E will likely encounter and resolve in the future.¹¹⁴⁵ The forecast is intended to reflect the fact that in 2023 PG&E will target completing more CGIs than in the past to prevent a CGI backlog from growing. PG&E’s approach of using historic find data and not completion data is the correct approach to forecast a 2023 CGI population that will allow the backlog of these types of meter protection to be effectively addressed going forward.¹¹⁴⁶

Cal Advocates’ claim that CGIs are no longer separately tracked and therefore should not be included is simply wrong. Cal Advocates’ does not indicate or cite to the record to support this statement. CGIs are tracked as meter protection attempts are made, and these locations are often more complex and costly to remediate.¹¹⁴⁷ PG&E also mentions the CGI tracker in its workpapers supporting the capital MPP forecast.¹¹⁴⁸

¹¹⁴² PG&E-03, p. 1-8, lines 21-26.

¹¹⁴³ PG&E-16-E, p. 8-26, lines 14-23.

¹¹⁴⁴ PG&E-16-E, p. 8-28, lines 25-26 and fn. 68 (101 CGIs completed in 2020).

¹¹⁴⁵ PG&E-16-E, p. 8-28, lines 12-13.

¹¹⁴⁶ PG&E-16-E, p. 8-29, lines 3-8.

¹¹⁴⁷ PG&E-16-E, p. 8-29, lines 14-18.

¹¹⁴⁸ PG&E-3-ES, WP 8-21.

3.7.3.3 Cal Advocates Understates the Rate of New MPP Finds

Cal Advocates recommends 9,204 New Finds units for 2023, compared to PG&E's forecast of 19,380 New Finds units, a difference of 10,176 units. Cal Advocates recommends its own find rate based on leak surveys and leak repairs performed in 2021 to calculate their recommended 9,204 New Finds units.¹¹⁴⁹ Cal Advocates approach is flawed for two reasons.

First, the total number of New Finds is increasing in comparison to prior years primarily because the frequency of leak survey inspections, where meter protection locations are identified, has increased. PG&E has transitioned from a five-year leak survey cycle to a three-year leak survey cycle aligning both the AC inspection and leak survey compliance plan.¹¹⁵⁰ With the transition of AC inspection to the Leak Survey department, leak surveyors perform both leak survey inspections and AC inspections every three years, instead of every five years. As the number of leak surveys increases the number of new meter protection locations will also increase.¹¹⁵¹

Second, Cal Advocates' methodology relies on actual meter protection units mitigated in 2021 and not on a forecasted find rate.¹¹⁵² As stated for CGIs, PG&E is forecasting to try and address a larger number of MPP units in 2023, and not simply repair at historic rates. Cal Advocates' recommended 9,204 New Finds in 2023 is well below what PG&E expects to encounter in the future and less than what PG&E has identified for remediation in the past.¹¹⁵³ Targeting such a low number of new find units would contribute to more backlog.¹¹⁵⁴

¹¹⁴⁹ CALPA-02, p. 49, lines 4-6.

¹¹⁵⁰ PG&E-03, p. 10- 9, lines 2-4.

¹¹⁵¹ PG&E-16-E, p. 8-30, line 11 to p. 8-31, line 10.

¹¹⁵² PG&E-16-E, p. 8-31, line 13 to p. 8-32 line 1.

¹¹⁵³ PG&E-16-E, PG&E's response to Data Request Cal Advocates_183-Q02Supp01, dated 1/10/22, pp. AppA-347 to AppA-353.

¹¹⁵⁴ PG&E-16-E, p. 8-32, lines 3-9.

3.7.3.4 Cal Advocates Understates MPP Existing Location Units

PG&E's forecast includes steadily working down the existing MPP backlog over the 4-year GRC period based on an estimated 81,133 Existing Locations population today or 20,283 Existing Location units per year.¹¹⁵⁵ Cal Advocates recommends 6,217 Existing Location units per year starting in 2023¹¹⁵⁶ a difference of 14,066 units from PG&E's forecast. Cal Advocates disagrees with PG&E's 81,133 Existing Locations population today and calculates a population of 31,085 Existing Locations.

Cal Advocates' Existing Location calculation is wrong because it fails to include the largest contributor to the existing Meter Back log: meters found through leak survey inspections. PG&E's 81,133 Existing Locations population includes as of June 2020 the Existing Locations (backlog) adjusted for locations identified through AC Inspection, Leak Survey, locations found in the field, and customer call-in locations.¹¹⁵⁷ These all contribute to the total Existing Location backlog that must be addressed in the future. Cal Advocates' forecast methodology uses the Existing (backlog) Locations in PG&E's database (33,814) as of June 2020 and adds only the meters found in the field in 2021. However, MPP meters are discovered not just in the field, but continuously through various means including leak survey inspections. Meters needing protection found through leak survey inspections in 2021 number 51,934 through November 2021¹¹⁵⁸ which was excluded in Cal Advocates' calculations for the backlog forecast. Adding meters found through leak survey inspections to Cal Advocates calculation would result in a higher number of backlog locations than PG&E's forecast backlog locations.¹¹⁵⁹

¹¹⁵⁵ PG&E-16-E, p. 8-33, lines 9-14.

¹¹⁵⁶ CALPA-02, p. 51, lines 9-10.

¹¹⁵⁷ PG&E-16-E, p. 8-33, lines 7-9.

¹¹⁵⁸ PG&E-16-E, PG&E's response to Data Request Cal Advocates_183-Q02Supp01, dated 1/10/22, pp. AppA-347 to AppA-353.

¹¹⁵⁹ PG&E-16-E, p. 8-33, line 22 to p. 8-34, line 4.

Cal Advocates also recommends a remediation pace of five years¹¹⁶⁰ instead of PG&E's four-year forecast pace. Extending the pace of the Existing Locations remediation will result in known locations with the risk of vehicular impact continuing to be unprotected. By performing the necessary work and installing the bollards where needed, customer's gas meters can be protected from the risk of vehicular damage and the potential for gas release. Extending the duration of this remediation will only contribute to further increasing a backlog of work as additional locations are found and added to the meter protection program scope.¹¹⁶¹

3.7.3.5 Cal Advocates Ignores MPP Customer Call In Units

Cal Advocates recommends zero Customer Call-Ins. This recommendation is based on incorrect assumptions. First, PG&E's 2023 forecast of annual customer call-in units (120) was based on approximations of customer generated monthly requests received over the last five years. PG&E's Customer Call-in forecast accounts for emergent work that may require remediation unexpectedly that is outside the routine work flagged during inspections.¹¹⁶²

Second, Cal Advocates incorrectly assumes that PG&E's recorded data over the last five years (2016-2020) shows no meters remediated from Customer Call-Ins. While it is true that customer call-ins were not shown separately in PG&E's data responses, these same responses state that the Customer Call-Ins are shown as part of meters remediated under New Finds. PG&E clarified in the responses that this applies to completed Customer Call In locations, not an indication for future work.¹¹⁶³

¹¹⁶⁰ CALPA-02, p. 51, lines 7-9.

¹¹⁶¹ PG&E-16-E, p. 8-34, lines 7-14.

¹¹⁶² PG&E-16-E, p. 8-35, lines 5-9.

¹¹⁶³ PG&E-16-E, p. 8-35, lines 10-17.

3.7.4 Relocation of Meter Sets – Capital (MAT 27A)

The purpose of the Relocation of Meter Sets Program is two-fold: (1) meter protection through the re-location of the meter set;¹¹⁶⁴ and (2) relocating the meter set due to an inaccessible service valve.¹¹⁶⁵ PG&E forecasts 250 capital units to be completed in 2023.¹¹⁶⁶ TURN is the only party that addresses this program and proposes:

TABLE 3-48
RELOCATION OF METER SETS (MAT 27A): PG&E’S CAPITAL FORECAST AND PARTIES
RECOMMENDED REDUCTIONS (\$000s)^(a)

Party	2020 Rec.	2021	2022	2023	2024	2025	2026
PG&E	\$1,818	\$7,878	\$7,541	\$7,245	\$7,426	\$7,597	\$7,772
TURN				\$(1,921)			
(a) PG&E-16-E, p. 8-41, Table 8-9, line 1 (2020-2022 recorded and forecast amounts); PG&E-3-ES, p. v (2023-2026 forecasts); PG&E-64, p. JCE 3-76 (TURN’s recommendation).							

TURN bases its recommendations on fewer “make up” projects, and forecasts 184 units in 2023, including Inaccessible Valve locations.¹¹⁶⁷ TURN clarified in a data request that it used the term “make-up projects” to reference Existing Locations.¹¹⁶⁸

TURN uses a multiplier of approximately 0.64781 (roughly 65 percent) and applies that to PG&E’s forecast for Capital Meter Protection units and capital CGI units.¹¹⁶⁹ The multiplier represents “the ratio between the total units that PG&E forecast for MAT EXB (43,193) and

¹¹⁶⁴ The type of work performed to remediate a Meter Protection location dictates whether it is capital (MAT 27A) or expense (MAT EXB). PG&E-16-E, p. 8-37, lines 25-27.

¹¹⁶⁵ PG&E-03, p. 8-36, lines 1-4.

¹¹⁶⁶ PG&E’s derivation of the 250 units is set forth at PG&E-16-E, p.8-36, line 5 to p. 8-37, line 3.

¹¹⁶⁷ TURN-06, p. 34, lines 21-23.

¹¹⁶⁸ PG&E-16-E, TURN’s response to PG&E Data Request PGE_TURN007-Q01, dated 6/27/22, pp. AppA-354 to AppA-355.

¹¹⁶⁹ PG&E-16-E, p. 8-37 lines 11-15.

TURN's reduced forecast (27,981)."¹¹⁷⁰ TURN therefore recommends slowing the pace of the capital meter protection program (MAT 27A) to match its recommendation for slowing the pace of the expense meter protection program (MAT EXB).

TURN's proposal should not be adopted. Delaying the meter protection work beyond PG&E's forecast timeframe of 2026 is unreasonable. By performing the necessary meter protection work, customers' gas meters can be protected from the risk of vehicular damage and the potential for gas release. Extending the pace means the meter protection risk will remain unaddressed for a longer period of time.¹¹⁷¹

3.8 Gas Operations Corrosion Control

PG&E-03, Chapter 9 presents PG&E's Corrosion Control Program and the capital and expense forecasts to mitigate the threats of corrosion to PG&E's gas distribution (excluding customer meter sets), transmission, and storage assets. These forecasts are based on PG&E's risk assessment of these threats; and PG&E's plan to reduce these risks.¹¹⁷²

PG&E's Corrected Forecast for GD expense is \$49.328 million. PG&E's JCE forecast is \$52.437.¹¹⁷³ PG&E's JCE forecast is \$52.437 million.¹¹⁷⁴

PG&E's Corrected Forecast for GT&S expense is \$25.907 million. PG&E's JCE forecast is \$29.271 million.¹¹⁷⁵

PG&E's Corrected Forecast for GD capital expenditures is \$34.816 million in 2021, \$36.888 million in 2022, \$21.461 million in 2023, \$21.997 million in 2024, \$22.503 million in

¹¹⁷⁰ PG&E-16-E, TURN's response to PG&E data request TURN007-Q02, dated 6/27/22, p. AppA-355.

¹¹⁷¹ PG&E-16-E, p. 8-37, lines 18-27.

¹¹⁷² PG&E-03, p. 9-1, lines 6-11.

¹¹⁷³ PG&E-64, p. 3-1, Table 3A-1, lines 21-23.

¹¹⁷⁴ PG&E-64, p. 3-1, Table 3A-1, lines 21-23.

¹¹⁷⁵ PG&E-64, p. 3-1, Table 3A-1, lines 24-25.

2025, and \$23.021 million in 2026.¹¹⁷⁶ PG&E’s JCE forecast for capital expenditures is \$36.595 million in 2021, \$40.816 million in 2022, \$24.038 million in 2023, \$23.992 million in 2024, \$23.972 million in 2025, and \$23.933 million in 2026.¹¹⁷⁷

PG&E’s Corrected Forecast for GT&S capital expenditures is \$61.807 million in 2021, \$50.799 million in 2022, \$40.088 million in 2023, \$37.707 million in 2024, \$37.901 million in 2025, and \$38.949 million in 2026.¹¹⁷⁸ PG&E’s JCE forecast for capital expenditures is \$76.295 million in 2021, \$69.933 million in 2022, \$51.109 million in 2023, \$42.830 million in 2024, \$40.871 million in 2025, and \$40.843 million in 2026.¹¹⁷⁹

Of the 27 expense MATs related to Corrosion Control, only 2 are disputed. Similarly, for the 11 capital MATs, 4 are disputed. The undisputed programs, associated MATs, and corresponding expense and capital forecasts are identified in Appendix A. In the remainder of this Section 3.8, we address the following disputed programs:

**TABLE 3-49
SUMMARY OF ISSUES ADDRESSED IN SECTION 3.8**

Section	Disputed Program	Impacted MATs
3.8.1	GD Atmospheric Corrosion Mitigation – Mains	Expense (MAT FHL)
3.8.2	GD Atmospheric Corrosion Mitigation – Services	Expense (MAT FHM)
3.8.3	GD Capital Corrosion Control	Capital (MATs 50D/50Q)
3.8.4	GT&S Corrosion Control Capital Expenditures	Capital (MAT 3K1, 3K4, 3K9)

¹¹⁷⁶ PG&E-16-E, p. 9-26, Table 9-9, line 3 (2021 and 2022) and PG&E-3-ES, p. v, which reflects PG&E’s rebuttal forecast updated with corrected escalation factors. (2023-2026).

¹¹⁷⁷ PG&E-64, p. 3-6, Table 3B-1, line 16 (2023); p. 3-10, Table 3B-2, line 16 (2022); and p. 3-14, Table 3B-3, line 16 (2021). The 2024-2026 forecasts are not included in the JCE but are provided here for reference.

¹¹⁷⁸ PG&E-16-E, p. 9-26, Table 9-10, line 9 (2021 and 2022) and PG&E-3-ES, p. v, which reflects PG&E’s rebuttal forecast updated with corrected escalation factors. (2023-2026).

¹¹⁷⁹ PG&E-64, p. 3-6, Table 3B-1, line 15 (2023); p. 3-10, Table 3B-2, line 15 (2022); and p. 3-14, Table 3B-3, line 15 (2021). The 2024-2026 forecasts are not included in the JCE but are provided here for reference.

Section	Disputed Program	Impacted MATs
3.8.5	The Internal Corrosion Balancing Account (ICBA)	N/A

3.8.1 GD Atmospheric Corrosion Mitigation – Mains (MAT FHL)

GD Atmospheric Corrosion Mitigation – Mains mitigates deficient coating systems identified during atmospheric corrosion inspections of steel distribution main spans. Typical mitigation projects include coating repair or coating replacement.¹¹⁸⁰ PG&E is forecasting to spend \$3.2 million in 2023 to mitigate 145 GD Main spans that were identified during 2020 atmospheric corrosion inspections. PG&E forecast the 2023 unit cost for MAT FHL by using the average unit cost from 2018-2020, escalated. The forecast represents an increase of approximately \$2.7 million compared to 2020 recorded costs¹¹⁸¹ and an increase of 117 spans compared to 2020 recorded units.¹¹⁸² The increase in forecast units and dollars, as compared to 2020, is primarily due to the discovery of additional spans from the 2020 Atmospheric Corrosion Span Inspection Project (MAT FHK). Cal Advocates is the only party that addresses this program and proposes:

TABLE 3-50
GD ATMOSPHERIC CORROSION MITIGATION - MAINS (MAT FHL): PG&E'S EXPENSE FORECAST AND PARTIES RECOMMENDED REDUCTIONS (\$000s)^(a)

Party	2020 Rec.	2021	2022	2023
PG&E	\$498	\$2,000	\$3,591	\$3,184
Cal Advocates				\$(1,975)
(a) PG&E-16-E, p. 9-25, Table 9-7, line 12 (2020-2023 recorded and forecast amounts); PG&E-16-E, p. 9-4, Table 8-1, line 9 (Cal Advocates' recommendation).				

Cal Advocates' recommended reduction is based on: (1) the assertion that "PG&E has not adequately supported the significant increase in the number of main mitigation projects in

¹¹⁸⁰ PG&E-03, p. 9-27, lines 1-18.

¹¹⁸¹ PG&E-03, p. 9-27, lines 14-18.

¹¹⁸² A.18-12-009, PG&E GD Pipeline Safety Report No. 2020, p. 28, Table 7-1, line 51.

2023 due to an increase in the number of spans discovered in 2020”¹¹⁸³ and (2) a revised unit cost of \$11,231 based on a 2021 partial year.¹¹⁸⁴

Cal Advocates derived its recommended 2023 mitigation rate (15 percent) by dividing the number of 2021 main span mitigations (78) by the number of 2021 main span inspections (519).¹¹⁸⁵ Cal Advocates then applied their recommended 2023 mitigation rate (15 percent) to PG&E’s 2023 forecast of 461 atmospheric corrosion inspections under MAT FHK to provide a total of 108 mitigation projects in 2023.¹¹⁸⁶ Cal Advocates forecast of 108 mitigation projects in 2023 is too low for several reasons.

First, Cal Advocates’ recommended mitigation rates¹¹⁸⁷ are calculated using same year inspection and mitigation units (i.e., 2021 span remediation projects/2021 span inspections). However, in accordance with PHMSA guidance, the vast majority of PG&E’s atmospheric corrosion remediation projects occur in the third year following the atmospheric corrosion inspections (i.e., 2023 span remediation projects were identified during 2020 span inspections).¹¹⁸⁸ Cal Advocates calculated mitigation rates are therefore not indicative of the actual find rate of GD spans that required remediation during the period 2018-2021 and should not be utilized to forecast future work.¹¹⁸⁹

¹¹⁸³ CALPA-02, p. 58, lines 16-18.

¹¹⁸⁴ CALPA-02, p. 60, lines 2-4. PG&E cannot duplicate the calculation utilized by Cal Advocates to provide \$1.209 million ($108 \times \$11,231 \neq \$1.209$ million).

¹¹⁸⁵ CALPA-02, p. 59, Table 2-45.

¹¹⁸⁶ CALPA-02, p. 60, lines 1-4. PG&E cannot duplicate the calculation utilized by Cal Advocates to provide 108 projects ($461 \times 15\% \neq 108$).

¹¹⁸⁷ CALPA-02, p. 58, Table 2-44.

¹¹⁸⁸ PG&E-03, p. WP 9-48.

¹¹⁸⁹ PG&E-16-E, p. 9-10, line 15 to p. 9-11, line 4.

Second, Cal Advocates acknowledges that PG&E identified an additional 532 spans following a records research project¹¹⁹⁰ but does not consider the impact of this effort in its unit forecast. PG&E's 2023 forecast for MAT FHL is based on the actual number of spans identified for remediation during 2020 atmospheric corrosion inspections and planned for remediation in 2023.¹¹⁹¹

Third, Cal Advocates' recommendation is based on 2021 recorded data that was not available when PG&E submitted its 2023 GRC. PG&E's forecast excludes 2021 recorded costs and is based on information that was known or available when PG&E's forecast was developed in March 2021 in accordance with the Commission's Rate Case Plan.¹¹⁹² The use of 2021 recorded data in this GRC is further discussed in Section 1.5 of this opening brief.

With regard to the issue of unit costs, PG&E's 2023 unit cost forecast of \$21,961 is based on the average unit cost for this work stream for the period 2018-2020, escalated to 2023.¹¹⁹³ The use of a 3-year average unit cost is the appropriate methodology to calculate representative unit costs over time and considers year-to-year cost variations associated with projects completed across PG&E's service territory.¹¹⁹⁴

Cal Advocates recommends utilization of a calculated 2021 unit cost (\$11,231) without escalation for 2023.¹¹⁹⁵ Cal Advocates calculated this cost by dividing the January – November 2021 costs (\$876,000) by the total 2021 units (78).¹¹⁹⁶ Dividing partial year costs by full year units is wrong on its face. Further, this approach provides a value that is significantly lower

¹¹⁹⁰ CALPA-2, p. 58, lines 13-15.

¹¹⁹¹ PG&E-16-E, p. 9-11, lines 5-12.

¹¹⁹² PG&E-16-E, p. 9-11, lines 13-17.

¹¹⁹³ PG&E-03, WP 9-16, lines 3-10.

¹¹⁹⁴ PG&E-16-E, p. 9-11, line 18 to p. 9-12, line 2.

¹¹⁹⁵ CALPA-02, p. 59, lines 22-26.

¹¹⁹⁶ CALPA-02, p. 59, Table 2-45.

(~55 percent) than the average of 2018-2020 unit costs adjusted to 2021 dollars.¹¹⁹⁷ This is not sound forecasting practice and should be rejected by the Commission.

3.8.2 GD Atmospheric Corrosion Mitigation – Services (MAT FHM)

GD Atmospheric Corrosion Mitigation - Services mitigates deficient coating systems identified during atmospheric corrosion inspections of steel service spans and service risers. Typical mitigation projects include coating repair or coating replacement. In instances where significant corrosion is encountered, replacement of service risers may also be performed. PG&E is forecasting \$1.6 million in 2023 to mitigate 1,822 standard historic units (coating repair, coating replacement, and riser replacement) and an additional \$10.7 million to mitigate 55,000 new units associated with expanded remediation requirements for service risers at the soil-to-air interface.^{1198, 1199} PG&E's unit forecast for service riser coating remediation at the soil-to-air interface, 55,000 units, was based on an engineering estimate of a five percent find rate applied to PG&E's approximate 1.1 million annual service riser inspections.¹²⁰⁰ Cal Advocates is the only party that addresses this program and proposes:

¹¹⁹⁷ PG&E-03, WP 9-16, line 10 provides a 2021 unit cost of \$20,562.79. ($\$11,231 / \$20,562.79 = \sim 0.55$).

¹¹⁹⁸ In 2017, PG&E standardized the atmospheric corrosion inspection of main and service spans including a more rigorous inspection of the soil to air transition zone per 49 CFR 192, Subpart I requirements, along with a requirement to mitigate any wrap damage in that zone. In 2021, the inspection of soil to air transitions at service risers became more rigorous, and the subsequent repair of wrap damage was expanded to include said risers. PG&E-03, p. 9-28, lines 12-19.

¹¹⁹⁹ PG&E-03, WP 9-17, WP Table 9-15, lines 13-16.

¹²⁰⁰ PG&E-16-E, PG&E's response to Data Request CalAdvocates_235-Q002, dated 2/2/22, pp. AppA-359 to AppA-360.

TABLE 3-51
GD ATMOSPHERIC CORROSION MITIGATION – SERVICES (MAT FHM): PG&E’S
EXPENSE FORECAST AND PARTIES RECOMMENDED REDUCTIONS (\$000s)^(a)

Party	2020 Rec.	2021	2022	2023
PG&E	\$1,168	\$997	\$11,565	\$12,272
Cal Advocates				\$(8,348)
(a) PG&E-16-E, p. 9-25, Table 9-7, line 13 (2020-2023 recorded and forecast amounts); PG&E-16-E, p. 9-4, Table 8-1, line 10 (Cal Advocates’ recommendation).				

Cal Advocates’ recommended 2023 forecast is based on PG&E’s January-November 2021 recorded expense “adjusted to include the month of December estimated at \$327,000 (1/11th of [\$3.6] million) for 24,366 service riser repairs.”¹²⁰¹ Cal Advocates’ proposed reduction is based on the assertion that PG&E “failed to adequately justify the significant increase in the [t]est [y]ear... .”¹²⁰² Cal Advocates asserts that the unit counts for the period 2019-2021 provided by PG&E shows that the number of service risers identified for corrective action does not support the 55,000 service riser repair forecast. Cal Advocates’ forecast is flawed for several reasons.

First, Cal Advocates incorrectly assumes that PG&E’s 2021 recorded costs are representative of future years and should be the sole basis for 2023 funding recommendations. However, the 2021 recorded costs do not represent a full year of service riser remediation at the soil to air interface. Moreover, PG&E did not implement the expansion of service riser remediation requirements to include coating damage at the soil to air interface until March 2021.¹²⁰³ Thus, the 2021 unit performance does therefore not reflect future years where the required work is known in advance and distributed over a full 12-month period.

Second, PG&E’s 2023 forecast, which was submitted on June 30, 2021, is based on information that was known on or before March 2021, in accordance with Commission guidance

¹²⁰¹ CALPA-02, p. 56, lines 3-6.

¹²⁰² CALPA-02, p. 55, lines 19-22.

¹²⁰³ PG&E-16-E, p. 9-14, lines 24-30.

for forecast ratemaking. PG&E's forecast utilized an engineering estimate to determine the number of service risers that would require repair due to damaged coating at the soil-air interface, as this was a new activity that started in 2021. Cal Advocates' asserts that PG&E's forecast based on an engineering estimate of the volume of work associated with a new activity is flawed; however, this assertion is based on 2021 recorded data that was not available when PG&E's forecast was developed.¹²⁰⁴

Finally, Cal Advocates' recommendation to adopt the 2021 adjusted recorded expense amount of \$3.9 million for 2023 does not provide for standard annual cost escalation.¹²⁰⁵ For all these reasons, the Commission should adopt PG&E's forecast.

3.8.3 GD Capital Corrosion Control (MATs 50D/50Q)

GD Capital Corrosion Control includes the following work activities: Rectifier Replacements (MAT 50D); Capital Coating Remediation of Spans > 100 feet (MAT 50D); and GD Capital Contacted Casing Remediation of Casings > 100 feet (MATs 50D/50Q).¹²⁰⁶ PG&E's GD Capital Casing Mitigation forecast for MAT 50D/50Q is \$15.3 million in 2021 and \$19.5 million in 2022.¹²⁰⁷ No party disputed PG&E's forecast for 2023 and beyond.

Cal Advocates recommends that PG&E's 2021 GD Capital Casing Mitigation forecast for MAT 50D/50Q, \$15.3 million, be reduced by \$4.5 million to \$10.9 million; and that the PG&E's 2022 forecast, \$19.5 million, be reduced by \$8.7 million to \$10.9 million. Cal Advocates' recommended 2021 and 2022 capital forecasts are based on PG&E's

¹²⁰⁴ PG&E-16-E, p. 9-14, lines 14-23.

¹²⁰⁵ PG&E-16-E, p. 9-15, lines 8-13.

¹²⁰⁶ See PG&E-03, p. 9-19, lines 15-21 and p. 9-24, line 16 to p. 9-25, line 5 (MAT 50D - Rectifiers); p. 9-25, line 6 to p. 9-29, line 12 (MAT 50D - Atmospheric); and p. 9-30, lines 9-16 (MATs 50D/50Q - Casings). Mitigation of contacted casings greater than 100 feet was historically recorded to MAT 50D; however, this work transitioned to a new/dedicated MAT 50Q on January 1, 2021.

¹²⁰⁷ PG&E-16-E, p. 9-26, Table 9-9, line 1.

January-November 2021 recorded expense to MAT 50D/50Q adjusted to include the month of December estimated at \$904,000 (1/11th of \$10.0 million).¹²⁰⁸

With regard to the 2021 capital forecast, Cal Advocates' recommendation is flawed for two reasons. First, the use of 2021 recorded data in this rate case is inappropriate because it predates PG&E's filing.¹²⁰⁹ The use of 2021 recorded data in this GRC is further discussed in Section 1.5 of this brief.

Second, even if the Commission adopts 2021 recorded to replace PG&E's forecast, Cal Advocates failed to use the full 2021 data provided by PG&E on March 9, 2022, more than 90 days prior to Cal Advocates' submission of its testimony.¹²¹⁰ The actual 2021 recorded cost for MATs 50D/50Q was \$12.3 million. This total includes \$11.3 million for GD Capital Casing Mitigation that was recorded to MAT 50Q and \$1.0 million for GD Capital Corrosion Control (Rectifiers and Atmospheric Coatings) that was recorded to MAT 50D.¹²¹¹ Cal Advocates' recommendation to adopt the 2021 adjusted November 30, 2021-recorded capital expenditures of \$10.9 million for 2021 and 2022, does not represent actual 2021 recorded data.¹²¹²

With regard to the 2022 capital forecast, PG&E's 2022 combined forecast for MATs 50D/50Q, \$19.5 million, includes approximately \$18.2 million for GD Capital Casing Mitigation.¹²¹³ Cal Advocates proposes reducing this forecast to \$10.9 million based on 2021 actuals. This approach ignores the fact that PG&E forecasted completion of all backlog GD Capital Casing Mitigation projects in 2022 and the transition of the program to find it/fix it in

¹²⁰⁸ CALPA-02, p. 63, lines 19-24.

¹²⁰⁹ PG&E-16-E, p. 9-17, lines 16-19.

¹²¹⁰ PG&E-16-E, p. 9-17, lines 20-26.

¹²¹¹ PG&E-16-E, p. 9-17, lines 6-10.

¹²¹² PG&E-16-E, p. 9-16, line 26 to p. 9-17, line 2.

¹²¹³ PG&E-16-E, p. 9-19, lines 3-4.

2023.¹²¹⁴ Reducing the backlog will increase the program costs in 2022. Cal Advocates' recommendation would effectively place a cap on 2022 funding for GD Capital Casing Mitigation and result in projects being delayed until future years. PG&E's 2023-2026 forecast for GD Capital Casing Mitigation is based on the discovery and mitigation of ten casings per year¹²¹⁵ and does not account for carry-over casings that would be created by Cal Advocates' recommendation to reduce funding for GD Capital Casing Mitigation, MAT 50Q, in 2022.

Cal Advocates further justifies its recommended 2021 and 2022 adjusted recorded capital forecasts of \$10.9 million by claiming that "with the exception of 2019, PG&E's recorded annual capital expenditures from 2016-2020" and January-November 2021 were \$10 million or less.¹²¹⁶ This comparison is inappropriate. PG&E's 2016-2020 recorded spend for MAT 50D includes multiple work streams including Capital Casing Remediation, RMU Installations, Rectifier Installations, and Atmospheric Corrosion Remediation.¹²¹⁷ Cal Advocates incorrectly assumes that the total combined spend of all work streams in MAT 50D are related to Capital Casing Remediation.¹²¹⁸ Moreover, PG&E's GD Capital Casing Mitigation program began in 2017 and continued as a developmental program through 2019. PG&E utilized the information obtained during the 2017-2019 developmental program to develop the GD Capital Casing Mitigation program presented in the 2020 GRC. The use of 2016 recorded expenditures for MAT 50D to forecast PG&E's 2022 GD Capital Casing Mitigation (MAT 50Q) expenditures is therefore inappropriate, as the GD Capital Casing Mitigation program did not exist until 2017. Moreover, using 2017-2019 total recorded expenditures fails to recognize the transition of this

¹²¹⁴ PG&E-03, p. 9-31, line 24 to p. 9-32, line 3.

¹²¹⁵ PG&E-3-ES, p. WP 9-89, lines 11 and 19.

¹²¹⁶ CALPA-02, p. 63, lines 1-8.

¹²¹⁷ Capital RMU Installations and Atmospheric Corrosion Remediation were not forecast in the 2023 GRC. PG&E-16-E, p. 9-18, fn. 38.

¹²¹⁸ PG&E-16-E, p. 9-18, lines 5-7.

program from developmental in the 2017 GRC (2017-2019) to full scale in the 2020 GRC (2020-2022). Thus, using recorded costs for 2016, when the Casing Mitigation program did not exist, and 2017-2019 data (when the Casings Mitigation program was being developed) does not provide a reasonable basis to forecast the program in 2022.¹²¹⁹

Finally, Cal Advocates' assertion that PG&E repeatedly underspends Commission-authorized capital expenditure funding for casing mitigation¹²²⁰ does not support its recommendation to reduce PG&E's 2022 forecast for GD Capital Casing Mitigation. Cal Advocates presents data from PG&E's GT&S Capital Casing program (MAT 3K5) but provides no explanation as to why historic GT&S spends from MAT 3K5 support their 2022 recommendation for GD Capital Casing Mitigation (MAT 50Q).¹²²¹

3.8.4 GT&S Corrosion Control Capital Expenditures (MAT 3K1, 3K4, 3K9)

PG&E's GT&S Capital Corrosion Control programs included MATs 3K1, 3K4, and 3K9. PG&E's forecast for 2021 for these programs are shown in parentheses: MAT 3K1, Internal Corrosion Program (\$12.0 million); MAT 3K4 AC Interference Program (\$11.7 million); and MAT 3K9, DC Interference Program (\$10.4 million).¹²²² No party challenged PG&E's 2022 or 2023 forecasts for these programs.

Cal Advocates proposes that PG&E's 2021 forecasts for these three MAT codes be replaced by January-November 2021 recorded expense.¹²²³ This results in a 2021 GT&S Capital Internal Corrosion Mitigation forecast for MAT 3K1 of \$1.4 million; a 2021 GT&S Capital AC Interference forecast for MAT 3K4 of \$3.4 million; and a 2021 GT&S Capital DC Interference forecast for MAT 3K9, of \$6.8 million.

¹²¹⁹ PG&E-16-E, p. 9-18, lines 9-21.

¹²²⁰ CALPA-02, p. 63, lines 9-13.

¹²²¹ PG&E-16-E, p. 9-18, lines 22-29.

¹²²² PG&E-16-E, p. 9-20, lines 7-13.

¹²²³ PG&E-16-E, p. 9-20, lines 7-13.

Cal Advocates' recommendation to replace PG&E's 2021 forecast with November 30, 2021 recorded capital expenditures should be rejected. Cal Advocates is using 2021 data that was not available when PG&E submitted its 2023 GRC application. PG&E's forecast excludes 2021 recorded costs and is based on information that was known or available when PG&E's forecast was developed in March 2021 in accordance with the Commission's Rate Case Plan. Cal Advocates' proposal to replace PG&E's 2021 forecast with 2021 recorded financials is addressed in more detail in Section 1.5 of this brief.¹²²⁴

3.8.5 The Internal Corrosion Balancing Account (ICBA)

The ICBA is addressed in Section 3.14.3.2 of this opening brief.

3.9 Gas Operations Leak Management

PG&E's Leak Management programs consist of gas leak surveys and leak grading, gas leak repairs, and gas service and main replacements when needed to remediate gas leaks. PG&E's Leak Management programs mitigate safety and reliability risks on the gas distribution system, and the GT&S system, as well as reducing GHG emissions. In 2020, PG&E's Leak Management teams surveyed over 1.4 million gas distribution services and over 13,000 miles of transmission pipeline, identified 26,513 gradable distribution gas leaks and 4,012 gradable GT&S gas leaks and repaired 21,251 gradable distribution gas leaks and 3,503 gradable GT&S gas leaks.¹²²⁵

PG&E's Corrected Forecast for GD expense is \$127.313 million.¹²²⁶ PG&E's JCE forecast is \$137.959 million.¹²²⁷

¹²²⁴ PG&E-16-E, p. 9-21, lines 12-20.

¹²²⁵ PG&E-03, p. 10-1, lines 6-19.

¹²²⁶ PG&E-16-E, p. 10-3, Table 10-1, line 18.

¹²²⁷ PG&E-64, p. 3-1, Table 3A-1, lines 26, 27 and 30.

PG&E's Corrected Forecast for GT&S expense is \$22.445 million.¹²²⁸ PG&E's JCE forecast is \$24.032 million.¹²²⁹

PG&E's Corrected Forecast for GD capital expenditures is \$27.518 million in 2021, \$28.083 million in 2022, \$22.687 million in 2023, \$23.201 million in 2024, \$24.220 million in 2025, and \$25.019 million in 2026.¹²³⁰ PG&E's JCE forecast is \$28.924 million in 2021, \$31.074 million in 2022, and \$25.412 million in 2023, \$25.305 million in 2024, \$25.801 million in 2025, and \$26.010 million in 2026.¹²³¹

Of the 23 expense MATs related to Gas Operations Leak management, only 3 are disputed. Similarly, for the 5 gas distribution capital MATs, only 1 is disputed. The undisputed programs, associated MATs, and corresponding expense and capital forecasts are identified in Appendix A. In the remainder of this Section 3.9, we address the following disputed programs:

TABLE 3-52
SUMMARY OF ISSUES ADDRESSED IN SECTION 3.9

Section	Disputed Program or Balancing/Memorandum Account	Impacted MATs
3.9.1	Below Ground Distribution Main Leak Repair	Expense (MAT FIG)
3.9.2	Distribution Meter Set Leak Repair	Expense (MAT FIS)
3.9.3	Below Ground Distribution Service Replacement	Capital (MAT 50G)
3.9.4	Transmission Leak Repair	Expense (MAT JOP)
3.9.5	New Environmental Regulations Balancing Account (NERBA)	N/A

¹²²⁸ PG&E-3-ES, p. iii, which reflects PG&E's rebuttal forecast updated with corrected escalation factors.

¹²²⁹ PG&E-64 p. 3-1, Table 3A-1, lines 28-29.

¹²³⁰ PG&E-16-E, p. 10-31, Table 10-7, line 9 (2021 and 2022) and PG&E-3-ES, p. v, which reflects PG&E's rebuttal forecast updated with corrected escalation factors. (2023-2026).

¹²³¹ PG&E-64, p. 3-6, Table 3B-1, lines 17-19 (2023); p. 3-10, Table 3B-2, lines 17-19 (2022); and p. 3-14, Table 3B-3, lines 17-19 (2021). Forecasts for 2024-2026 are not included in the JCE but are provided here for reference.

3.9.1 Below Ground Distribution Main Leak Repair (MAT FIG)

Below Ground Distribution Main Leak Repair is the work to repair leaks on gas distribution mains. PG&E's main leak repair complies with the work required by federal regulations.¹²³² PG&E's 2023 forecast for this program is \$33.7 million.¹²³³ Cal Advocates is the only party that addresses this program and proposes:

TABLE 3-53
BELOW GROUND DISTRIBUTION MAIN LEAK REPAIR (MAT FIG): PG&E'S EXPENSE FORECAST AND PARTIES RECOMMENDED REDUCTIONS (\$000s)^(a)

Party	2020 Rec.	2021	2022	2023
PG&E	\$25,526	\$33,987	\$35,776	\$33,715
Cal Advocates				\$(7,405)

(a) PG&E-16-E, p. 10-30, Table 10-5, line 10 (2020-2023 recorded and forecast amounts); PG&E-16-E, p. 10-3, Table 10-1, line 9 (Cal Advocates' recommendation).

Cal Advocates' recommendation is based on a lower leak find rate and a lower unit cost per repair than PG&E's forecast.¹²³⁴ These two issues are addressed below.

3.9.1.1 PG&E's Leak Find Rate is Reasonable

PG&E determined a 2.04 percent leak find rate for below ground leaks using the following analysis. PG&E's leak "find rate per 1 thousand services surveyed" for each leak grade are based on a blend of 2018-2020 June YTD actuals broken down by Division.¹²³⁵ Using these find rates, PG&E forecast the leak find volume in 2023 for each type of leak – above ground grade 1, 2 and 3 leaks and below ground grade 1, 2 and 3 leaks. PG&E then added the forecast call-in leaks found from customer odor complaints. Finally, PG&E summed up the leaks forecast from these calculations and obtained a total 2023 forecast leak volume of

¹²³² PG&E-03, p. 10-29, line 19 to p. 10-30, line 9.

¹²³³ PG&E-16-E, p. 10-3, Table 10-1, line 9. This forecast is net of a \$12.7 million errata reduction that is explained in PG&E-16-E, p. 10-8, lines 11-19.

¹²³⁴ CALPA-02, p. 74, lines 9-16.

¹²³⁵ PG&E-03, WP 10-39, Workpaper Table 10-34, fn. A.

27,739.¹²³⁶ This total, divided by the total leak survey volume of 1,361,716 units, yields PG&E's overall find rate of 2.04%.

Cal Advocates' 0.84 percent leak find rate is based on 11,405 (total leaks found in 2021 as of November 30, 2021), divided by 1,351,684 (total number of services surveyed in 2021).¹²³⁷ Cal Advocates' assumptions and approach are flawed for the following reasons.

First, Cal Advocates based its 2023 forecast calculation on 11 months' worth of 2021 leak data (as of November 30, 2021) and therefore understates the find rate. In addition, Cal Advocates based its forecast calculation on 2021 recorded, while PG&E's forecast was finalized in March 2021 and was based on the data available through 2020.¹²³⁸

Second, by utilizing a single year for its forecast calculation, Cal Advocates' recommendation only provides leak rate information for one third of PG&E's gas distribution system because PG&E's leak survey covers the entire system every three years and is not a true representation of a legitimate historical average find rate.¹²³⁹

Finally, Cal Advocates' leak find rate does not include a volume of leaks found due to Call-ins from customer odor complaints, which is included in PG&E's 2023 forecast.¹²⁴⁰

3.9.1.2 PG&E's 2023 Forecasted Unit Cost Is Reasonable

PG&E's 2023 forecasted unit cost for leak repairs is based on 2020 recorded costs plus a 3.75 percent escalation due to annual Internal Brotherhood of Electrical Workers (IBEW) wage

¹²³⁶ These steps are all set forth in PG&E-03, WP 10-33, Workpaper Table 10-28, lines 1-10.

¹²³⁷ CALPA-2, p. 75, Table 2-60.

¹²³⁸ PG&E-16-E, p. 10-10, lines 1-5.

¹²³⁹ PG&E-16-E, p. 10-10, lines 6-10.

¹²⁴⁰ PG&E-03, WP 10-44, Table 10-36.

increases.¹²⁴¹ Cal Advocates' unit cost is based on 2021 recorded costs divided by 2021 recorded leak repairs as of November 30, 2021.¹²⁴²

The Commission should adopt PG&E's unit cost and reject Cal Advocates' proposal. First, as stated above, Cal Advocates' approach is not based on a full year's data, but instead uses a 2023 forecast calculation based on 11 months' worth of 2021 repairs and costs (as of November 31, 2021). Second, Cal Advocates uses 2021 data which was not available at the time of filing. This is inconsistent with the base year of 2020 recorded costs used in accordance with the Commission's Rate Case Plan. The use of 2021 recorded data in this GRC is further discussed in Section 1.5 of this opening brief. Finally, Cal Advocates' unit cost does not include the 3.75 percent escalation to account for the IBEW annual wage increase.¹²⁴³

3.9.2 Distribution Meter Set Leak Repair (MAT FIS)

Meter Set Leak Repair is the work to repair non-hazardous leaks on gas meter sets.¹²⁴⁴ PG&E forecasts 139,749 meter repairs in 2023 at a total forecasted expense of \$16.2 million.¹²⁴⁵ Repair of non-hazardous meter set leaks within 36 months is required pursuant to PG&E's internal Work and Compliance Matrix.¹²⁴⁶ Cal Advocates is the only party that addresses this program and proposes:

¹²⁴¹ PG&E-03, WP 10-47, lines 13-26.

¹²⁴² CALPA-2, p. 79, lines 19-21 and p. 80, Table 2-63.

¹²⁴³ PG&E-16-E, p.10-11, lines 17-24.

¹²⁴⁴ PG&E-03, p. 10-30, line 12 to p. 10-31, line 4.

¹²⁴⁵ PG&E-16-E, p. 10-12, lines 20 and 26.

¹²⁴⁶ PG&E-03, p. 10-30, lines 19-22.

TABLE 3-54
DISTRIBUTION METER SET LEAK REPAIR (MAT FIS): PG&E’S EXPENSE FORECAST
AND PARTIES RECOMMENDED REDUCTIONS (\$000s)^(a)

Party	2020 Rec.	2021	2022	2023
PG&E	\$6,952	\$10,166	\$10,031	\$16,209
Cal Advocates				\$(8,673)
(a) PG&E-16-E, p. 10-30, Table 10-5, line 17 (2020-2023 2020-2023 recorded and forecast amounts); PG&E-16-E, p. 10-3, Table 10-1, line 16 (Cal Advocates’ recommendation).				

Cal Advocates recommendation is based on a lower number of repair units and a lower unit cost per repair compared to PG&E’s proposal.¹²⁴⁷

3.9.2.1 PG&E’s Forecasted Units Are Reasonable

PG&E used historical average find rates from 2018 to 2020 YTD June plus an additional 10 percent to address pending units to achieve a target of approximately 70,000 pending units by the end of this rate case cycle. Pending units represent the backlog of units left open at the end of a given year.¹²⁴⁸ PG&E determined a 9.48 percent leak find rate (*i.e.*, number of expected leaks on services surveyed) based on a combination of meter set leaks at 8.08 percent and riser thread leaks at 1.4 percent. The meter set leak find rate is based on a three-year average (2018-2020 YTD June) of recorded finds divided by total services leak surveyed.¹²⁴⁹ The riser thread leaks find rate is based on a blended leak find rate from 2018-2020 YTD June adjusted to account for a 2020 change to PG&E’s Leak Grading procedure which reallocated riser thread leaks as non-gradable leaks.¹²⁵⁰

Cal Advocates’ method for calculating a lower 7.4 percent leak find rate is based on the total number of meter set leak finds divided by the total number of services surveyed as of

¹²⁴⁷ CALPA-02, p. 85, Table 2-68.

¹²⁴⁸ PG&E-16-E, p. 10-13, lines 7-13.

¹²⁴⁹ PG&E-03, WP 10-58, lines 1-5.

¹²⁵⁰ PG&E-16-E, p. 10-13, lines 16-27.

November 30, 2021.¹²⁵¹ Cal Advocates combined repair rate of 68.48 percent is based on a 59.94 percent meter set repair rate plus an 8.54 percent riser thread leak repair rate, which is based on the 2021 recorded repair and leak survey data as of November 30, 2021.¹²⁵²

The Commission should approve PG&E's unit forecast of 139,749 units and reject Cal Advocates' unit forecast of 69,285 for the following reasons.¹²⁵³ First, Cal Advocates' proposal is not an accurate representation of the leak finds year over year. Cal Advocates' recommendation is based on a single year of data and does not align with PG&E's three-year compliance survey. Cal Advocates therefore only accounts for a portion of the system. The conditions of the survey areas within each year vary, thus resulting in different leak find rates. These conditions include different pipe age, material, and environmental factors such as soil conditions and location within the service territory. As a result, a single year find and repair rate is not representative of the true, average historical find rate. By contrast, PG&E's find and repair rates are based on a three-year average (2018 to 2020 YTD June).

Second, Cal Advocates' unit forecast would allow the pending meter set leak volume to continue to grow year over year where PG&E's proposed forecast would allow PG&E to repair the volume of annual leak finds and meet the Company's objective of a steady state backlog of approximately 70,000 pending non-hazardous meter set leaks.¹²⁵⁴ PG&E seeks to repair non-gradable leaks within a 36-month time frame as required by PG&E's Work and Compliance Matrix.¹²⁵⁵ If PG&E only repairs Cal Advocates' recommended units of 69,285 versus the 139,749 forecasted, the pending backlog of meter set leaks could reach over 400,000 by the end

¹²⁵¹ CALPA-02, p. 82, Table 2-65.

¹²⁵² CALPA-02, p. 85, Table 2-68.

¹²⁵³ PG&E-16-E, p. 10-15, line 5 to p. 10-16, line 7.

¹²⁵⁴ PG&E-03, p. 10-30, lines 15-19.

¹²⁵⁵ PG&E-03, p. 10-30, lines 19-22.

of the rate case cycle.¹²⁵⁶ In addition, by 2026, PG&E would be performing repairs in the same year as they are due, potentially leaving approximately 40,000 units overdue after repairing Cal Advocates' recommended 69,285 units.

Finally, PG&E's Leak Grading procedure was updated in March 2020 which reallocated riser thread leaks as non-gradable leaks, now captured under MAT FIS. Thus, using a six-year average proposed by Cal Advocates to forecast the number of riser thread leaks¹²⁵⁷ would not be an accurate representation of the program and would under-forecast the number of riser leaks because starting March 2020 those leaks were excluded from MAT FIH.

3.9.2.2 PG&E's 2023 Forecasted Unit Cost Is Reasonable

PG&E's 2023 forecasted unit cost is based on a combination of costs to repair meter set leaks, and cost to repair riser thread leaks, broken down by Field Services and Maintenance & Construction (M&C).¹²⁵⁸ Meter set leak repair costs are based on 2019, not 2020, recorded data due to the impacts on 2020 costs caused by job delays due to State-mandated COVID restrictions. Riser thread repair costs are calculated separately because cost per unit is higher due to some of the repairs requiring M&C repair support and are based on a 2018-2020 YTD June historical average.¹²⁵⁹ Cal Advocates' unit cost is based on 2021 recorded costs of meter set repairs divided by 2021 recorded leak repairs (both as of November 30, 2021) and similarly for riser thread leaks.¹²⁶⁰

Cal Advocates' approach is flawed because it does not take into consideration a full years' work, meaning the 2021 recorded data used was as of November 31, 2021. Also, Cal Advocates uses 2021 data which was not available at the time PG&E filed on June 30, 2021.

¹²⁵⁶ See PG&E-03, WP 10-58 to WP 10-60, lines 74-100.

¹²⁵⁷ CALPA-02, p. 87, lines 14-16.

¹²⁵⁸ See PG&E-03, WP 10-62, WP Table 10-51.

¹²⁵⁹ PG&E-16-E, p. 10-16, lines 18-26.

¹²⁶⁰ PG&E-16-E, p. 10-17, lines 1-3.

This is inconsistent with the base year of 2020 recorded costs used in accordance with the Commission’s Rate Case Plan.¹²⁶¹ The use of 2021 recorded data in this GRC is further discussed in Section 1.5 of this brief.

3.9.3 Below Ground Distribution Service Replacement (MAT 50G)

Simple service replacement is the work to replace or deactivate entire or stub services due to leaks and complies with federal regulations.¹²⁶² Cal Advocates is the only party that addresses this program and proposes:

TABLE 3-55
BELOW GROUND DISTRIBUTION SERVICE REPLACEMENT (MAT 50G): PG&E’S
CAPITAL FORECAST AND PARTIES RECOMMENDED REDUCTIONS (\$000s)^(a)

Party	2020 Rec.	2021	2022	2023	2024	2025	2026
PG&E	\$13,566	\$15,364	\$16,172	\$14,400	\$14,711	\$15,500	\$16,081
Cal Advocates				\$0			
(a) PG&E-16-E, p. 10-31, Table 10-7, line 3 (2020-2022 2020-2023 recorded and forecast amounts); PG&E-3-ES, p. v (2023-2026 forecasts); PG&E-16-E, p. 10-5, Table 10-3, line 1 (Cal Advocates’ recommendation).							

Cal Advocates’ forecast exceeds PG&E’s revised forecast of \$14.4 million due to a post-February 28, 2022 forecast reduction by PG&E of \$7.3 million.¹²⁶³ PG&E’s forecast reduction is due to correction of an error in the use of historical MAT code splits used to determine the leak repair forecast that results in a 2023 unit forecast of 978 rather than the 1,476 in PG&E’s February 28, 2022 forecast.¹²⁶⁴ PG&E recommends that the Commission adopt PG&E’s adjusted forecast of \$14.4 million which is lower than Cal Advocates’ forecast. In addition, Cal Advocates’ forecast should be rejected since it is based on a flawed methodology as discussed below.

¹²⁶¹ PG&E-16-E, p. 10-17, lines 6-11.

¹²⁶² PG&E-03, p. 10-33, lines 2-26.

¹²⁶³ PG&E-16-E, p. 10-5, Table 10-3 line 1 and p. 10-6, Table 10-4, line . See PG&E-16-E, p. 10-31, Table 10-7, line 3 for PG&E’s adjusted forecast for 2021 through 2026.

¹²⁶⁴ PG&E-16-E, p. 10-18, lines 6-8.

In deriving its forecast, PG&E relied on the same 2.04 percent leak rate analysis discussed in Section 3.9.1.1 of this brief. PG&E applied a 15% historical above ground to below ground conversion rate to the total 2023 forecast leak volume of 27,739¹²⁶⁵ to account for leaks that are initially identified as an above ground leak but repaired as a below ground leak due to the work involved.¹²⁶⁶ PG&E then adjusted the leak volume by MAT using a historical MAT split based on 2018-2020 YTD June recorded data.¹²⁶⁷

Cal Advocates' lower 0.84 percent leak find rate uses a flawed methodology as addressed in Section 3.9.1.1 of this brief. Cal Advocates then applies that find rate to PG&E's proposed number of leak surveys, to yield a total number of 11,490 leak finds for 2023.¹²⁶⁸ Using PG&E's 2021 recorded leaks found and repaired for 2021,¹²⁶⁹ Cal Advocates calculates a 9 percent rate of repair and applies that rate to its forecasted leak finds of 11,490 to get a 2023 unit forecast total of 1,040.¹²⁷⁰

Cal Advocates' assumptions and approach are flawed for the same reasons discussed in Section 3.9.1.1 of this brief.¹²⁷¹ Its recommendation: is based on a single year of data and does not align with the three year compliance leak survey cycle; only accounts for one third of PG&E's gas distribution system; and does not include a volume of leaks found due to Call-ins from customer odor complaints, which is included in PG&E's 2023 forecast.¹²⁷²

¹²⁶⁵ PG&E-03, WP 10-33, line 1-10.

¹²⁶⁶ PG&E-03, WP 10-45, line 23.

¹²⁶⁷ PG&E-03, WP 10-33, line 24-34.

¹²⁶⁸ CALPA-02, p. 96, lines 8-10.

¹²⁶⁹ PG&E-16-E, p. 10-18, line 23 to p. 10-19, line 2.

¹²⁷⁰ CALPA-02, p. 97, Table 2-81.

¹²⁷¹ See also PG&E-16-E, p. 10-19, lines 4-10.

¹²⁷² PG&E-03, WP 10-44, Table 10-36.

3.9.4 Transmission Leak Repair (MAT JOP)

Transmission leak repair is the work to repair leaks on gas transmission facilities.

PG&E's transmission leak repair complies with the work required by GO 112-F and Leak Abatement Best Practice 21.¹²⁷³ Cal Advocates and TURN address this program and propose:

TABLE 3-56
TRANSMISSION LEAK REPAIR (MAT JOP): PG&E'S EXPENSE FORECAST AND PARTIES
RECOMMENDED REDUCTIONS (\$000s)^(a)

Party	2020 Rec.	2021	2022	2023
PG&E	\$5,828	\$8,513	\$10,168	\$13,210
Cal Advocates				\$(7,176)
TURN				\$(1,248)
(a) PG&E-16-E, p. 10-31, Table 10-6, line 2 (2020-2022) 2020-2023 recorded and forecast amounts; PG&E-3-ES, p. iii (2023 forecast); PG&E-16-E, p. 10-4, Table 10-2, line 2 (Cal Advocates' recommendation); PG&E-64, p. JCE 2-118 (TURN's recommendation).				

Cal Advocates agrees with PG&E's forecast for number of units for Grade 1 and Grade 2 above ground and below ground leaks. However, Cal Advocates disagrees with PG&E's above ground Grade 3 leak unit forecast.¹²⁷⁴ TURN recommends adopting a five-year average (2016-2020) unit cost instead of PG&E's proposed two-year average (2019-2020) unit cost.¹²⁷⁵

3.9.4.1 PG&E's Forecast of Grade 3 Transmission Leak Repairs Is Reasonable

As stated above, no party disputes PG&E's Grade 1 and Grade 2 leak repair forecast for this program. However, Cal Advocates questions PG&E's above ground Grade 3 leak forecast. PG&E's forecast is based on active open Grade 3 above ground leaks found in 2018-2020 that are coming due for repair in 2021-2023 to align with Best Practice 21.¹²⁷⁶ The 2023 forecast includes the known active open Grade 3 above ground leaks from 2020 multiplied by two to

¹²⁷³ PG&E-03, p. 10-43, line 7 to p. 10-44, line 8.

¹²⁷⁴ CALPA-02, p. 92, lines 9-14.

¹²⁷⁵ TURN-05, p. 13.

¹²⁷⁶ Under Best Practice 21 adopted in the Leak Abatement OIR, all leaks must be repaired within three years of discovery, except for leaks that are costly to repair relative to their size. D.17-06-015, p. 159, OP 5 and p. 153, COL 23.

account for the second half of the year. At the time PG&E developed its GRC forecast, only data for 2020 YTD June was available.¹²⁷⁷

Cal Advocates “recommends one third of the pending leaks, 159 units, for 2023... .”¹²⁷⁸ This is calculated by using the 2020 YTD June open above ground Grade 3 leaks of 476 divided by 3. Cal Advocates’ assumptions and approach are flawed. First, PG&E is not delaying any 2019 open above ground Grade 3 leaks into the test year as Cal Advocates asserts.¹²⁷⁹ As shown in PG&E’s workpapers, the 2023 above ground Grade 3 forecast is based on active above ground Grade 3 leaks from 2020 and not 2019.¹²⁸⁰ Pursuant to Best Practice 21, these leaks must be repaired within three years of discovery, i.e., in 2023 for a leak found in 2020.

In addition, by using the 2020 YTD June above ground Grade 3 leak count, Cal Advocate’s calculation does not take into consideration leaks found in the second half of 2020 that will require repair by 2023. Cal Advocates therefore significantly understates the above Ground Grade 3 leak count for 2020.¹²⁸¹

3.9.4.2 PG&E’s Proposed Unit Cost is Reasonable

PG&E’s 2023 forecasted unit cost is based on a 2-year average, 2019-2020, plus a 3.75 percent escalation rate due to increase in IBEW annual wages.¹²⁸² The 2-year average aligns with the operational change that took place in 2019 where the leak survey work transitioned from Gas Pipeline Operations Maintenance (GPOM) to the Leak Survey team.

¹²⁷⁷ PG&E-16-E, p. 10-20, lines 25-30.

¹²⁷⁸ CALPA-02, p. 92, lines 12-14.

¹²⁷⁹ CALPA-02, p. 92, lines 9-10.

¹²⁸⁰ PG&E-03, WP 10-66, line 41, fn. F.

¹²⁸¹ PG&E-16-E, p. 10-21, lines 6-17.

¹²⁸² PG&E-03, WP 10-67, line 12.

Previously, GPOM leak repairs were captured as part of routine maintenance as correctives under MWC JP.¹²⁸³

TURN bases its unit cost recommendation on a five-year historical average, 2016-2020, taking the recorded total costs by the total units for 2016-2020 and escalating using PG&E's 3.75 percent escalation rate.¹²⁸⁴ TURN's approach is flawed because the Best Practice 21 requirement that above ground Grade 3 be repaired within 36 months was not in effect until 2017 and thus the costs in 2016 and part of 2017 were less. In addition, prior to 2019, GPOM performed leak survey at facilities as part of routine maintenance, and leak repairs were captured as correctives under MWC JP rather than gradable leaks under MAT JOP. In 2019, this work was transitioned to the leak survey department resulting in higher leak find rates.¹²⁸⁵ For these reasons data from the years 2016-2018 used as part of TURN's unit forecast do not reflect the work currently being performed in MAT JOP.¹²⁸⁶

3.9.5 New Environmental Regulations Balancing Account (NERBA)

The continuation of the NERBA is addressed in Section 3.14.3.3 of this opening brief.

3.10 Gas System Operations

Exhibit PG&E-03, Chapter 11 presents PG&E's capital and expense forecasts for Gas System Operations (GSO). PG&E's GSO function is responsible for maintaining sufficient design day capacity on the system, and for planning and operating the GD and GT&S system. The GSO forecast also includes engineering for local GD facilities and activities related to the manual operation of gas facilities in the field. The chapter also describes the design of PG&E's

¹²⁸³ PG&E-03, p. 10-44, lines 2-5.

¹²⁸⁴ PG&E-16-E, p. 10-22, lines 21-23.

¹²⁸⁵ PG&E-03, p. 10-44, lines 2-7.

¹²⁸⁶ PG&E-16-E, p. 10-22, line 25 to p. 10-23, line 7.

GT&S system, including the capabilities of the backbone and storage facilities used to calculate costs and rates in other chapters.¹²⁸⁷

PG&E's Corrected Forecast for GD expense is \$21.842 million.¹²⁸⁸ PG&E's JCE forecast is \$22.302 million.¹²⁸⁹

PG&E's Corrected Forecast for GT&S expense is \$56.091 million.¹²⁹⁰ PG&E's JCE forecast is \$58.010 million.¹²⁹¹

PG&E's Corrected Forecast for GD capital expenditures is \$65.979 million in 2021, \$63.086 million in 2022, \$63.977 million in 2023, \$65.577 million in 2024, \$66.100 million in 2025, and \$46.704 million in 2026.¹²⁹² PG&E's JCE forecast for capital expenditures is \$69.351 million in 2021, \$69.805 million in 2022, \$71.661 million in 2023, \$71.524 million in 2024, \$70.413 million in 2025, and \$48.554 million in 2026.¹²⁹³

PG&E's Corrected Forecast for GT&S capital expenditures is \$28.280 million in 2021, \$13.887 million in 2022, \$13.141 million in 2023, \$13.469 million in 2024, \$13.841 million in 2025, and \$14.263 million in 2026.¹²⁹⁴ PG&E's JCE forecast for capital expenditures is

¹²⁸⁷ PG&E-03, p. 11-1, lines 6-16.

¹²⁸⁸ PG&E-16-E, p. 11-4, Table 11-1, line 7.

¹²⁸⁹ PG&E-64, p. 3-1, Table 3A-1, lines 34-36.

¹²⁹⁰ PG&E-3-ES, p. iii, which reflects PG&E's rebuttal forecast updated with corrected escalation factors.

¹²⁹¹ PG&E-64, p. 3-1, Table 3A-1, lines 31-33 and 37.

¹²⁹² PG&E-16-E, p. 11-44, Table 11-9, line 14 (2021 and 2022) and PG&E-3-ES, p. v, which reflects PG&E's rebuttal forecast updated with corrected escalation factors. (2023-2026).

¹²⁹³ PG&E-64, p. 3-6, Table 3B-1, lines 20-21 (2023); p. 3-10, Table 3B-2, lines 20-21 (2022); and p. 3-14, Table 3B-3, lines 20-21 (2021). Forecasts for 2024-2026 are not included in the JCE but are provided here for reference.

¹²⁹⁴ PG&E-16-E, p. 11-45, Table 11-10, line 5 (2021 and 2022) and PG&E-3-ES, p. v, which reflects PG&E's rebuttal forecast updated with corrected escalation factors. (2023-2026).

\$34.909 million in 2021, \$19.192 million in 2022, \$16.814 million in 2023, \$15.317 million in 2024, \$14.932 million in 2025, and \$14.961 million in 2026¹²⁹⁵

Of the 11 expense MATs related to Gas System Operations, only 4 are disputed. Similarly, for the 10 capital MATs, only 3 are disputed. The undisputed programs, associated MATs, and corresponding expense and capital forecasts are identified in Appendix A. In the remainder of this Section 3.10, we address the disputed programs.

**TABLE 3-57
SUMMARY OF ISSUES ADDRESSED IN SECTION 3.10**

Section	Disputed Program	Impacted MATs
3.10.1	Gas Distribution Control Center (GDCC) Operations	Expense (MAT FGA)
3.10.2	Gas Distribution Manual Field Operations – Expense	Expense (MAT FGB)
3.10.3	GT&S Operations	Expense (MAT CMA)
3.10.4	Electric Power for Compressor Fuel and Other Electric Equipment	Expense (MAT CMB)
3.10.5	Gas Distribution SCADA Visibility Program – Remote Terminal Units	Capital (MAT 4AM)
3.10.6	Gas Transmission SCADA Visibility Program	Capital (MAT 76M)
3.10.7	Gas Transmission Capacity for Load Growth	Capital (MAT 73A)

3.10.1 Gas Distribution Control Center (GDCC) Operations (MAT FGA)

The GDCC enables GSO to mitigate operational gas distribution system risk by integrating operations, capacity planning, integrity management, maintenance, and repairs into a highly coordinated effort that is monitored and supervised from a single location. It enables system operators, who staff the GDCC 24 hours a day, 7 days a week, to remotely monitor the gas distribution system, including key equipment, and to respond quickly to mitigate events that could occur despite PG&E’s preventative efforts.¹²⁹⁶ Activities under GDCC Operations also include control room management compliance, technology maintenance (including SCADA and

¹²⁹⁵ PG&E-64, p. 3-6, Table 3B-1, lines 22-23 (2023); p. 3-10, Table 3B-2, lines 22-23 (2022); and p. 3-14, Table 3B-3, lines 22-23 (2021). Forecasts for 2024-2026 are not included in the JCE but are provided here for reference.

¹²⁹⁶ PG&E-03, p. 11-38, lines 8-15.

control console interfaces), and operations engineering.¹²⁹⁷ Cal Advocates is the only party that addresses this program and proposes:

TABLE 3-58
GAS DISTRIBUTION CONTROL CENTER OPERATIONS (MAT FGA): PG&E’S EXPENSE
FORECAST AND PARTIES RECOMMENDED REDUCTIONS (\$000s)^(a)

Party	2020 Rec.	2021	2022	2023
PG&E	\$7,650	\$8,175	\$8,519	\$8,838
Cal Advocates				\$(839)
(a) PG&E-16-E, p. 11-43, Table 11-7, line 3 (2020-2023 recorded and forecast costs); PG&E-16-E, p. 11-4, Table 11-1, line 2 (Cal Advocates’ recommendation).				

Cal Advocates’ proposed reduction is based on the disallowance of PG&E’s forecast expenditures for the Gas Control Room Consolidation plan and disallowance of PG&E’s forecast for the SCADA Predictive Health Analytics project.¹²⁹⁸

3.10.1.1 Cal Advocates’ Proposed Reduction Includes Erroneous Costs

Cal Advocates recommends a total \$0.839 million reduction to PG&E’s forecast. Of Cal Advocates proposed \$0.839 million reduction, \$0.56 million is specific to Cal Advocates’ opposition to PG&E’s Gas Control Consolidation forecast.¹²⁹⁹ However, this \$0.56 million reduction represents the total of Gas Control Consolidation 2023 forecast costs for both the GDCC (MAT FGA) (\$77,707)¹³⁰⁰ and the Gas Transmission Control Center (MAT CMA) (\$481,849).¹³⁰¹ When the correct Gas Control Consolidation forecast for MAT FGA of \$77,707 is used, Cal Advocates’ proposed disallowance for MAT FGA becomes \$0.357 million, not \$0.838 million (i.e., \$0.838 million - \$0.481 million).

¹²⁹⁷ PG&E-16-E, p. 11-10, lines 16-25.

¹²⁹⁸ CALPA-03, p. 6, lines 9-10 and lines 21-22; PG&E-16-E, p. 11-10, line 27 to p. 11-11 line 2.

¹²⁹⁹ CALPA-03, p. 6, line 9-10.

¹³⁰⁰ PG&E-03, p. WP 11-8, Table 11-8, line 9.

¹³⁰¹ PG&E-03 p. WP 11-15, Table 11-15, line 10.

3.10.1.2 Costs Associated with PG&E's Consolidation Plan Are Recoverable

In its initial testimony, PG&E proposed a reorganization of its gas system control center (Consolidation Plan) to operate the gas system under a geographical structure (north-south) rather than the current functional structure (distribution-transmission) in order to capture certain efficiencies and benefits. The reorganization was subject to approval by members of the IBEW.¹³⁰² The Consolidation Plan included a forecast for the costs of cross-training system operators that would train and qualify employees to operate both the distribution and transmission system. Cross training system operators would have provided the following benefits: (1) a more effective emergency response posture; (2) a broader pool of employees that could staff shift assignments; (3) improved information handoffs and decision making between distribution and transmission operations; and (4) reducing the risk of external factors impacting PG&E's ability to safely staff the Gas Distribution Control Center and Gas Transmission Control Center due to COVID-19 medical isolations, exhaustion of staff eligible for overtime or back-to-back shifts, or other staffing challenges.¹³⁰³

The Consolidation Plan would have allowed PG&E to operate with approximately six fewer FTE employees in the control room than would otherwise be required to operate each system resulting in savings. PG&E stated in its testimony that it had left six vacant positions unfilled in preparation for implementation of the Consolidation Plan.¹³⁰⁴

After filing the 2023 GRC on June 30, 2021, members of the IBEW voted to not adopt PG&E's proposed Gas Control Room Consolidation.¹³⁰⁵ In order to maintain safe operation of the gas system, PG&E plans to backfill the approximately six additional gas control operators and supervisors that were left vacant in preparation for implementation of the Gas Control Room

¹³⁰² The reorganization is described in PG&E-16-E, p. 11-12, line 24 to p. 11-13, line 18.

¹³⁰³ PG&E-16-E, p. 11-13, lines 4-12.

¹³⁰⁴ PG&E-16-E, p. 11-3, lines 17-18.

¹³⁰⁵ PG&E-16-E, PG&E's response to Data Request CalAdvocates_252-Q003(e), dated 2/17/22, p. AppA-374.

Consolidation plan. PG&E forecasts that the cost of backfilling the six gas control operators and supervisor positions left vacant will exceed the incremental cost forecast for the Gas Control Room Consolidation plan described.¹³⁰⁶ As a result, Cal Advocates’ proposal to disallow Gas Control Room Consolidation costs should be rejected and PG&E’s forecast for Gas Control Consolidation costs should be approved, given PG&E’s demonstrated need to increase staffing levels back to pre-consolidation plan levels.¹³⁰⁷

3.10.1.3 The SCADA Predictive Health Analytics Work Is Reasonable

Cal Advocates claims PG&E has not shown that the Supervisory Control and Data Acquisition (SCADA)¹³⁰⁸ Predictive Health Analytics program is a new expense that requires additional funding.¹³⁰⁹ However, Cal Advocates misunderstands the nature of this work. This is not new or additional work, but merely a shift to MAT FGA of existing work previously charged to other MAT codes.

As shown in rebuttal testimony and explained in response to data request CalAdvocates_252-Q004,¹³¹⁰ the SCADA Predictive Health Analytics was forecast as part of the 2019 GT&S Rate Case¹³¹¹ and the 2020 GRC¹³¹² in MAT JVA and MAT 2FA as a technology project. In preparing the 2023 GRC forecast, PG&E presented the forecast for

¹³⁰⁶ PG&E-16-E, p.11-4, lines 9-11.

¹³⁰⁷ PG&E-16-E, p. 11-14, lines 11-15.

¹³⁰⁸ PG&E’s SCADA program provides pressure and flow data to the GDCC to provide 24/7 monitoring of the gas distribution system. SCADA devices are a central tool that provides GDCC operators visibility into the gas system. PG&E-16-E, p. 11-25, lines 8-12.

¹³⁰⁹ CALPA-03, p. 7, lines 4-6.

¹³¹⁰ PG&E-16-E, PG&E’s response to Data Request CalAdvocates_252-Q004, dated 2/17/22, pp. AppA-370 to AppA-371.

¹³¹¹ PG&E-16-E, Attachment B, p. 11-AtchB-1 to p. 11-AtchB-4 (Workpapers for MWCs JV and 2F from 2019 GT&S case (A.17-11-009), Exhibit (PG&E-13), WP 12-30 to WP 12-33).

¹³¹² PG&E-16-E, Attachment C, p. 11-AtchC-1 to p. 11-AtchC-3 (Workpapers for MATs JVA and 2FA from 2020 GRC (A.18-12-009), HE-14: Exhibit (PG&E-3), WP 11-28 to WP 11-30).

SCADA Predictive Health Analytics in MAT FGA (GDCC) and MAT CMA (GTCC) instead of forecasting the costs in MAT JVA or MAT 2FA. The forecast presented in the 2023 GRC is simply an accounting cost transfer for continuing activities and is not a new program to the GRC.¹³¹³ PG&E is not forecasting any incremental headcount additions to perform SCADA Predictive Health Analytics work in this GRC. Approximately 1.5 FTEs in GSO have redirected their time away from supporting IT project work recorded to MAT JVA and MAT 2FA to support SCADA Predictive Health Analytics activities. Though these FTEs will be charging to different MAT codes, they will be performing the same type of work as previously.¹³¹⁴ Accordingly, the Commission should reject Cal Advocates' \$0.28 million reduction to MAT FGA for SCADA predictive analytics work.

3.10.2 Gas Distribution Manual Field Operations – Expense (MAT FGB)

Gas Distribution Manual Field Operations must be performed from time to time to connect and calibrate pressure test gauges and portable pressure recorders, to retrieve and replace paper charts from the recorders, to remove incidental pipeline liquids, and to perform similar activities. Furthermore, when system demands are high, and to deal with other abnormal situations, personnel may be dispatched to operate certain field equipment manually.¹³¹⁵ Cal Advocates is the only party that addresses this program and proposes:

TABLE 3-59
GAS DISTRIBUTION MANUAL FIELD OPERATIONS (MAT FGB): PG&E'S EXPENSE
FORECAST AND PARTIES RECOMMENDED REDUCTIONS (\$000s)^(a)

Party	2020 Rec.	2021	2022	2023
PG&E	\$957	\$911	\$1,020	\$1,056
Cal Advocates				\$(226)
(a) PG&E-16-E, p. 11-43, Table 11-7, line 4 (2020-2023 recorded and forecast costs); PG&E-16-E, p. 11-4, Table 11-1, line 3 (Cal Advocates' recommendation).				

¹³¹³ PG&E-16-E, p. 11-15, lines 8-15.

¹³¹⁴ PG&E-16-E, p. 11-15, lines 18-23.

¹³¹⁵ PG&E-16-E, p. 11-15, line 26 to p. 11-16, line 3.

PG&E based the 2023 forecast on 2020 recorded expenses, plus escalation. Cal Advocates' proposed reduction is based on utilizing 2021 recorded expenditures as the basis for the 2023 forecast. Cal Advocates asserts that its proposed reduction is warranted because "PG&E's expenses decreased by over 10% per year on average for each year over the historical period 2016 and 2021."¹³¹⁶

PG&E acknowledges that there has been a decreasing trend in expenditures during that timeframe due to a decrease in the number of manual field operations that were required to calibrate portable pressure chart recorders in the field.¹³¹⁷ In fact, PG&E's 2023 forecast of \$1.056 million is lower than the un-escalated six-year average (2016-2021) of costs of \$1,113,777, thus reflecting a decline in cost.¹³¹⁸ However, the frequency at which PG&E performs manual field operations is variable and is dependent upon system conditions that include the need to throttle valves during peak demand days, to performing site visits after winter storms to ensure asset calibration.¹³¹⁹ Cal Advocates' reduction is too steep, and does not address the potential variability of these operations. PG&E also objects to Cal Advocates' use of 2021 recorded costs as the basis for the 2023 MAT FGB forecast as 2021 recorded expenditures were not available to PG&E at the time of filing. The use of 2021 recorded data in this GRC is further discussed in Section 1.5 of this opening brief.

3.10.3 GT&S Operations (MAT CMA)

PG&E requires staff in the Gas Transmission Control Center (GTCC), Gas Scheduling & Accounting, Gas System Planning (GSP) and Gas Operations Control Technology & Integration team to operate the GT&S system, maintain our SCADA and other GTCC systems, support customers using the system, and plan for capacity and operations on a daily and longer-term

¹³¹⁶ CALPA-03, p. 8, lines 9-10.

¹³¹⁷ PG&E-16-E, p. 11-16, lines 26-30.

¹³¹⁸ PG&E-16-E, p. 11-17, lines 7-14.

¹³¹⁹ PG&E-16-E, p. 11-16, line 30 to p. 11-17, line 3.

basis. These organizations are forecast under MAT CMA.¹³²⁰ The 2023 forecast for MAT CMA is \$17.3 million.¹³²¹ Cal Advocates is the only party that addresses this program and proposes:

TABLE 3-60
GT&S OPERATIONS (MAT CMA): PG&E’S EXPENSE FORECAST AND PARTIES
RECOMMENDED REDUCTIONS (\$000s)^(a)

Party	2020 Rec.	2021	2022	2023
PG&E	\$13,745	\$15,805	\$16,650	\$17,297
Cal Advocates				\$(1,932)
(a) PG&E-16-E, p. 11-44, Table 11-8, line 2 (2020-2022 recorded and forecast costs); PG&E-3-ES, p. iii (2023 forecast); PG&E-16-E, p. 11-5, Table 11-2, line 2 (Cal Advocates’ recommendation).				

Cal Advocates’ proposed reduction is based on the disallowance of PG&E’s forecast expenditures for the Gas Control Room Consolidation plan and the SCADA Predictive Health Analytics project, and the disallowance of PG&E’s request for expenditures related to the hiring of five incremental gas transmission system planning employees.¹³²²

3.10.3.1 The Gas Control Room Consolidation Forecast is Reasonable

As discussed in Section 3.10.1.1 above, in relation to the GDCC (MAT FGA), the IBEW voted to not adopt PG&E’s proposed Gas Control Room Consolidation plan to operate the system under a geographical structure (north-south) rather than the current functional structure (distribution-transmission). Accordingly, PG&E plans to backfill approximately six additional gas control operators and supervisors that were left vacant in preparation for implementation of the Gas Control Room Consolidation plan. The cost of backfilling the six gas control operators and supervisor positions left vacant will exceed the incremental cost forecast for the Gas Control Room Consolidation plan described.¹³²³

1320 PG&E-03, p. 11-12, line 10 to p. 11-14, line 5.

1321 PG&E-3-ES, p. iii.

1322 CALPA-3, pp. 6-10, summarized at PG&E-16-E, p. 11-18, lines 7-27.

1323 PG&E-03, WP 11-21.

As a result, Cal Advocates’ proposal to disallow Gas Control Room Consolidation costs should be rejected and PG&E’s forecast for Gas Control Consolidation costs should be approved, given PG&E’s demonstrated need to increase staffing levels back to pre-consolidation plan levels.¹³²⁴

3.10.3.2 SCADA Predictive Health Analytics

As discussed in Section 3.10.1.1 above in relation to the GDCC (MAT FGA), the SCADA Predictive Health Analytics program is not new or additional work. The SCADA Predictive Health Analytics work was forecast in previous rate cases in MAT JVA and MAT 2FA as a technology project.¹³²⁵ The forecast presented in the 2023 GRC is simply an accounting cost transfer for continuing activities and is not a new program to the GRC.¹³²⁶ Approximately 1.5 FTEs in GSO have redirected their time away from supporting IT project work recorded to MAT JVA and MAT 2FA to support SCADA Predictive Health Analytics activities and will be performing the same type of work as previously.¹³²⁷

3.10.3.3 Hiring Additional Gas Transmission System Planning Employees is Reasonable

PG&E has demonstrated the need to hire five additional gas transmission system planning employees. In PG&E’s response to data requests,¹³²⁸ PG&E explained the need for the five additional local transmission engineers citing a significant volume increase in gas system planning work associated with integrity management, integrated investment planning, and

¹³²⁴ PG&E-16-E, p. 11-14, lines 4-15.

¹³²⁵ PG&E-16-E, Attachment B, p. 11-AtchB-1 to p. 11-AtchB-4 (Workpapers for MWCs JV and 2F from 2019 GT&S case (A.17-11-009), Exhibit (PG&E-13), WP 12-30 to WP 12-33).

¹³²⁶ PG&E-16-E, p. 11-15, lines 8-15.

¹³²⁷ PG&E-16-E, p. 11-15, lines 18-23.

¹³²⁸ PG&E-16-E, PG&E’s response to Data Request CalAdvocates_057-Q012, dated 9/21/21, p. AppA-380; PG&E-16-E, PG&E’s response to Data Request CalAdvocates_252-Q002, dated 2/17/22 and attachment CalAdvocates_252-Q002Atch01, pp. AppA-367 to AppA-369.

emergency support.¹³²⁹ Prior to the hiring of the five GSP engineers in May 2021, PG&E was unable to meet the observed volume of gas system planning requirements without additional support. This resulted in several transmission projects where GSP support was requested and unfulfilled.¹³³⁰

PG&E's GSP team performed a workload study vs. resources between the demands seen between 2016 and 2020 and forecast future need between 2021 and 2026.¹³³¹ The study showed that PG&E's GSP team was projected to be understaffed by 17 percent by 2021. As a result, PG&E pursued the hiring of five additional employees to close the forecast resource gap.¹³³²

3.10.4 Electric Power for Compressor Fuel and Other Electric Equipment (MAT CMB)

Most large compressors that move gas through PG&E's backbone transmission lines and into storage are fueled by gas taken from the pipeline delivered to the system by shippers as an in-kind incremental percentage addition to their normal deliveries. Under this arrangement, compressor fuel costs are born by shippers. However, PG&E also operates electric-powered gas compressors at Bethany and Delevan compressor stations on the backbone transmission system, at the McDonald Island storage facility, and on the local transmission system in Santa Rosa. Since customers cannot provide in-kind fuel for electric compressors, PG&E must obtain electricity to power them. To maintain the shipper-pays construct, PG&E includes the costs of electricity for electric-powered gas compressors in rates. MAT CMB also includes the costs for

¹³²⁹ PG&E-16-E, p. 11-20, lines 24-29.

¹³³⁰ PG&E-16-E, p. 11-21, lines 3-6.

¹³³¹ CALPA-37, PG&E's Response to Cal Advocates 283-Q001, dated 8/15/22, and Attachment 283-Q001Atch01.

¹³³² PG&E-16-E, p.11-21, lines 8-12 and 15-18.

electric power used by SCADA devices, station buildings, and other electric equipment on the transmission system.¹³³³

PG&E recorded \$27.0 million to MAT CMB in 2020, and is forecasting to spend \$29.1 million in 2023, a \$2.1 million increase.¹³³⁴ The forecast increase is driven by increased electricity usage and higher electricity costs to run the electric gas compressor stations, and by forecast escalation.¹³³⁵ Cal Advocates is the only party that addresses this program and proposes:

TABLE 3-61
ELECTRIC POWER FOR COMPRESSOR FUEL AND OTHER ELECTRIC EQUIPMENT
(MAT CMB): PG&E’S EXPENSE FORECAST AND PARTIES RECOMMENDED
REDUCTIONS (\$000s)^(a)

Party	2020 Rec.	2021	2022	2023
PG&E	\$13,745	\$15,805	\$16,650	\$29,125
Cal Advocates				\$(1,996)
(a) PG&E-16-E, p. 11-44, Table 11-8, line 3 (2020-2022 recorded and forecast costs); PG&E-3-ES, p. iii (2023 forecast); PG&E-16-E, p. 11-5, Table 11-2, line 3 (Cal Advocates’ recommendation).				

Cal Advocates’ proposed forecast is between the historic average for years 2016 through 2020 and PG&E’s forecast. Cal Advocates’ claims that its forecast “reflects the historical spending levels recorded from 2016 to 2020.”¹³³⁶ However, this recommended forecast reduces PG&E’s forecast by \$1.6 million and is insufficient. PG&E’s proposal to use the base year 2020 recorded spend escalated and adjusted for higher forecast usage and electricity prices is a sound forecasting approach.¹³³⁷ Cal Advocates’ historical 2016-2020 average cost comparison does not cover these expected increases adequately.

¹³³³ PG&E-03, p. 11-43, line 27 to p. 11-44, line 13.

¹³³⁴ PG&E-3-ES, p. iii.

¹³³⁵ PG&E-03, p. 11-47 lines 24-28.

¹³³⁶ CALPA-03, p.11, lines 10-14.

¹³³⁷ PG&E-03, p. 11-47, lines 13-28.

Cal Advocates' testimony also makes reference to a PG&E recorded amount of \$1.5 million to MAT CMB in 2021.¹³³⁸ However, this was an error that was corrected in PG&E's email to Cal Advocates on May 16, 2022 to clarify that PG&E recorded \$24.3 million in 2021.¹³³⁹ Any reliance by Cal Advocates on the \$1.5 million amount to support Cal Advocates' recommendation to reduce PG&E's forecast¹³⁴⁰ is therefore misplaced.

3.10.5 Gas Distribution SCADA Visibility Program – Remote Terminal Units – Capital (MAT 4AM)

PG&E's SCADA program sends pressure and flow data to the GDCC to provide 24/7 monitoring of the gas distribution system. SCADA devices are a central tool that provides GDCC operators visibility into the gas system. If the devices detect conditions that are out of the normal range, they send an alarm to the GDCC that is investigated and remediated. Data from SCADA devices also help GSP engineers validate and calibrate hydraulic models leading to more efficient designs and support predictive health analytics.¹³⁴¹

There are two basic types of SCADA devices: remote terminal units (RTUs) and electric recorder transmitters (ERXs). RTUs are capable of real time data transmission with multiple sensing capabilities, including pressure transmitters, pressure differential transmitters, switches, and other instruments. RTU units are therefore the most valuable in detecting abnormal conditions in real time and allowing the GDCC to mitigate unsafe situations. ERX devices are capable of periodic data transmission at fixed intervals with limited sensing capabilities. RTU

¹³³⁸ PG&E-16-E, p. 11-24, lines 7-10.

¹³³⁹ On March 9, 2022, PG&E provided to all parties 2021 recorded expenditures that incorrectly showed MAT CMB had 2021 recorded expenditures of \$1.5 million. PG&E inadvertently excluded the electricity costs for gas compressor stations and only showed the electricity costs for electrically powered field equipment. PG&E provided the corrected 2021 recorded expenses for MAT CMB of \$24,278,267 in an email to Cal Advocates dated May 16, 2022. PG&E-16-E, p. 11-24, lines 11-17 and p. 11-24, line 29 to p. 11-25 line 3.

¹³⁴⁰ CALPA-03, p. 11, lines 7-9.

¹³⁴¹ PG&E-16-E, p. 11-25, lines 8-18.

installations are forecast in MAT 4AM.¹³⁴² TURN is the only party that addresses this program and proposes:

TABLE 3-62
GAS DISTRIBUTION SCADA VISIBILITY PROGRAM – REMOTE TERMINAL UNITS (MAT 4AM): PG&E’S CAPITAL FORECAST AND PARTIES RECOMMENDED REDUCTIONS
(\$000s)^(a)

Party	2020 Rec.	2021	2022	2023	2024	2025	2026
PG&E	\$26,018	\$26,028	\$28,213	\$22,787	\$23,357	\$22,909	\$2,520
TURN ^(b)				\$(22,787)	\$(23,357)	\$(22,909)	\$(2,520)

(a) PG&E-16-E, p. 11-45, Table 11-9, line 13 (2020-2022 recorded and forecast costs); PG&E-3-ES, p. v (2023-2026 forecasts); PG&E-64, p. JCE 3-124 (TURN’s recommendation).
(b) TURN recommends no funding for this program. The recommended forecast reductions have been adjusted to match PG&E’s Corrected Forecast resulting in a forecast recommendation of \$0.

TURN proposes to cancel the GD SCADA visibility program completely and provide no further funding.¹³⁴³ TURN claims that the RSE for this program shows that the value of the risk reduction from PG&E’s proposed work would be minimal compared to the program’s costs.¹³⁴⁴ TURN provides no other basis for cancelling the program.

3.10.5.1 The SCADA Visibility Program Is Reasonable and Prudent

PG&E provided extensive testimony discussing the operational and regulatory drivers justifying this program.¹³⁴⁵ No party, including TURN, addressed this testimony. Visibility by operators into the conditions of the system is central to the safety of PG&E’s operations and is consistent with state and federal regulation to identify and mitigate the risk of abnormal operating conditions. SCADA is the chief tool used by the GDCC to ensure safe distribution system operations.¹³⁴⁶

¹³⁴² PG&E-16-E, p. 11-25, lines 21-30.

¹³⁴³ TURN-02, p. 139, lines 1-2.

¹³⁴⁴ TURN-02, p. 124, lines 5-7.

¹³⁴⁵ PG&E-03, p. 11-31, line 10 to p. 11-34, line 7; PG&E-16-E, p. 11-26, line 17 to p. 11-28, line 17.

¹³⁴⁶ PG&E-16-E, p. 11-27, lines 14-18.

PG&E’s strategy is to provide 100 percent visibility into all hydraulically independent systems (HIS) containing 50 or more customers by 2025 to provide the GDCC with increased visibility into system performance that allows quicker identification and response to abnormal operating conditions. PG&E is forecasting to install RTUs at the remaining 297 locations identified (97 in 2023, 97 in 2024, 93 in 2025, and 10 in 2026) to complete the SCADA installation program.¹³⁴⁷

PG&E’s GDCC SCADA program also supports and enhances compliance with state and federal regulations set forth in 49 CFR, § 192.741,¹³⁴⁸ GO No. 58-A,¹³⁴⁹ and PUC §961¹³⁵⁰ requiring the installation of monitoring systems on PG&E’s gas pipeline system to provide indications of abnormal conditions to address unsatisfactory operating conditions and to minimize hazards and systemic risks to the gas system, including accidents, explosions, fires, and dangerous conditions. The GDCC’s role is to be able to discern the operational performance of each HIS. This requires PG&E to have visibility of all the inputs into the HIS, whether they are classified as high, medium, or low risk.¹³⁵¹

¹³⁴⁷ PG&E-03, WP 11-53. PG&E is forecasting that the program will carryover 10 RTU installations into 2026 due to long lead permit requirements and active land acquisition proceedings.

¹³⁴⁸ 49 CFR § 192.741(a)(c) (“Each distribution system supplied by more than one district pressure regulating station must be equipped with telemetering or recording pressure gauges to indicate the gas pressure in the district . . . If there are indications of abnormally high or low pressure, the regulator and the auxiliary equipment must be inspected and the necessary measures employed to correct any unsatisfactory operating conditions.”)

¹³⁴⁹ General Order 58-A (Rev. Nov. 10, 2016), pp. 6-7, § 9, “(a) Each gas utility shall own and maintain at least one recording pressure device on each principal distribution main leaving each major control facility such as a compressor station, holder station, or terminal . . . (b) Each gas utility shall own and maintain at least one low pressure, portable pressure recording device for each one hundred (100) miles or fraction thereof of low pressure main in any separate distribution system.”

¹³⁵⁰ Pub. Util. Code § 961(d)(5), Gas Utilities shall “[p]rovide for appropriate and effective system controls, with respect to both equipment and personnel procedures, to limit the damage from accidents, explosions, fires, and dangerous conditions.”

¹³⁵¹ PG&E-16-E, p. 11-27 line 19 to p. 11-28 line 9.

Completing PG&E's GD SCADA network provides the GDCC the ability to implement a predictive approach to operating the system. The GD SCADA program is the most effective method to safely and reliably monitor the GD system, allowing GDCC personnel to investigate potential abnormal conditions before they escalate into emergencies and to dispatch field personnel in an efficient and effective manner rather than relying on notifications from the public or emergency response personnel before actions can be initiated.¹³⁵²

3.10.5.2 The Remaining Proposed SCADA Installations Are Necessary

TURN's claim that the GD SCADA Visibility program is addressing relatively lower risk assets compared to those it targeted in the early years of the program¹³⁵³ is simply incorrect. PG&E has prioritized installing at least minimal visibility in all HIS systems of 50 or more customers. But to fully understand what is occurring in these systems, PG&E needs visibility of all the input gas sources to each HIS. This is what is being completed in the final years of the GD SCADA Visibility program.¹³⁵⁴

PG&E is forecasting a total of 68 "high" priority and 199 "medium" priority SCADA installations on the GD system out of the 297 planned RTU locations. Only a fraction (approximately 10 percent, or 30 locations) of the remaining forecast SCADA installations on the GD system are classified as "low risk."¹³⁵⁵ However, risk scoring is just one method to identify and prioritize locations on the GD system where SCADA should be installed. As discussed previously, the goal of PG&E's SCADA program is to provide 100 percent visibility

¹³⁵² PG&E-16-E, p. 11-28, lines 10-17.

¹³⁵³ TURN-02, p. 123, line 13 to p. 124, line 1.

¹³⁵⁴ PG&E-16-E, p. 11-28, line 23 to p. 11-29, line 2.

¹³⁵⁵ PG&E-16-E, p. 11-30, lines 1-8; PG&E-16-E, PG&E's response to Data Request TURN_208-Q001, dated 5/24/22, p. AppA-381.

into the GD system. This goal cannot be accomplished without continuing the installation of SCADA at the remaining 297 locations forecast in this GRC.¹³⁵⁶

3.10.5.3 RSE Scores Should Not Be The Sole Criteria For this Program

TURN did not address any of PG&E's testimony discussing the operational justification for this program. Instead, TURN cites the relatively low RSE score for this program as the sole reason for cancelling the program.¹³⁵⁷ TURN's reliance on its flawed RSE analysis is addressed in Sections 2.3 and 3.2.2 of this opening brief.¹³⁵⁸

Furthermore, the opinions of TURN's witness Lesser should be accorded lower weight than the judgment of PG&E's expert witness Dan Menegus, the PG&E Gas Operations Senior Director responsible for Gas System Operations. TURN witness Lesser lacks the operational experience and expertise necessary to make judgments about the GD SCADA Visibility program. Dr. Lesser has not worked as an employee of a natural gas transmission or distribution utility; is not an expert on PHMSA regulations; and has no experience working on any committee of the AGA.¹³⁵⁹ In contrast, Mr. Menegus was the Senior Director of GSO whose responsibilities include: Gas Control and Gas Emergency Response, Gas System Hydraulic Planning, Gas Transmission Project Engineering and oversight of various engineering and support organizations, computerized systems, and technologies that enable the GSO function to be performed. Mr. Menegus holds a Master of Science degree in Mechanical Engineering and has 36 years of experience in engineering design of gas pipeline and station facilities; project management; system operations; operations and maintenance engineering; strategic planning; quality assurance; and developing new gas technologies. He has served as chair of the AGA

¹³⁵⁶ PG&E-16-E, p. 11-30, lines 11-15.

¹³⁵⁷ TURN-02, p. 124, lines 5-7.

¹³⁵⁸ PG&E-16-E, p. 11-31, lines 13-17.

¹³⁵⁹ PG&E-16-E, p. 11-30, line, 22 to p. 11-31, line 10.

Task Group on Automated Valves and served on the Interstate Natural Gas Association of America Task Force on Emergency Preparedness and Response.¹³⁶⁰

3.10.6 Gas Transmission SCADA Visibility Program – Capital (MAT 76M)

The goal of the GT SCADA Visibility program is to install SCADA at all transmission regulating stations and compressor stations to enable a high degree of monitoring and control for the GTCC. The installations proposed under this program will improve the GTCC’s ability to detect and prevent potential operational issues before they escalate into events, and its ability to mitigate events that may occur despite these preventative efforts. In this GRC, PG&E’s forecast requests funding to install a total of 32 additional SCADA sites (eight per year) on Local Transmission (LT) stations between 2023-2026, bringing LT regulator station visibility from 60 percent at the end of 2022 to approximately 69 percent by 2026.¹³⁶¹ TURN is the only party that addresses this program and proposes:

TABLE 3-63
GAS TRANSMISSION SCADA VISIBILITY PROGRAM (MAT 76M): PG&E’S CAPITAL FORECAST AND PARTIES RECOMMENDED REDUCTIONS (\$000s)^(a)

Party	2020 Rec.	2021	2022	2023	2024	2025	2026
PG&E	\$1,917	\$2,672	\$2,704	\$2,778	\$2,848	\$2,927	\$3,018
TURN ^(b)				\$(2,778)	\$(2,848)	\$(2,927)	\$(3,018)
(a) PG&E-16-E, p. 11-46, Table 11-10, line 4 (2020-2022 recorded and forecast costs); PG&E-3-ES, p. v (2023-2026 forecasts); PG&E-64, p. JCE 3-128 (TURN’s recommendation). (b) TURN recommends no funding for this program. The recommended forecast reductions have been adjusted to match PG&E’s Corrected Forecast resulting in a forecast recommendation of \$0.							

TURN proposes to cancel the GT SCADA visibility program completely and provide no further funding. TURN claims that the RSE for this program “shows that the value of the risk

¹³⁶⁰ PG&E-13, p. DM-1, lines 8-23.

¹³⁶¹ PG&E-16-E, p. 11-33, lines 1-11.

reduction from PG&E's proposed work would be minimal compared to the program's costs."¹³⁶² TURN provides no other basis for cancelling the program.

3.10.6.1 The SCADA Visibility Program Is Reasonable and Prudent

PG&E provided extensive testimony discussing the operational and regulatory drivers justifying this program.¹³⁶³ No party, including TURN, addressed this testimony. PG&E's GT SCADA Visibility program is central to the safety of PG&E's operations and is consistent with state and federal regulation to identify and mitigate risk of abnormal operating conditions. SCADA visibility provides the GTCC the situational awareness to identify conditions that may lead to abnormal events, diagnostic capabilities to determine the cause (e.g., station failure, pipeline capacity constraints, etc.), and the ability to proactively take action to reduce the time to respond and minimize potential impact on customers if they should occur. In addition, PG&E's GT SCADA program provides the GTCC the ability to implement a predictive approach to operating the system.¹³⁶⁴ PG&E's GTCC SCADA programs also support and enhance compliance with state and federal regulations as described in Section 3.10.5.1 of this brief for the GD SCADA program.

PG&E's goal of the Transmission SCADA Visibility program is to install SCADA at all transmission regulating stations and compressor stations. Since 2018, PG&E has at least one SCADA device at each backbone station that along with PG&E's Online Pipeline Simulator provides 100 percent visibility to the backbone system. By the end of 2022, PG&E estimates it will have 60 percent visibility into the local transmission system. New SCADA points are identified on an ongoing basis as system dynamics change and new risks are identified. PG&E's gas system is not static. The GT SCADA Visibility program provides funding for those

¹³⁶² TURN-02, p. 127, lines 1-3.

¹³⁶³ PG&E-03, p. 11-57, line 23 to p. 11-60, line 15; PG&E-16-E, p. 11-31, line 18 to p. 11-35, line 30.

¹³⁶⁴ PG&E-16-E, p. 11-33, line 15 to p. 11-34, line 2.

additional points identified by operations as being needed to provide key visibility into the GT system.¹³⁶⁵

3.10.6.2 Visibility Into Local Transmission Conditions is Critical

TURN claims that by the beginning of the 2023-2026 rate case period, “PG&E should be addressing relatively lower risk assets compared to those it targeted earlier in the program.”¹³⁶⁶ This argument misses the key reason for achieving a high degree of SCADA visibility: abnormal conditions that cause incidents can occur anywhere on the system. High visibility allows quicker detection and quicker response thereby greatly increasing safety.

PG&E believes having 100 percent visibility into the local transmission system is necessary to support safe operations and enable the GTCC to actively monitor all parts of the GT system. Currently, PG&E has completed SCADA installations on the backbone transmission system and at other key monitoring locations to support the OPS and to reduce the span of MAOP visibility between backbone monitoring locations and local transmission stations. While PG&E has targeted the most impactful locations on the transmission system first, visibility is needed at all local transmission stations to identify and respond to abnormal operating conditions that may impact downstream distribution systems.¹³⁶⁷

3.10.6.3 RSE Scores Should Not Be The Sole Criteria For this Program

TURN’s sole focus on RSE scores is similar to the Distribution SCADA Visibility Program. TURN’s reliance on its flawed RSE analysis is addressed in Sections 2.3 and 3.2.2 of this opening brief.¹³⁶⁸

Finally, as discussed in Section 3.10.5.3 above, the opinions of TURN’s witness Jonathan Lesser should be accorded lower weight than the judgment of PG&E’s witness Dan Menegus,

¹³⁶⁵ PG&E-16-E, p. 11-34, lines 13-23.

¹³⁶⁶ TURN-02, p. 126, lines 9-16.

¹³⁶⁷ PG&E-16-E, p. 11-35, lines 8-19.

¹³⁶⁸ PG&E-16-E, p. 11-31, lines 13-17.

given Mr. Menegus’ extensive qualifications and experience, and Dr. Lesser’s lack of experience or qualifications related to gas operations.

3.10.7 Gas Transmission Capacity for Load Growth – Capital (MAT 73A)

Capacity Projects install GT facilities to meet non-customer specific demand growth. Examples of capacity projects include constructing new gas pipelines (including parallel lines), increasing regulating station capacity, and adding new regulating stations. The need for new transmission capacity projects is driven by demand growth from increasing population, higher commercial and industrial loads, and increases in gas usage from factors such as space additions to existing housing. Growth within PG&E’s system can be both general and highly localized. While load growth typically happens on distribution systems, this growth affects hydraulically connected transmission capacity both upstream and downstream.¹³⁶⁹

If enough customer load growth were to occur in a certain area, transmission capacity in that area would become constrained—that is, unable to provide sufficient gas to satisfy customer demands at design day (peak hour) conditions. To address the risk of loss of supply, such constraints must be relieved by reinforcing the transmission system with new capacity before design day conditions occur. PG&E monitors and forecasts load growth to anticipate such constraints so it can proactively reinforce the transmission system. As with new business, growth driven pipeline capacity projects can take several years to design, permit, and construct, so they are initiated well before the forecasted growth materializes.¹³⁷⁰

TURN is the only party that addresses this program and proposes:

¹³⁶⁹ PG&E-16-E, p. 11-36, lines 1-12.

¹³⁷⁰ PG&E-16-E, p. 11-36, lines 13-23.

TABLE 3-64
GAS TRANSMISSION CAPACITY FOR LOAD GROWTH (MAT 73A): PG&E’S CAPITAL FORECAST AND PARTIES RECOMMENDED REDUCTIONS (\$000s)^(a)

Party	2020 Rec.	2021	2022	2023	2024	2025	2026
PG&E	\$10,049	\$22,350	\$8,232	\$8,589	\$8,803	\$9,050	\$9,330
TURN				\$(2,561)			
(a) PG&E-16-E, p. 11-46, Table 11-10, line 1 (2020-2022 recorded and forecast costs); PG&E-3-ES, p. v (2023-2026 forecasts); PG&E-16-E, p. 11-7, Table 11-4, line 1 (TURN’s recommendation).							

TURN’s proposed reductions¹³⁷¹ are based on the use of a three-year 2018-2020 average of recorded capital expenditures, less 50 percent, rather than PG&E’s proposed forecast methodology using the average of 2017-2019 recorded capital expenditures, escalated, less 50 percent.¹³⁷² TURN also asserts that PG&E “could avoid the need for additional transmission [capacity] entirely in the near future”¹³⁷³ based on extrapolating PG&E’s success in leveraging the use of alternatives to capacity expansion using peak-shaving and use of liquified natural gas (LNG) and compressed natural gas (CNG) support to address all instances of future transmission capacity demand growth.¹³⁷⁴

3.10.7.1 PG&E’s Forecast is Reasonable

To develop the 2023 GRC capacity forecast for MAT 73A, PG&E prepared a program level forecast, by utilizing a three-year average of recorded costs (2017-2019), and dividing that forecast by 50 percent, escalated. The 50 percent reduction represents the level of uncertainty that PG&E has in projects being identified during the 2023 GRC period and is reflective of the cost necessary to build capacity on an as-identified basis. The 50 percent reduction factor is based on subject matter expertise of PG&E’s GSP department, as a result of hydraulic modeling to estimate capacity growth on the gas transmission system.¹³⁷⁵ The forecast did not identify

¹³⁷¹ TURN-07, p. 48, lines 12-21.

¹³⁷² PG&E-16-E, p. 11-36, lines 26-31.

¹³⁷³ TURN-07, p. 48, lines 4-6.

¹³⁷⁴ PG&E-16-E, p. 11-37, lines 19-25.

¹³⁷⁵ PG&E-16-E, p. 11-38, line 26 to p. 11-39, line 7.

any specific capacity projects for growth for the 2023-2026 GRC period since at the time of filing there was not sufficient data for such analysis to be performed, and there was still too much uncertainty around the growth of natural gas demand in the GRC forecast period.¹³⁷⁶

TURN does not dispute the methodology of this approach. TURN argues, however, that PG&E should have used the 2018-2020 recorded costs, less 50 percent instead of PG&E's proposed average use of 2017-2019 recorded costs, escalated, less 50 percent.¹³⁷⁷ As PG&E explained "PG&E prepared its 2023 forecast for MAT 73A at the end of 2020 in preparation for filing this GRC. Therefore, PG&E used the previous three-years of available recorded data to inform the forecast (2017-2019)."¹³⁷⁸

Subsequent information, however, allows this dispute to be resolved. Since the forecast was developed and filed in June 2021, PG&E has identified four transmission capacity projects required to meet forecast load growth for the 2023-2026 period.¹³⁷⁹ Current project estimates are between \$30 million and \$55 million.¹³⁸⁰ PG&E's 2023-2026 forecast for MAT 73A is \$34.6 million, representative of the low-end of potential project costs that PG&E may incur. If PG&E was to use a three-year average of 2018-2020 recorded costs, the 2023-2026 forecast would be approximately \$25.5 million. In this scenario, PG&E would be significantly underfunded to perform capacity investments that maintain uninterrupted service to customers.¹³⁸¹ The Commission should therefore adopt PG&E's forecast for MAT 73A.

¹³⁷⁶ PG&E-16-E, p. 11-38, lines 26-30.

¹³⁷⁷ PG&E-16-E, p. 11-37, lines 13-18.

¹³⁷⁸ PG&E-16-E, p. 11-38, lines 9-11.

¹³⁷⁹ PG&E-16-E, PG&E's response to Data Request TURN_041-Q06, dated 10/28/21 and attachment TURN_041-Q06Atch01, pp. AppA-375 to AppA-377.

¹³⁸⁰ *Id.*

¹³⁸¹ PG&E-16-E, p. 11-39, lines 17-25.

3.10.7.2 PG&E Cannot Ignore the Need for Additional Capacity Projects

TURN asserts that PG&E “... could avoid the need for additional transmission [capacity projects] entirely in the near future”¹³⁸² and that the “long-term trend toward reduced gas consumption is all but eliminated the need for capacity upgrades of this nature.”¹³⁸³ However, these claims overstate PG&E’s ability to avoid new capacity.

Prior to the start of any capacity project, PG&E’s Gas System Planning department evaluates the forecast capacity demand and identifies whether the system hydraulics can be manipulated to meet demand through cheaper alternatives. In many cases, a permanent capacity project is the recommended option due to reliability or safety concerns.¹³⁸⁴ In some instances, PG&E is able to leverage alternative measures to capacity expansion, such as the use of “peak-shaving” and distribution load shifting, and manual field operations.¹³⁸⁵ However, these opportunities are limited. In many cases, peak-shaving and distribution load shifting can only be used in scenarios where the forecast capacity demand increases, and system designs are a match to support a change in hydraulic configurations. For many of the identified areas that require capacity reinforcements, peak-shaving and distribution load shifting are not viable options to meet forecast customer demand.¹³⁸⁶

TURN is also incorrect that “the long-term trend toward reduced gas consumption is all but eliminating the need for capacity upgrades... .”¹³⁸⁷ PG&E does not have enough data on the potential impacts of decarbonization to accurately forecast capacity the specific locations where capacity reductions may materialize across PG&E’s service territory. However, PG&E

¹³⁸² TURN-07, p. 48, lines 4-6.

¹³⁸³ TURN-07, p. 46, lines 17-19.

¹³⁸⁴ PG&E-16-E, p. 11-40, line 29 to p. 11-41, line 3.

¹³⁸⁵ PG&E provided examples in PG&E-16-E, PG&E’s response to Data Request TURN_003-Q05, dated 8/27/21, pp. AppA-378 to AppA-379.

¹³⁸⁶ PG&E-16-E, p. 11-40, lines 7-19.

¹³⁸⁷ TURN-07, p. 46, lines 17-19.

continues to see load growth occur in a number of areas not currently affected by policies restricting gas usage.¹³⁸⁸

For example, PG&E has observed demand growth on the local transmission system that supplies the Napa Valley region due to new commercial and residential growth. Additionally, PG&E has existing capacity constraints on the local transmission system that serves the Peninsula in San Francisco and San Mateo Counties. Currently, PG&E manages this demand through high-risk manual operation (throttling mainline valves) during a design day. However, PG&E forecasts this system is at risk of not meeting design day specifications in the event of pressure reductions taken due to integrity anomalies identified.¹³⁸⁹

PG&E along with agencies such as the California Energy Commission are working to develop granular, location based future gas demand forecasts under peak day conditions to reflect the impacts of decarbonization policies. As a result, PG&E is carefully monitoring changes to future capacity network plans to ensure that design day standards are maintained while evaluating the need for long term system enhancements to meet demand. PG&E is addressing the uncertainty of future gas demand by leveraging the use of CNG, liquified natural gas (LNG), and manual field operations to ensure system reliability in localized, or constrained regions, and in some cases defer the installation of additional parallel pipelines or other costly enhancements that may be stranded assets if demand drops in the future. In the case of PG&E's Capacity for Load Growth program, this uncertainty is the driver for why a 50 percent reduction was included in forecast calculations to account for the uncertainty in future gas capacity growth.¹³⁹⁰

¹³⁸⁸ PG&E-16-E, p. 11-41, lines 7-15.

¹³⁸⁹ PG&E-16-E, p. 11-41, lines 16-24.

¹³⁹⁰ PG&E-16-E, p. 11-41, line 25 to p. 11-42, line 7.

3.11 Gas Technology

Exhibit PG&E-03, Chapter 12 presents PG&E's forecast capital and expense activities for Gas Technology programs. Gas Information Technology (IT) initiatives are designed to enhance PG&E's ability to operate the gas system safely and efficiently with projects that assist in identifying abnormal system conditions, reducing response time to planned and unplanned events, integrating data needed throughout work processes, and delivering solutions that give our employees greater and faster access to the information they need.¹³⁹¹

PG&E's Corrected Forecast for GD expense is \$12.588 million.¹³⁹² The GD expense forecast is uncontested. PG&E's Corrected Forecast for GT&S expense is \$2.990 million.¹³⁹³ The GT&S expense forecast is uncontested.

PG&E's JCE forecast for Gas Technology expense is \$17.825 million.¹³⁹⁴

PG&E's Corrected Forecast for GD capital expenditures is \$14.387 million in 2021, \$11.018 million in 2022, and \$11.217 million in 2023, \$11.421 million in 2024, \$11.630 million in 2025, and \$11.845 million in 2026.¹³⁹⁵ PG&E's JCE forecast for capital expenditures forecast is \$14.826 million in 2021, \$12.794 million in 2022, and \$13.574 million in 2023, \$13.840 million in 2024, \$13.912 million in 2025, and \$13.989 million in 2026.¹³⁹⁶ The GD capital forecast is uncontested.

¹³⁹¹ PG&E-03, p. 12-1, lines 6-16.

¹³⁹² PG&E-16-E, p. 2-5, Table 2-1, line 7.

¹³⁹³ PG&E-3-ES, p. iv. which reflects PG&E's rebuttal forecast updated with corrected escalation factors.

¹³⁹⁴ PG&E-64, p. 3-1, Table 3A-1, line 38.

¹³⁹⁵ PG&E-16-E, p. 2-7, Table 2-3, line 7 (2021); p. 2-9, Table 2-5, line 7 (2022); PG&E-3-ES, p. v, which reflects PG&E's rebuttal forecast updated with corrected escalation factors. (2023-2026).

¹³⁹⁶ PG&E-64, p. 3-6, Table 3B-1, line 24 (2023); p. 3-10, Table 3B-2, line 24 (2022); and p. 3-14, Table 3B-3, line 24 (2021). Forecasts for 2024-2026 are not included in the JCE but are provided here for reference.

PG&E's Corrected Forecast for GT&S capital expenditures is \$13.414 million in 2021, \$11.538 million in 2022, \$11.782 million in 2023, \$12.033 million in 2024, \$12.291 million in 2025, and \$12.556 million in 2026.¹³⁹⁷ PG&E's JCE forecast for capital expenditures is \$13.823 million in 2021, \$13.397 million in 2022, \$14.258 million in 2023, \$14.583 million in 2024, \$14.703 million in 2025, and \$14.828 million in 2026.¹³⁹⁸ The GT&S capital forecast is uncontested.

Given that no party contested PG&E's expense or capital programs for Gas Technology, PG&E requests that the Commission adopt PG&E's forecasts and programs as set forth in Exhibit PG&E-03, Chapter 12.

3.12 Other Gas Operations Support

Exhibit PG&E-03, Chapter 13 presents expense and capital forecasts that enable Gas Operations to: comply with laws and regulations to protect the environment; qualify the workforce; maintain accurate maps and records of assets; provide services to noncore gas customers; equip employees with the tools and equipment they need to do their jobs safely and efficiently; and build and support the Gas Operations workforce.¹³⁹⁹

PG&E's Corrected Forecast for GD expense is \$72.548 million.¹⁴⁰⁰

PG&E's Corrected Forecast for GT&S expense forecast is \$57.055 million.¹⁴⁰¹

PG&E's JCE forecast for Gas Operations Support is \$129.604 million.¹⁴⁰²

¹³⁹⁷ PG&E-16-E, p. 2-8, Table 2-4, line 6 (2021); p. 2-10, Table 2-6, line 6 (2022); PG&E-3-ES, p. v, which reflects PG&E's rebuttal forecast updated with corrected escalation factors. (2023-2026).

¹³⁹⁸ PG&E-64, p. 3-6, Table 3B-1, line 25 (2023); p. 3-10, Table 3B-2, line 25 (2022); and p. 3-14, Table 3B-3, line 25 (2021). Forecasts for 2024-2026 are not included in the JCE but are provided here for reference.

¹³⁹⁹ PG&E-03, p. 13-1, lines 11-16.

¹⁴⁰⁰ PG&E-16-E, p. 13-3, Table 13-1, line 9.

¹⁴⁰¹ PG&E--3-ES, p. iv. which reflects PG&E's rebuttal forecast updated with corrected escalation factors.

¹⁴⁰² PG&E-64, p. 3-1, Table 3A-1, lines 39-48.

PG&E's Corrected Forecast for GD capital expenditures is \$37.543 million in 2021, \$29.728 million in 2022, \$26.042 million in 2023, \$24.351 million in 2024, \$19.251 million in 2025, and \$18.722 million in 2026.¹⁴⁰³ PG&E's JCE forecast for capital expenditures is \$39.392 million in 2021, \$33.084 million in 2022, \$29.723 million in 2023 \$27.327 million in 2024, \$21.363 million in 2025, and \$20.417 million in 2026.¹⁴⁰⁴

PG&E's Corrected Forecast for GT&S capital expenditures is \$(69.698) million in 2021, \$5.892 million in 2022, \$5.987 million in 2023. \$6.137 million in 2024, \$21.875 million in 2025, and \$22.553 million in 2026 ¹⁴⁰⁵ PG&E's JCE forecast for capital expenditures forecast is \$(86.244) million in 2021, \$7.931 million in 2022, \$7.440 million in 2023 \$7.222 million in 2024, \$23.992 million in 2025, and \$24.113 million in 2026.¹⁴⁰⁶

Of the 18 expense MATs related to Gas Operations Support, only 5 are disputed. Similarly, for the 5 capital MATs, only 3 are disputed. The undisputed programs, associated MATs, and corresponding expense and capital forecasts are identified in Appendix A. In the remainder of this Section 3.12, we address the disputed programs.

TABLE 3-65
SUMMARY OF ISSUES ADDRESSED IN SECTION 3.12

Section	Disputed Program	Impacted MATs
3.12.1	Butte Rebuild	Capital and Expense (MAT LXA and MAT 3QA)
3.12.2	CEMA Straight Time Labor Program	Expense and Capital (MAT 21# and AB #)

¹⁴⁰³ PG&E-16-E, p.13-22, Table 13-9, line 7 (2021 and 2022) and PG&E-3-ES, p. v, which reflects PG&E's rebuttal forecast updated with corrected escalation factors. (2023-2026).

¹⁴⁰⁴ PG&E-64, p. 3-6, Table 3B-1, lines 26, 27 and 29 (2023); p. 3-10, Table 3B-2, lines 26, 27 and 29 (2022); and p. 3-14, Table 3B-3, lines 26, 27 and 29 (2021). Forecasts for 2024-2026 are not included in the JCE but are provided here for reference.

¹⁴⁰⁵ PG&E-16-E, p.13-22, Table 13-10, line 7 (2021 and 2022) and PG&E-3-ES, p. v, which reflects PG&E's rebuttal forecast updated with corrected escalation factors. (2023-2026).

¹⁴⁰⁶ PG&E-64, p. 3-6, Table 3B-1, lines 28 and 30 (2023); p. 3-10, Table 3B-2, lines 28 and 30 (2022); and p. 3-14, Table 3B-3, lines 28 and 30 (2021). Forecasts for 2024-2026 are not included in the JCE but are provided here for reference.

Section	Disputed Program	Impacted MATs
3.12.3	Gas R&D and Deployment	Expense (MWC GZ)
3.12.4	Other Gas Operations Support	Expense (MAT AB#)
3.12.5	StanPac	Expense (MAT 34A)
3.12.6	StanPac	Capital (MAT 44A)

3.12.1 Butte Rebuild – Capital and Expense (MAT LXA and MAT 3QA)

These MWCs are intended for catastrophic events, and activities include gas restoration and rebuild efforts attributed to major events, in declared counties, made by an official authority – either the US President or the Governor of California.¹⁴⁰⁷ The Community Rebuild Program is also discussed in detail in Exhibit PG&E-04, Chapter 23. The Community Rebuild Program reflects forecast expenses (MAT LXA) and capital expenditures (MAT 3QA) associated with replacing PG&E’s infrastructure for the Town of Paradise.¹⁴⁰⁸ TURN and Cal Advocates addresses this program and propose:

¹⁴⁰⁷ PG&E-16-E, p. 13-9, lines 20-24.

¹⁴⁰⁸ PG&E-04, Ch. 23.

TABLE 3-66
COMMUNITY REBUILD (MATS LXA AND 3QA: PG&E’S CAPITAL FORECAST AND
PARTIES RECOMMENDED REDUCTIONS (\$000s)

Party	2020 Rec.	2021	2022	2023	2024	2025	2026
Expense (LXA)							
PG&E ^(a)	\$--	\$1,500	\$2,859	\$2,912			
Cal Advocates ^(b)				\$(2,912)			
TURN ^(b)				\$(2,912)			
Capital (3QA)							
PG&E ^(a)	\$--	\$32,110	\$24,187	\$17,810	\$15,868	\$10,515	\$9,727
Cal Advocates ^(c)		\$(32,110)	\$(24,187)	\$(17,810)	\$(15,868)	\$(10,515)	\$(9,727)
TURN ^(c)							
(a) PG&E-16-E, p. 13-20, Table 13-7, line 6 (2020-2023 recorded and forecast expenses); PG&E-16-E, p. 13-22, Table 13-9, line 5 (2020-2022 recorded and forecast capital); PG&E-3-ES, p. v (2023-2026 forecast capital). (b) PG&E-64, p. JCE 3-156 (Cal Advocates’ recommendation); PG&E-16-E, p. 13-3, Table 13-1, line 6 (TURN’s recommendation). (c) PG&E-64, p. JCE 4-142 (Cal Advocates’ and TURN’s recommendations). Parties’ recommend no funding for this program. PG&E has adjusted Parties’ recommended reductions to match PG&E’s Corrected Forecast so that the funding level is \$0.							

Cal Advocates also recommends the removal of all costs for years 2019-2020. “Cal Advocates recommends that the costs for the Community Rebuild Program continue to be booked into CEMA for 2023 and beyond, and that 2019 and 2020 recorded CEMA capital costs, totaling \$155.853 million, that PG&E has included in its RO model and within its GRC request, be removed.”¹⁴⁰⁹ TURN recommends disallowing “rate recovery of any and all costs of PG&E’s continuing efforts to repair facilities and restore service in areas impacted by the Camp Fire...”¹⁴¹⁰ TURN’s basis for not allowing recovery of costs is due to “the utility’s role in causing the fire and, by extension, creating the need for the ‘rebuild’.”¹⁴¹¹

PG&E disagrees with Cal Advocates and TURN’s recommendations. Please see Section 4.23 of this brief for further discussion.

¹⁴⁰⁹ CALPA-05, p. 5, lines 8-13.

¹⁴¹⁰ TURN-13, p. 1, lines 8-11.

¹⁴¹¹ TURN-13, p. 1, lines 25-27.

3.12.2 CEMA Straight Time Labor Program – Expense and Capital (MAT 21# and AB #)

PG&E requests recovery of straight time labor associated with Catastrophic Event Memorandum Account (CEMA) eligible activities as these costs are incremental to base rates because the GRC and GT&S forecasts are reduced commensurate with the cost of CEMA activities. Please see Exhibit PG&E-04, Chapter 6, for more details around the CEMA straight time labor request. PG&E's CEMA straight time labor request for Gas Operations is forecast in MAT 21# for capital and MAT AB# for expense.¹⁴¹² For the distribution portion of MAT AB# PG&E's 2023 forecast is \$16.4 million.¹⁴¹³ For the GT&S portion of MAT AB# PG&E's 2023 forecast is \$18.0 million.¹⁴¹⁴ For MAT 21#, PG&E's capital expenditure forecast is \$2.1 million in 2023, \$2.1 million in 2024, \$2.2 million in 2025, and \$2.3 in 2026.¹⁴¹⁵ TURN and Cal Advocates addresses this program and propose:

¹⁴¹² PG&E-16-E, p. 13-11, lines 9-15.

¹⁴¹³ PG&E-16-E, p. 13-3, Table 13-1, line 1.

¹⁴¹⁴ PG&E-3-ES, p. iv.

¹⁴¹⁵ PG&E-3-ES, p. v.

TABLE 3-67
OTHER GAS OPERATIONS SUPPORT (MATS AB# AND 21#): PG&E'S CAPITAL AND
EXPENSE FORECAST AND PARTIES RECOMMENDED REDUCTIONS (\$000s)

Party	2020 Rec.	2021	2022	2023	2024	2025	2026
Expense (AB#)							
PG&E ^(a)	\$26,441	\$27,525	\$33,284	\$34,368			
TURN – CEMA STL ^(b)				\$(2,878)			
TURN – Alternative Energy Program ^(c)				\$1,300			
Capital (21#)							
PG&E ^(d)	\$12,267	\$2,017	\$2,051	\$2,098	\$2,151	\$2,200	\$2,251
Cal Advocates ^(e)				\$(2,098)	\$(2,151)	\$(2,200)	\$(2,251)
TURN ^(e)				\$(2,098)	\$(2,151)	\$(2,200)	\$(2,251)

(a) Includes recorded and forecast costs for both GD and GT. PG&E-16-E, p. 13-20, Table 13-7, line 1 (2020-2023 recorded and forecast GD expense); p. 13-21, Table 13-8, line 2 (2020-2022 recorded and forecast GT expense); PG&E-3-ES, p. iv (2023 forecast GT expense)

(b) Represents TURN's recommended reduction of \$2.9 million for CEMA Straight Time Labor. PG&E-16-E, p. 13-3, Table 13-1, line 1 and p. 13-4, Table 13-2, line 2 (\$2,207 + \$671 = \$2,878).

(c) Represents TURN's recommended increase of \$1.3 million for PG&E's Alternative Energy Program. TURN-07, p. 50, lines 1-4. TURN's recommendation is discussed in Section 3.12.4 of this brief.

(d) PG&E-64, p. JCE 4-145 (Cal Advocates' and TURN's recommendations). Parties' recommend no funding for this program. PG&E has adjusted Parties' recommended reductions to match PG&E's Corrected Forecast so that the funding level is \$0.

(e) PG&E-16-E, p. 13-5, Table 13-3, line 2 showing Parties' recommended reductions for 2023. Parties' recommend no funding for CEMA Straight Time Labor recorded in MAT 21#. CALPA-03, p. 18, lines 9-18 and TURN-12, p. 1, line 9.

TURN concludes that the cost of employee straight time typically included in PG&E's CEMA applications, as in previous applications, is not an incremental CEMA cost. Those labor hours are already included in existing rates.¹⁴¹⁶ TURN recommends that the Commission deny PG&E's request for a separate straight time balancing account to be included in the GRC proceeding. Any further consideration of reimbursing employee straight time costs for a CEMA claim should take place in a CEMA proceeding, not the GRC.¹⁴¹⁷

¹⁴¹⁶ TURN-12, p. 1, line 9.

¹⁴¹⁷ TURN-12, p. 3, lines 11-14.

Cal Advocates proposes 2021-2023 capital reductions to MAT 21# of \$2.0 million, \$2.0 million and \$2.1 million, respectively. Cal Advocates does not address the expense forecast for CEMA straight time labor in MAT AB#. ¹⁴¹⁸ PG&E disagrees with Cal Advocates' and TURN's recommendations. Please see Section 4.6.3 of this brief for further discussion.

3.12.3 Gas R&D and Deployment – Expense (MAT GZA)

The purpose of the R&D and Deployment Program is to detect, develop, test, and introduce new methods and technologies into PG&E's Gas Distribution and Transmission operations to improve gas safety, reliability, and efficiency. ¹⁴¹⁹ The R&D and Deployment team has defined seven priorities that address the major threats for each Asset Family as identified in Gas Operations' Risk Register, and that support their mitigation measures: (1) extending the safe operational lifetime of our pipelines; (2) understanding the condition of PG&E's assets; (3) developing proactive, as opposed to reactive, operations; (4) reinventing leak management; (5) eliminating dig ins; (6) improving construction methods; and (7) decarbonizing the gas system. While these priorities help guide R&D and Deployment, efforts undertaken on a year-to-year basis vary based on risks to the Company's gas organization and collective needs of the collaborations and consortia to which PG&E contributes. ¹⁴²⁰ TURN and Cal Advocates address this program and propose:

¹⁴¹⁸ CALPA-03, p. 18, lines 9-18.

¹⁴¹⁹ PG&E-03, p. 13-19, lines 6-9.

¹⁴²⁰ PG&E-03, p. 13-20, lines 12-23.

TABLE 3-68
GAS R&D DEPLOYMENT (MAT GZA): PG&E’S CAPITAL FORECAST AND PARTIES
RECOMMENDED REDUCTIONS (\$000s)

Party	2020 Rec.	2021	2022	2023
PG&E – GD ^(a)	\$3,290	\$3,488	\$3,592	\$5,850
PG&E-GT ^(a)	\$2,049	\$3,085	\$3,177	\$5,647
PG&E – Total	\$5,339	\$6,573	\$6,769	\$11,497
Cal Advocates – GD ^(b)				\$(2,269)
Cal Advocates - GT ^(b)				\$(2,888)
Cal Advocates - Total				\$(5,157)
TURN – GD ^(b)				\$(2,084)
TURN - GT ^(b)				\$(2,002)
TURN – Total				\$(4,086)
(a) PG&E-16-E, p. 13-20, Table 13-7, line 5 (2020-2023 recorded and forecast GD expense); p. 13-21, Table 13-8, line 10 (2020-2022 recorded and forecast GT expense); PG&E-3-ES, p. iv (2023 forecast GT expense). (b) PG&E-64, p. JCE-154.				

Cal Advocates claims that its proposed reduction is justified given significantly lower 2021 recorded levels and six-year average expenses.¹⁴²¹ TURN recommends that PG&E’s Contributions to Collaborations and Consortiums “Other” category should be held to the last recorded year level of \$1,777,248. This results in a reduction of \$4,085,581.¹⁴²²

PG&E disagrees with Cal Advocates’ recommendation because PG&E’s forecast R&D growth will aid in its efforts to expand beyond the traditional consortia, allow the utility to support the advancement and deployment of new technologies, and optimize innovation especially in the context of decarbonization. The level of funding recommended by Cal Advocates is not enough for PG&E to reach its goals including for pipeline integrity and methane reduction. For each rate case period, new technologies are evaluated and considered to be added as sub programs to the R&D portfolio.¹⁴²³

¹⁴²¹ CALPA-03, p. 17, lines 2-10.

¹⁴²² TURN-05, pp. 13-14.

¹⁴²³ PG&E-16-E, p. 13-14, lines 3-14; PG&E-16-E, PG&E’s response to Data Request TURN_109-Q005, dated 2/16/22, p. AppA-384.

The level of funding recommended by TURN is not enough for PG&E to continue to grow the program. In terms of the “Other” forecast for Contributions to Collaborations and Consortia—PG&E forecasts to continue to grow its R&D efforts beyond the traditional industry consortia. This investment includes support to deployment of new technologies within its operations to ensure that their benefits are rapidly captured. It will also include broader collaborations to accelerate and optimize the sourcing of innovation especially in the context of decarbonization.¹⁴²⁴

3.12.4 Other Gas Operations Support (MAT AB#)

The expense MAT AB# comprises general support expenses for both Gas Distribution and GT&S related to various programs: Engineer Rotation Development Program (ERDP); Gas Consulting Contracts; GO Data Management; and Gas Asset Strategy’s Alternative Energy Program.¹⁴²⁵ In addition, as discussed in Section 3.12.2 above, PG&E’s expense forecast for CEMA straight time labor is also included in MAT AB#. TURN’s and Cal Advocates’ recommended disallowances for CEMA straight time labor in MAT AB# are addressed in that section.

For the distribution portion of MAT AB# PG&E’s 2023 forecast is \$16.4 million.¹⁴²⁶ For the GT&S portion of MAT AB# PG&E’s 2023 forecast is \$18.0 million.¹⁴²⁷ TURN is the only party that addresses this program and proposes a 2023 expense increase of \$1.3 million¹⁴²⁸ to PG&E’s total MAT AB# forecast of \$34.4 million for the Alternative Energy Program.

¹⁴²⁴ PG&E-03, WP 13-10, Workpaper Table 13-10.

¹⁴²⁵ PG&E-03, p. 13-29, line 22 to p. 13-30, line 27.

¹⁴²⁶ PG&E-16-E, p. 13-3, Table 13-1, line 1.

¹⁴²⁷ PG&E-3-ES, p. iv.

¹⁴²⁸ TURN’s recommended increase is split equally between GD and GT&S MAT AB#.

PG&E supports TURN's proposal. The Alternative Energy Program provides an incentive for customers to replace their gas equipment and appliances with electric.¹⁴²⁹ This effort aligns with our efforts to reduce our overall gas footprint while reducing risk in the system. TURN recommends "that PG&E be authorized twice its requested amount, or \$2.6 million annually, to pursue the Alternative Energy Program in 2023 and the years following, subject to reporting requirements that would help inform the state's future efforts at coordinating customer electrification with opportunities to reduce gas system investments."¹⁴³⁰ PG&E agrees with TURN's recommendation to increase funding for the Alternative Energy Program as it supports PG&E's efforts towards reducing the overall gas footprint while reducing risk on the system.¹⁴³¹

While PG&E agrees with TURN's recommendation to increase funding for the Alternative Energy Program, PG&E does not agree the detailed reporting recommended by TURN is necessary as this program is still immature. If the Commission believes reporting may be useful now or in the future, PG&E urges the Commission reject TURN's detailed reporting proposal and instead direct Commission staff to host a workshop with parties to develop the appropriate topics for reporting and timing for implementation.¹⁴³²

3.12.5 StanPac -- Expense (MAT 34A)

The StanPac pipeline runs from Rio Vista to Richmond, and the entity is 6/7 owned by PG&E and 1/7 by Chevron. PG&E operates and maintains the StanPac transmission pipeline. The MATs for StanPac are MAT 34A for expense and MAT 44A for capital.¹⁴³³ MAT 34A is addressed in this Section 3.12.6 and MAT 44A is addressed in Section 3.12.7 below. StanPac

¹⁴²⁹ PG&E-03, p. 13-30, lines 20-23.

¹⁴³⁰ TURN-07, p. 50, lines 1-4.

¹⁴³¹ PG&E-16-E, p. 13-16, lines 19-21.

¹⁴³² PG&E-16-E, p. 13-16, lines 19-27.

¹⁴³³ PG&E-03, p. 13-10, line 27 to p. 13-11, line 12.

expense (MAT 34A) covers any gas expense project on a StanPac line. PG&E's 2023 expense forecast is based on a three-year average (2018-2020), adjusted to remove one-time historical projects and include project-specific adders related to programs in the Transmission Pipe Asset Family. TURN is the only party that addresses this program and proposes:

TABLE 3-69
STAN PAC EXPENSE (MAT 34A): PG&E'S EXPENSE FORECAST AND PARTIES
RECOMMENDED REDUCTIONS (\$000s)^(a)

Party	2020 Rec.	2021	2022	2023
PG&E	\$1,159	\$3,923	\$4,432	\$3,012
TURN				\$(507)
(a) PG&E-16-E, p. 13-8, Table 11-8, line 3 (2020-2022 recorded and forecast costs); PG&E-3-ES, p. iv (2023 forecast); PG&E-64, p. JCE 3-147 (TURN's recommendation).				

TURN makes no recommendation on the three-year average component of the MAT 34A forecast. However, as described in the rebuttal testimony of PG&E witness Barnes,¹⁴³⁴ TURN makes recommendations associated with the adder projects for the following Transmission Pipe Asset Family programs: Traditional In-Line Inspection (ILI) (\$0.3 million reduction); Internal Corrosion Direct Assessment (ICDA) (\$0.1 million reduction); and Strength Testing (\$0.1 million reduction).¹⁴³⁵ PG&E disagrees with TURN's recommendation. As these StanPac project forecasts are based on the relevant Transmission Pipe Asset Family program cost calculators.¹⁴³⁶

3.12.6 StanPac -- Capital (MAT 44A)

StanPac capital covers any gas capital project on a StanPac line. PG&E's 2023-2026 capital forecast is based on a three-year average (2018-2020), adjusted to remove one-time

¹⁴³⁴ PG&E-16-E, Ch. 5.

¹⁴³⁵ PG&E-16-E, p. 13-17, lines 21-27.

¹⁴³⁶ PG&E-16-E, p. 5-78, lines 5-24.

historical projects and includes project-specific adders related to programs in the Transmission Pipe Asset Family.¹⁴³⁷ TURN is the only party that addresses this program and proposes:

TABLE 3-70
STAN PAC CAPITAL (MAT 44A): PG&E’S CAPITAL FORECAST AND PARTIES
RECOMMENDED REDUCTIONS (\$000s)^(a)

Party	2020 Rec.	2021	2022	2023	2024	2025	2026
PG&E	\$7,342	\$5,388	\$4,934	\$2,810	\$2,880	\$18,527	\$19,102
TURN				\$(77)			
(a) PG&E-16-E, p. 13-22, Table 13-10, line 5 (2020-2022 recorded and forecast costs); PG&E-3-ES, p. v (2023-2026 forecasts); PG&E-64, p. JCE 3-146 (TURN’s recommendation).							

TURN makes no recommendation on the three-year average component of the MAT 44A forecast. However, TURN makes recommendations associated with the adder projects described in the rebuttal testimony of PG&E Witness Barnes¹⁴³⁸ for the Transmission Pipe Asset Family Strength Testing and In-Line Inspection (ILI) Upgrade programs.

PG&E disagrees with TURN’s recommendation. As these StanPac project forecasts are based on the relevant Transmission Pipe Asset Family program cost calculators.¹⁴³⁹

The recommended funding level for 2023 is sufficient if the forecast is adjusted for the StanPac Transmission Pipe Asset Family Strength Testing adder projects as TURN’s recommendation reflects an increase. However, the recommended funding level for 2025-2026 is insufficient if the forecast is adjusted for the StanPac Transmission Pipe Asset Family Traditional ILI Upgrade adder projects. The rebuttal testimony of PG&E Witness Barnes in Exhibit PG&E-16-E, Chapter 5, describes why PG&E disagrees with the adjustments to both programs.¹⁴⁴⁰

¹⁴³⁷ PG&E-03, WP 13-48, Workpaper Table 13-25 Revised.

¹⁴³⁸ PG&E-16-E, Ch. 5.

¹⁴³⁹ PG&E-16-E, p. 5-78, lines 5-24.

¹⁴⁴⁰ PG&E-16-E, p. 13-19, lines 12-19.

3.13 New Business and Work at the Request of Others

Exhibit PG&E-03, Chapter 14 presents PG&E's forecast of Gas Operations' expense and capital expenditures for New Business (NB) and Work at the Request of Others (WRO). NB work consists of connecting new customers to PG&E's gas transmission (GT) or gas distribution (GD) systems, and WRO work consists of relocating PG&E's existing GT or GD facilities at the request of governmental agencies, customers, and other third parties.¹⁴⁴¹

PG&E's Corrected Forecast for GD expense is \$6.790 million.¹⁴⁴² PG&E's JCE forecast is \$7.595 million.¹⁴⁴³

PG&E's Corrected Forecast for GT&S expense is \$1.129 million.¹⁴⁴⁴ PG&E's JCE forecast is \$1.461 million.¹⁴⁴⁵

PG&E's Corrected Forecast for GD capital expenditures is \$167.223 million in 2021, \$199.449 million in 2022, \$198.982 million in 2023, \$190.803 million in 2024, \$195.578 million in 2025, and \$191.810 million in 2026.¹⁴⁴⁶ PG&E's JCE forecast for capital expenditures is \$175.772 million in 2021, \$222.689 million in 2022, \$222.878 million in 2023, \$208.106 million in 2024, \$208.338 million in 2025, and \$199.405 million in 2026.¹⁴⁴⁷

PG&E's Corrected Forecast for GT&S capital expenditures is \$36.060 million in 2021, \$29.384 million in 2022, \$23.916 million in 2023, \$24.520 million in 2024, \$25.195 million in

¹⁴⁴¹ PG&E-03, p. 14-1, lines 6-12.

¹⁴⁴² PG&E-16-E, p. 14-3, Table 14-1, line 8.

¹⁴⁴³ PG&E-64, p. 3-1, Table 3A-1, line 50.

¹⁴⁴⁴ PG&E-3-ES, p. iv. which reflects PG&E's rebuttal forecast updated with corrected escalation factors.

¹⁴⁴⁵ PG&E-64, p. 3-1, Table 3A-1, line 49.

¹⁴⁴⁶ PG&E-16-E, p.14-24, Table 14-10, line 16 (2021 and 2022) and PG&E-3-ES, p. v, which reflects PG&E's rebuttal forecast updated with corrected escalation factors. (2023-2026).

¹⁴⁴⁷ PG&E-64, p. 3-6, Table 3B-1, lines 32-33 (2023); p. 3-10, Table 3B-2, lines 32-33 (2022); and p. 3-14, Table 3B-3, lines 32-33 (2021). Forecasts for 2024-2026 are not included in the JCE but are provided here for reference.

2025, and \$25.941 million in 2026.¹⁴⁴⁸ PG&E’s JCE forecast for capital expenditures is \$44.523 million in 2021, \$40.609 million in 2022, \$30.603 million in 2023, \$27.884 million in 2024, \$27.181 million in 2025, and \$27.211 million in 2026.¹⁴⁴⁹

Of the 8 expense MATs related to Work at the Request of Others, only 1 is disputed. Similarly, for the 17 capital MATs, only 7 are disputed. The undisputed programs, associated MATs, and corresponding expense and capital forecasts are identified in Appendix A. In the remainder of this Section 3.13 we discuss the disputed programs.

**TABLE 3-71
SUMMARY OF ISSUES ADDRESSED IN SECTION 3.13**

Section	Disputed Program	Impacted MATs
3.13.1	Gas Transmission Expense Work at the Request of Others	Expense (MAT JTA)
3.13.2	Gas Distribution Capital New Business Program	Capital (MWC 29)
3.13.3	Gas Transmission (GT) New Business (NB) Program	Capital (MAT 26A)
3.13.4	Gas Transmission Work at the Request of Others Program –	Capital (MAT 83A)

3.13.1 Gas Transmission Expense Work at the Request of Others – Expense (MAT Code JTA)

PG&E’s GT “Work Requested by Others” (WRO) expense program encompasses work required by tariff, third-party requests, and franchise compliance. This work includes gas transmission non-plant relocations and alterations of gas facilities requested by others. Typical projects include valve frame and cover alterations for street widening projects, lowering transmission facilities to avoid a conflict with agency roadwork, adding mechanical protection such as a concrete cap over a pipeline crossing a highway, road, street, or other facility, and accommodating a project without requiring the re-location of the pipeline. This work is

¹⁴⁴⁸ PG&E-16-E, p.14-25, Table 14-11, line 3 (2021 and 2022) and PG&E-3-ES, p. v, which reflects PG&E’s rebuttal forecast updated with corrected escalation factors. (2023-2026).

¹⁴⁴⁹ PG&E-64, p. 3-6, Table 3B-1, lines 31 and 34 (2023); p. 3-10, Table 3B-2, lines 31 and 34 (2022); and p. 3-14, Table 3B-3, lines 31 and 34 (2021). Forecasts for 2024-2026 are included in the JCE but are provided here for reference.

generally required by City, County, State, or other jurisdictional agencies.¹⁴⁵⁰ PG&E is forecasting \$1.1 million for the 2023 test year based on an escalated five-year average of recorded costs from 2015 to 2019.¹⁴⁵¹ Cal Advocates is the only party that addresses this program and proposes:

TABLE 3-72
GAS TRANSMISSION WORK AT THE REQUEST OF OTHERS (MAT JTA): PG&E’S
EXPENSE FORECAST AND PARTIES RECOMMENDED REDUCTIONS (\$000s)^(a)

Party	2020 Rec.	2021	2022	2023
PG&E	\$288	\$658	\$674	\$1,129
Cal Advocates				\$(619)
(a) PG&E-16-E, p. 14-23, Table 14-8, line 1 (2020-2022 recorded and forecast costs); PG&E-3-ES, p. iv (2023 forecast); PG&E-64, p. JCE 3-165 (Cal Advocates’ recommendation).				

Cal Advocates bases its reduction on comparison to historic spending¹⁴⁵² and a claim that “PG&E did [not] provide any documentation to support the increase in expenses was due to any planned projects.”¹⁴⁵³ PG&E’s recommended funding level is reasonable based on the variability of externally driven work. PG&E originally began forecasting for WRO/NB in 2020, thus the five-year average is calculated based on 2015 through 2019. When 2020 recorded costs became available in 2021, it was determined that 2020 had been impacted by COVID-19 restrictions and were not consistent with historical costs. A decision was made to keep the forecast based on 2015-2019 and not use the 2020 actuals. PG&E determined the 2015-2019 time period to be the most accurate and inclusive of yearly variations.¹⁴⁵⁴ Cal Advocates’ proposal to reduce PG&E’s forecast is flawed for a number of reasons.

¹⁴⁵⁰ PG&E-03, p. 14-21, line 16 to p. 14-23, line 3.

¹⁴⁵¹ PG&E-3-ES, p. iv.

¹⁴⁵² CALPA-03, p. 20, lines 15–21.

¹⁴⁵³ CALPA-03, p. 20, lines 21–22.

¹⁴⁵⁴ PG&E-16-E, p. 14-12, lines 6-18.

First, Cal Advocates incorrectly represents PG&E's 2020 recorded expenses for MAT Code JTA. As shown in PG&E's opening workpapers, the recorded expenses for MAT Code JTA in 2020 are \$288,000.¹⁴⁵⁵ This is \$669,000 below the 5-year average from 2015 to 2019 of \$957,000. Thus, 2020 recorded costs are 70 percent below the 5-year average.¹⁴⁵⁶

Second, Cal Advocates use of 2021 data is improper. Recorded expenses for 2021 were not available to PG&E when determining the 2023 forecast prior to filing on June 30, 2021.¹⁴⁵⁷ The use of 2021 recorded data in this GRC is further discussed in Section 1.5 of this opening brief

Third, Cal Advocates' 6-year 2016-2021 average of yearly expenses¹⁴⁵⁸ is not representative because it selectively omits the high spending year of 2015 but includes the very low 2020 spending year that was impacted by COVID-19. Cal Advocates' six-year average uses 2016 to 2021 recorded expenses to determine their value of \$0.4 million. PG&E did not use 2020 recorded expenses based on its conclusion that 2020 was an anomalous year for gas transmission WRO expense work due to COVID-19 impacts. Given that 2020 was impacted by COVID-19, PG&E determined that the five-year average from 2015 to 2019 was the most accurate representation of the recorded expense variations that can occur within this program.¹⁴⁵⁹

Fourth, PG&E has provided sufficient evidence to support its forecast contrary to Cal Advocates' claim.¹⁴⁶⁰ PG&E's opening workpaper for MAT Code JTA provides recorded expenses for five years (2015–2019) and calculates the 2023 forecast by taking an average of

¹⁴⁵⁵ PG&E-03, WP 14-3, Table 14-3.

¹⁴⁵⁶ PG&E-16-E, p. 14-10, line 24 to p. 14-11, line 2.

¹⁴⁵⁷ PG&E-16-E, p. 14-11, lines 5-6.

¹⁴⁵⁸ CALPA-03, p. 20, line 18.

¹⁴⁵⁹ PG&E-16-E, p. 14-11, lines 5-14.

¹⁴⁶⁰ CALPA-03, p. 20, lines 20–21.

recorded expenses, and escalating the average into the test year, 2023.¹⁴⁶¹ PG&E has fully explained the basis for its forecast, why it chose the years 2015-2019 as being representative, and has explained why using 2020 and 2021 recorded cost is not reasonable.¹⁴⁶²

Finally, nowhere in PG&E’s testimony regarding MAT Code JTA did PG&E claim its increase in forecast was “due to any planned projects.” PG&E agrees that specific projects were not the basis for its forecast.¹⁴⁶³ Thus, Cal Advocates argument that “PG&E did [not] provide any documentation to support the increase in expenses was due to any planned projects” is not applicable.¹⁴⁶⁴

3.13.2 Gas Distribution Capital New Business Program – Capital (MWC 29)

GD New Business (NB) consists of installing gas infrastructure required to connect new customers to PG&E’s distribution system and to accommodate increased load from existing customers.¹⁴⁶⁵ The cost of installing new gas infrastructure is shared between PG&E and the customer requesting the service. The provisions of this cost sharing are detailed in PG&E’s gas tariff (Gas Rules 2, 15, and 16).¹⁴⁶⁶ Customers requesting new service are eligible for certain financial allowances or subsidies that are borne by ratepayers as specified in these rules. PG&E’s forecasts represent the net cost to ratepayers, including allowances and subsidies, after all customer contributions have been applied.¹⁴⁶⁷ MWC 29 consists of multiple MAT codes to track the various categories of New Business connections.¹⁴⁶⁸ As in previous GRCs, PG&E

¹⁴⁶¹ PG&E-3-E, WP 14-7, Workpaper Table 14-7.

¹⁴⁶² PG&E-16-E, p. 14-11, lines 18-23.

¹⁴⁶³ PG&E-16-E, p. 14-12, lines 1-3.

¹⁴⁶⁴ CALPA-03, p. 20, lines 21–22.

¹⁴⁶⁵ PG&E-03, p. 14-10, line 11 to p. 14-16, line 9.

¹⁴⁶⁶ PG&E-03, WP 14-30, WP 14-36, and WP 14-54.

¹⁴⁶⁷ PG&E-03, p. 14-10, line 16 to p. 4-11 line 2.

¹⁴⁶⁸ PG&E-03, p. 4-13, Table 14-7.

relies on the forecast of New Business connects by a third-party consultant, Rosen Consulting Group (RCG) to determine its forecast for MAT Code 29.¹⁴⁶⁹

Cal Advocates supports PG&E's forecasts for MWC 29, stating: "Cal Advocates analyzed PG&E proposed capital expenditures for 2021, 2022, and 2023. Cal Advocates examined historical averages for recorded 2016-2021 capital expenditures. PG&E's proposed expenditures are consistent with trends and historical averages."¹⁴⁷⁰ Accordingly Cal Advocates recommends no reductions for PG&E's forecasts in MWC 29.

TURN also addresses this program and proposes:

¹⁴⁶⁹ PG&E-03, p. 14-13, line 5 to p. 14-14, line 14.

¹⁴⁷⁰ CALPA-03, p. 22, lines 5-8.

TABLE 3-73
GAS DISTRIBUTION NEW BUSINESS PROGRAM (MWC 29): PG&E'S CAPITAL
FORECAST AND PARTIES RECOMMENDED REDUCTIONS (\$000s)

Party	2020 Rec.	2021	2022	2023	2024	2025	2026
PG&E MWC 29	\$132,286	\$88,190	\$118,694	\$126,209	\$121,282	\$90,662	\$114,434
TURN MWC 29 ^(a)				\$(15,997)			
PG&E ^(b)							
MAT 29#	\$7,613	\$6,268	\$8,272	\$8,796	\$8,453	\$8,410	\$7,976
MAT 29C	\$18,824	\$11,576	\$15,603	\$16,591	\$15,943	\$15,862	\$15,043
MAT 29D	\$23,848	\$19,159	\$25,825	\$27,460	\$26,388	\$26,253	\$24,898
MAT 29H	\$10,421	\$5,117	\$6,897	\$7,333	\$7,047	\$7,011	\$6,649
MAT 29I	\$6,326	\$5,153	\$6,945	\$7,385	\$7,097	\$7,060	\$6,696
MAT 29J	\$47,828	\$28,444	\$38,339	\$40,767	\$39,175	\$38,975	\$36,963
MAT 29M	\$17,426	\$12,473	\$16,813	\$17,877	\$17,179	\$17,091	\$16,209
Total MWC 29	\$132,286	\$88,190	\$118,694	\$126,209	\$121,282	\$90,662	\$114,434
TURN ^(b)							
MAT 29#							
MAT 29C				\$(3,005)	\$(3,807)	\$(4,059)	\$(3,060)
MAT 29D							
MAT 29H				\$(1,328)	\$(1,683)	\$(1,794)	\$(1,353)
MAT 29I				\$(1,338)	\$(1,694)	\$(1,807)	\$(1,362)
MAT 29J				\$(7,384)	\$(9,354)	\$(9,974)	\$(7,519)
MAT 29M				\$(3,238)	\$(4,102)	\$(4,374)	\$(3,297)
Total MWC 29				\$(16,293)	\$(20,639)	\$(22,009)	\$(16,591)

(a) TURN recommends a reduction of \$15.997 million in 2023 to MWC 29 (PG&E-64, p. JCE 3-160). This is based on PG&E's Corrected Forecast of \$126.209 million in 2023. TURN recommended reductions in its testimony for five individual MAT codes in MWC 29. The individual MAT recommendations were associated with PG&E's original MWC 29 forecast for 2023 that was \$126.957 million (PG&E-16-E, p. 14-5, Table 14-3, lines 1-7). TURN's original recommendations by MAT are shown in the lines below.

(b) TURN's recommended reductions to PG&E's original forecast by MAT. See PG&E-16-E, p. 14-24, Table 14-10, lines 1-7 (2020-2023 recorded and forecast costs); PG&E-3-ES, p. v (2023-2026 forecasts).

(b) PG&E-64, p. JCE 3-146 (TURN's recommendation).

TURN's recommended \$16.3 million reduction (see table above) to the MWC 29 forecast is based on its disagreement with the modelling conducted by PG&E's third-party consultant, RCG claiming that even with an increase in real estate demand, supply is of concern and that therefore the RCG model forecast is too high.¹⁴⁷¹ TURN offers its own adjustments and calculations to the RCG permitting forecast, that result in a difference in forecast residential gas

¹⁴⁷¹ TURN-08, p. 14, lines 1-6..

connections of 34,154 over the rate case period, with PG&E forecasting 138,298 new connections and TURN forecasting 104,144 connections.¹⁴⁷²

TURN also recommends further reductions to MWC 29 if the Commission modifies or eliminates gas line extension subsidies in rulemaking R.19-01-011 Phase III.¹⁴⁷³ TURN states that if the line extension subsidies are eliminated as of July 1, 2023, then “PG&E’s test year forecasts should be reduced by 50%” over the other reductions already proposed by TURN.¹⁴⁷⁴ Additionally, TURN recommends eliminating all funding for attrition years beyond 2023.

Subsequently, on September 15, 2022 the Commission issued D. 22-09-026 which eliminated the gas line extension allowances as of July 1, 2023 (the Gas Allowance Decision).¹⁴⁷⁵ The Commission also approved an application process after July 1, 2023 for specific, unique non-residential projects where a gas line subsidy may still be warranted.¹⁴⁷⁶ In Section 3.13.2.1 below, PG&E discusses the impact of the Gas Allowance Decision and proposes a revised forecast for MWC 29 that should be subject to a one way balancing account. In Section 3.13.2.2 below, PG&E requests clarification regarding funding for specific unique non-residential projects approved pursuant to the post-July 2023 special application process. In Section 3.13.2.3 below, PG&E addresses TURN’s proposed changes to RCG’s residential permitting methodology.

¹⁴⁷² PG&E-16-E, p. 14-14, lines 21-25.

¹⁴⁷³ TURN-08, p. 21, line 19 to p. 22, line 1.

¹⁴⁷⁴ TURN-08, p. 21, lines 11-14.

¹⁴⁷⁵ *Order Instituting Rulemaking Regarding Building Decarbonization*, R.19-01-011 (Jan. 31, 2019). Phase III Decision Eliminating Gas Line Extension Allowances, Ten Year Refundable Payment Option, And Fifty Percent Discount Payment Option Under Gas Line Extension Rules. D.22-09-026.

¹⁴⁷⁶ *Id.*, p. 80, COL 2 and 3.

3.13.2.1 A Revised Forecast Should Be Adopted Given the Commission’s Gas Allowance Decision

The Gas Allowance Decision “adopts Energy Division’s staff proposal to eliminate gas line extension allowances . . . under the current gas line extension rules. The elimination is for all customers in all customer classes effective July 1, 2023. . . . Applications submitted before July 1, 2023 will not be affected by this decision.”¹⁴⁷⁷

In light of this decision, PG&E’s forecast for MWC 29 should be reduced since PG&E’s original forecast assumed that gas line extension allowances would continue to be in effect for the entire GRC forecast period. However, despite the elimination of allowances for applications received after July 1, 2023, a significant portion of the forecast will still be needed for: (1) ongoing allowances and refunds related to currently eligible projects that are already completed or will be completed in the future; (2) allowances and future refunds for projects constructed under new applications submitted to PG&E before July 1, 2023; and (3) other miscellaneous costs required for new gas connections, including costs that are not covered by the applicant, i.e., estimate vs. actual cost variations due to timing, and certain meter material costs.¹⁴⁷⁸

As noted above, projects with applications submitted before July 1, 2023 are still entitled to a gas line extension allowances. These “grandfathered” projects may still be under construction for several years into the rate case period. Contracts may be eligible for refunds that are generated by connections for up to 10 years after the date the associated project went into service.¹⁴⁷⁹ This could include connections within the scope of the original project as well as in-series connections downstream of the original project.

¹⁴⁷⁷ D. 22-09-026, p. 2.

¹⁴⁷⁸ PG&E-16-E, p. 14-17, lines 1-20.

¹⁴⁷⁹ D. 22-09-026, p. 10-11, “Refundable costs in excess of allowances, if any, are returned to an applicant via either: (1) refunds over 10 years; or (2) a one-time 50 percent discount at the option of the applicant.”

To take into account the Gas Allowance Decision, and to ensure adequate funding for this program in the 2023 GRC cycle, PG&E proposes a reduced 2023 forecast of \$85.4 million, compared to PG&E’s original 2023 forecast of \$126 million. This revised forecast would be adjusted for 2024, 2025, and 2026 under the Commission’s adopted Post Test Year Ratemaking methodology for capital forecasts. PG&E’s revised forecast is constructed as follows.

First, the non-allowance-based activities of this program still need to be funded. These costs are not affected by the decision. PG&E forecasts \$20 million in 2023 for these activities that include costs that are not covered by the applicant, i.e., estimate vs. actual cost variations due to timing, and certain meter material costs.¹⁴⁸⁰ These non-allowance related costs are the difference between PG&E’s 2023 original MWC 29 forecast of \$126 million¹⁴⁸¹ and the \$106 million forecast of total allowance subsidies for 2023,¹⁴⁸² i.e., \$20 million.

Second, PG&E estimates that for both existing applications that are in planning and construction, and for new applications submitted before July 1, 2023, it will still be required to pay the full level of forecasted allowance subsidies in both 2023 and 2024, and a reduced level in 2025. Allowances in 2023 will be paid at the forecast rate for projects that are currently in planning and construction and will be implemented in the year 2023. The decision will have no impact on the need to pay for these “in flight” projects. With respect to 2024 and 2025, the decision allows projects to qualify for allowances if applications are submitted by July 1, 2023. Given that allowances will be discontinued after July 1, it is reasonable to expect that a high volume of applications will be submitted between now and July 2023 that could match a full year’s worth of applications that PG&E might have received absent the decision. Due to the lag in contracting and construction that follows submission of an allowance application, the

1480 PG&E-16-E, p. 14-17, lines 1-20.

1481 See Table 3-63 above.

1482 D. 22-09-026, p. 15, Table 2, Row 1. The table shows forecast total customer subsidies for PG&E of \$106 million in 2023; \$105 million on 2024; \$101 million in 2025; and \$97 million in 2026.

allowances for these new applications will be paid in 2024 and 2025 as shown in Table 3-64 below that illustrates the potential timeline for an application received by the July 1, 2023 deadline for new applications.¹⁴⁸³

**TABLE 3-74
POTENTIAL APPLICATION TIMELINE**

	Application Deadline	Design & Estimate	Contract Signing	Construction Start	Construction End
Current Durations		6 months	3 months	3 months	12 months
Dates	July 1, 2023	December 31, 2023	March 31, 2024	June 30, 2024	June 30, 2025

Accordingly, PG&E requests full funding for the 2023 and 2024 forecast subsidies of \$106 million and \$105 million respectively with a 50% reduction in 2025 of \$50.5 million (i.e., half of \$101 million).¹⁴⁸⁴ The allowance subsidies for these three years total \$261.5 million that should be apportioned equally across the 2023 GRC rate period, i.e., \$65.4 million in 2023.

Based on the foregoing, PG&E requests a revised 2023 forecast for MWC 29 of \$85.4 million, i.e., \$20 million for on-going non-allowance related costs, and \$65.4 million for allowances on in-flight projects and new project applications. To protect ratepayers against the uncertainty of this forecast, PG&E also proposes that the revenues associated with this forecast be trued up at the end of the rate case cycle by means of a one-way balancing account.

For the reasons discussed above, TURN's recommendation that 50 percent of the test year costs should be eliminated mid-year 2023 and that funding should go to zero in subsequent years,¹⁴⁸⁵ is therefore overly simplistic in that it ignores continued costs related to this program that will continue after the Gas Allowance Decision. Instead, the Commission should adopt PG&E's revised 2023 forecast for MWC 29 of \$85.4 million

1483 New Business projects, similar to growth-driven pipeline capacity projects, can take several years to design, permit, and construct. PG&E-16-E, p. 11-36, lines 20-23.

1484 D. 22-09-026, p. 15, Table 2, Row 1.

1485 TURN-08, p. 21, lines 11-14.

3.13.2.2 The Commission Should Clarify the Cost Recovery Process for Non-Residential Projects Approved After July 1, 2023

The decision also “approves the Joint Parties and TURN’s proposal for an application process, with modifications, for those specific, unique non-residential projects where a gas line subsidy may still be warranted. For these projects, the gas IOUs shall evaluate the project based on the criteria established in this decision and file an application with the Commission for approval of a gas line subsidy on behalf of the project applicant(s).”¹⁴⁸⁶ The application should be filed each year by July 1.¹⁴⁸⁷ Since there is currently no way of forecasting these projects, PG&E has not included any costs for allowances related to such future projects in its revised forecast for MWC 29.

PG&E requests that the Commission clarify the cost recovery process for projects that may be approved pursuant to the annual July 1 application process. The Commission should either confirm that cost recovery will be authorized and addressed in the applications, or the Commission should authorize PG&E to establish a memorandum account to recover the allowance/subsidy costs for approved projects.

3.13.2.3 TURN’s approach to Determining the Number of Residential Permits is Flawed

TURN’s recommended \$16.3 million reduction (see table above) to the MWC 29 forecast for MWC 29 is solely determined by different assumptions regarding the number of residential permits for single family connections in the model.¹⁴⁸⁸ Those adjustments result in a difference in forecast residential gas connections of 34,154 over the rate case period, with PG&E forecasting 138,298 new connections and TURN forecasting 104,144 connections.¹⁴⁸⁹ TURN’s

¹⁴⁸⁶ D.22-09-026, p. 56.

¹⁴⁸⁷ *Id.*, p. 80, COL 3.

¹⁴⁸⁸ PG&E-16-E, p. 14-15, lines 5-7.

¹⁴⁸⁹ PG&E-16-E, p. 14-14, lines 3-25.

proposed adjustments to PG&E's residential permit forecast are summarized in PG&E's rebuttal testimony.¹⁴⁹⁰

PG&E does not agree with TURN's approach to determining the appropriate number of residential permits. PG&E continues to support RCG's model in its entirety, including the model used to generate the forecasted number of residential permits. PG&E has used RCG's model to forecast capital expenditures associated with the GD New Business program prior to the 2023 GRC. PG&E used this model in the 2017 and 2020 GRCs in which the Commission adopted PG&E's forecast in its entirety.¹⁴⁹¹ PG&E's response to TURN's permit modelling approach is discussed in Section 4.18.3 of this brief.

TURN's recommended new business interconnection forecast is insufficient for PG&E to complete the work required in the GD New Business Program (MWC 29) and the Commission should adopt PG&E's revised forecast for MWC 29.¹⁴⁹²

3.13.3 Gas Transmission (GT) New Business (NB) Program – Capital (MAT 26A)

The GT NB Capital Program consists of projects that require either significant pressure or new load along with other major projects.¹⁴⁹³ PG&E's forecast for the GT NB program is \$7.9 million in the 2023 test year. A five-year historical average (2015 through 2019) of escalated capital expenditures for this program was used to determine the forecast for the rate case period. Additionally, \$5.8 million has been added to the forecast for anticipated major conversion projects.¹⁴⁹⁴ The adder was based specifically on PG&E's Large Gas Solutions program that presents solutions to large customers to switch from alternative higher GHG fuels

¹⁴⁹⁰ PG&E-16-E, p. 14-13, lines 22 to p. 14-14, line 18.

¹⁴⁹¹ PG&E-16-E, p. 14-15, lines 14-18.

¹⁴⁹² PG&E-16-E, p. 14-15, lines 21-23.

¹⁴⁹³ Exhibit 3, p. 14-23, line 4 to p. 14-25, line 24.

¹⁴⁹⁴ PG&E-3-ES, WP 14-19, Workpaper Table 14-19; PG&E-16-E, p. 4-18, lines 3-13.

to natural gas, fueling back up generation with natural gas versus diesel, and converting heavy duty fleets to CNG and constructing CNG stations.¹⁴⁹⁵

Cal Advocates reviewed PG&E’s submitted documentation regarding planned WRO projects and does not oppose MWC 26.¹⁴⁹⁶ TURN also addressed the program and proposes:

TABLE 3-75
GAS TRANSMISSION NEW BUSINESS PROGRAM (MAT 26A): PG&E’S CAPITAL FORECAST AND PARTIES RECOMMENDED REDUCTIONS (\$000s)^(a)

Party	2020 Rec.	2021	2022	2023	2024	2025	2026
PG&E	\$13,614	\$13,943	\$2,736	\$7,923	\$8,127	\$8,343	\$8,567
TURN				\$(5,774)			
(a) PG&E-16-E, p. 14-25, Table 14-11, line 1 (2020-2022 recorded and forecast costs); PG&E-3-ES, p. v (2023-2026 forecasts); PG&E-64, p. JCE 3-159 (TURN’s recommendation).							

TURN recommends a reduction of \$5.8 million to PG&E’s forecast on the grounds “that PG&E’s proposed ‘adder’ for additional costs in MWC 26 during the rate case period be denied as speculative and unsupported.”¹⁴⁹⁷ TURN bases its recommendation on a lack of justification for the proposed Large Gas Solutions program expenditures. TURN states that PG&E only provides “a single workpaper page ... with a very broad description of the company’s intentions.”¹⁴⁹⁸ TURN also indicates that PG&E has not provided an “explanation for why the addition of new gas customers switching from dirtier fuels is not already reflected in its historical average for new transmission-level customer connection costs.”¹⁴⁹⁹

TURN’s arguments are unfounded. PG&E has provided forecasts¹⁵⁰⁰ and examples of the types of new conversion projects included in the Large Gas Solutions program. These

¹⁴⁹⁵ PG&E-03, WP-14-25, Large Gas Solutions Project Summary.

¹⁴⁹⁶ CALPA-03, p. 21, lines 10-12.

¹⁴⁹⁷ TURN-07, p. 45, lines 12-14.

¹⁴⁹⁸ TURN-07, p.45, lines 3-5.

¹⁴⁹⁹ TURN-07, p.45, lines 10-12.

¹⁵⁰⁰ PG&E-03, WP 14-25.

include Cement, Chemical, and Processing Plants, CNG Stations, and Agricultural Farms. Projections were developed using historical project costs and allowances for similar type projects. Some of these new projects also include back up generation for data centers.¹⁵⁰¹

The Large Gas Solutions Program creates a higher level of New Business activity than in past rate case periods. In the past, PG&E's GT New Business service projects would occur only as customers requested them. Today PG&E is proactively identifying opportunities that align with California's climate goals and is reaching out to customers utilizing fuels such as coal, propane, and diesel to convert them to natural gas. PG&E provides customers initial feasibility studies to determine if the project is viable along with analyzing their GHG savings. Given that this new program was only initiated in 2020, PG&E's historic average costs do not reflect the costs of projects generated by the new program as TURN claims. Currently there are more than 20 of these types of new projects identified for execution in the rate case period.¹⁵⁰²

The level of funding recommended by TURN is not enough for PG&E to complete the expected GT NB Capital projects each year based on historical average costs and additional large project forecasts. Not completing these projects will have a negative impact on California's climate goals.¹⁵⁰³

3.13.4 Gas Transmission Work at the Request of Others Program – Capital (MAT 83A)

The GT WRO Capital Program covers transmission pipeline or related facility removals and relocations performed by PG&E at the request of third parties. These projects are typically requested by governmental agencies, such as Cal Trans, cities, counties, regional transportation agencies, and private developers. GT WRO projects are primarily driven by public improvement work, under which PG&E's obligation to relocate its facilities is subject to the terms of a

¹⁵⁰¹ PG&E-16-E, p. 14-19, lines 5-11.

¹⁵⁰² PG&E-16-E, p. 14-19, lines 12-23.

¹⁵⁰³ PG&E-16-E, p. 14-19, lines 26-30.

franchise agreement, master agreement, or eminent domain.¹⁵⁰⁴ PG&E’s original forecast for the GT WRO Capital Program was \$20.9 million in the 2023 test year. A five-year historical average (2015 through 2019) of actual net capital expenditures for this program was used to determine the forecast for the rate case period.¹⁵⁰⁵ Based on information available at the time, a cost adder of \$5.5 million for the Department of Water Resources Delta Conveyance Project (DCP) was also included in the forecast.¹⁵⁰⁶ Following adjustment for PG&E’s concession to TURN’s recommended removal of \$5.5 million from the 2023 forecast for MAT 83A, the adjusted forecast that PG&E is seeking is \$16.0 million.¹⁵⁰⁷

TURN proposes removing the \$5.48 million adder for the DCP from PG&E’s 2023 forecast for GT WRO Capital (MWC 83). In addition, TURN recommends removing estimated expenditures for this project in 2021 and 2022.¹⁵⁰⁸ TURN’s recommendation is based on their understanding of the DCP’s current schedule stating “[i]t is extremely unlikely that PG&E will be required to perform this relocation work during this rate case period.”¹⁵⁰⁹

PG&E agrees with TURN’s recommendations for reducing PG&E’s forecasts by removing the DCP adder. Although it was anticipated the DCP project would impact the 2023 GRC rate case period at the time of the filing, based on current projections, PG&E agrees that the DCP is not progressing at a pace that will require significant capital work by PG&E in the rate case period. TURN’s recommended funding level after adjusting to remove the DCP adder, is sufficient. By removing the adder for the DCP, TURN’s forecast matches PG&E’s request.

¹⁵⁰⁴ PG&E-03, p. 14-26, line 1 to p. 14-28, line 4.

¹⁵⁰⁵ PG&E-03, WP 14-20, Workpaper Table 14-20.

¹⁵⁰⁶ PG&E-16-E, p. 14-20, lines 16-23.

¹⁵⁰⁷ PG&E-3-ES, p. v.

¹⁵⁰⁸ TURN-07, p. 44, lines 3-8.

¹⁵⁰⁹ TURN-07, p. 43, lines 13-14.

Accordingly, the Commission should approve a 2023 adjusted forecast for MAT 83A of \$16.0 million.¹⁵¹⁰

3.14 Ratemaking

In this section PG&E addresses the cost recovery accounts related to Exhibit PG&E-03, Gas Operations. Below PG&E discusses specific accounts where PG&E's recommendations were disputed. Section 3.14.3.4 lists the accounts where PG&E's recommendations were not disputed. Section 3.14.3.5 identifies two new cost recovery accounts proposed in this brief that are associated with MWC 29.

3.14.1 Gas Storage Balancing Account (GSBA)

The GSBA is addressed in Section 3.6.10 above.

3.14.2 Transmission Integrity Management Plan Balancing Account (TIMPBA)

The TIMPBA and the TIMP Memorandum Account (TIMPMA) are addressed in Section 3.4.7 above.

3.14.3 Other Balancing and Memorandum Accounts

3.14.3.1 In-Line Inspection Memorandum Account (ILIMA) and Internal Corrosion Direct Assessment Memorandum Account (ICDAMA)

The ILIMA is addressed in Section 3.4.8 above and the ICDAMA is addressed in Section 3.4.9 above.

3.14.3.2 The Internal Corrosion Balancing Account (ICBA)

The 2019 GT&S Final Decision established the one-way Internal Corrosion Balancing Account (ICBA) for capital internal corrosion expenditures recorded in MAT 3K1.¹⁵¹¹

PG&E recommends that the Commission discontinue the ICBA in 2023.¹⁵¹²
Cal Advocates disagrees with PG&E's recommendation and recommends the Commission

¹⁵¹⁰ PG&E-3-ES, p. v.

¹⁵¹¹ D.19-09-025, p. 204.

¹⁵¹² PG&E-03, p. 9-64, lines 15-27.

continue with the ICBA. Cal Advocates asserts that PG&E has performed below the level adopted by the Commission for the years 2019-November 2021. Cal Advocates further asserts it “is not convinced that PG&E will replace or remove pipelines at the level propose[d] for the next GRC cycle.”¹⁵¹³

The ICBA should be discontinued as recommended by PG&E. The Commission’s stated rationale for the ICBA was that PG&E’s 2019 GT&S rate case application did not explain with adequate detail its methodology for calculating its capital forecast.¹⁵¹⁴ PG&E’s 2023-2026 capital cost forecast for capital internal corrosion is provided in Exhibit PG&E-03, WP 9-90, and is based on actual pipe replacement data that is utilized across multiple chapters of this application. The complete details of the pipe replacement cost curves are provided in Exhibit PG&E-03, WP 5-109. PG&E has therefore addressed the Commission’s stated rationale for the ICBA and requests that the ICBA be discontinued at the end of the current rate case period.

PG&E acknowledges that recorded expenditures for Capital Internal Corrosion Mitigation, MAT 3K1, for the period 2019-November 2021 were below adopted; however, PG&E anticipates exceeding the number of pipeline drip replacements forecast in the 2019 GT&S.¹⁵¹⁵ Cal Advocates’ assertion that PG&E has performed below the level adopted by the Commission for the years 2019-November 2021 is solely based on recorded spend and does not consider the number of pipeline drips that have been removed or replaced.¹⁵¹⁶

3.14.3.3 New Environmental Regulations Balancing Account (NERBA)

In the 2020 GRC settlement, that was adopted by the Commission in D.20-12-005, the parties agreed to the continuation of NERBA in 2020-2022 (Section 4.1.1.1):

¹⁵¹³ CALPA-02, p. 66, lines 20-22.

¹⁵¹⁴ D.19-09-025, p. 329, OP 54.

¹⁵¹⁵ PG&E-03, p. WP 9-108, line 1.

¹⁵¹⁶ PG&E-16-E, p. 9-22, lines 22-29.

This balancing account is used to track the difference between actual and adopted costs related to 26 best-practice activities associated with minimizing methane emissions as adopted by the Commission in the Natural Gas Leak Abatement Order Instituting Rulemaking (R.15-01-008). This account shall be modified and the distribution subaccount will be retained through 2022 for the sole purpose of tracking the costs associated with below ground Grade 3 leak repairs (Best Practice 21).¹⁵¹⁷

PG&E requests continuation of NERBA in the 2023 GRC period to record Below Ground Grade 3 (BG3) leak repairs to ensure that PG&E and ratepayers are protected against the continued uncertainty and potential fluctuation in the number and costs of repairs.¹⁵¹⁸ The level of BG3 repairs that PG&E is required to perform to meet Best Practice (BP) 21 continues to be uncertain. For the period 2023-2026, the required level of BG3 leak repair could be higher or lower than the current forecast of 2,000 repairs per year since the level of repair is revisited every two years in PG&E's biennial Leak Abatement Compliance Plan submitted to the CPUC.¹⁵¹⁹

Cal Advocates recommends that "NERBA...be discontinued at the end of 2022."¹⁵²⁰ Cal Advocates claims that: "[t]he issue of below ground Grade 3 leak repair costs and level of repairs was resolved through Resolution G-3538";¹⁵²¹ "If NERBA is continued...[t]he utility has no incentive to be efficient or cost effective in managing the repair of below ground Grade 3 leaks."¹⁵²²; and, "[T]here is currently no pending proceeding before the Commission that warrants the tracking of Grade 3 below ground leak repairs and associated costs."¹⁵²³ Cal Advocates' arguments lack merit as shown below.

¹⁵¹⁷ 2020 GRC Settlement Agreement Section 4.1.1.1 approved in D.20-12-005, p. 32.

¹⁵¹⁸ PG&E-03, p. 10-52, lines 3-20.

¹⁵¹⁹ PG&E-16-E, p. 10-24, lines 14-22.

¹⁵²⁰ CALPA-02, p. 88, line 8.

¹⁵²¹ CALPA-02, p. 88, lines 19-20.

¹⁵²² CALPA-02, p. 89, lines 3-6.

¹⁵²³ CALPA-02, p. 89, lines 9-10.

First, contrary to Cal Advocates’ claim, Resolution G-3538 did not resolve the level of BG3 repairs that PG&E must perform.¹⁵²⁴ In fact, Resolution G-3538 created significant uncertainty as to what level of BG3 repairs the Commission would deem to be cost effective. The Commission found “PG&E’s proposal to reduce its leak backlog of Grade 3 underground leaks is excessively costly relative to the expected emission reduction”¹⁵²⁵ and indicated that the BG3 leak repair program would be reevaluated in 2020 after the Commission had a chance to review cost and emissions data from repairs completed in 2018 and 2019.¹⁵²⁶ Following this direction, PG&E submitted its 2020-2021 Leak Abatement compliance plan in March 2020¹⁵²⁷ providing methane reduction cost data on BG3 leak repairs as requested and proposed to repair approximately 2,000 BG3 leaks per year consistent with its 2020 GRC forecast.¹⁵²⁸ On December 18, 2020, the Commission’s SPD approved PG&E’s 2020-2021 compliance plan.¹⁵²⁹

Second, the biennial leak abatement compliance plan process means that the uncertainty of the appropriate level of BG3 repairs is likely to continue. There are three compliance plans that will be approved or submitted before 2026 (i.e., the plans for 2022-2023; 2024-2025; and 2026-2027). Based on any one of these plans, staff could decide that in light of changing cost

¹⁵²⁴ Res. G-3538, Forecast Requests for Utility Natural Gas Leak Abatement Program Memorandum and Balancing Accounts (Oct. 11, 2018).

¹⁵²⁵ Res.G-3538 (Oct. 11, 2018) p. 15, Finding 12.

¹⁵²⁶ Res. G-3538 (Oct. 11, 2018), Attachment A, p. 25, the SED Evaluation Report for Pacific Gas and Electric Company 2018 Leak Abatement Compliance Plan states: “The remaining backlog of Grade 3 leaks should be addressed in the 2020 Compliance Plan based on actual cost-effectiveness experience learned from this initial effort, combined with information gained from the various research projects.”

¹⁵²⁷ R.15-01-008, PG&E’s Gas Safety Plan (Mar. 16, 2020), Attachment 1, 2020 Leak Abatement Compliance Plan.

¹⁵²⁸ R.15-01-008, PG&E’s Gas Safety Plan (Mar. 16, 2020), Attachment 1, 2020 Leak Abatement Compliance Plan, p. Atch1-38.

¹⁵²⁹ R.15-01-008, Letter from Danjel Bout, Director, Safety Policy Division, to Christine Cowser, PG&E VP, Gas Asset Management and System Operations confirming SPD’s “Risk Assessment and Safety Analytics Section, Staff Evaluation, PG&E 2020 Natural Gas Leak Abatement Compliance Plan”, attached to the letter.

effectiveness of BG3 repairs, or the relative cost effectiveness of BG3 repairs compared to other Best Practice methane mitigation measures, a different level of BG3 repairs is appropriate in a future year.¹⁵³⁰ On March 15, 2022 PG&E submitted its 2022-2023 plan to the SPD¹⁵³¹ requesting the option to implement a more cost-effective BG3 leak repair approach in 2023 that could result in a greater amount of methane reduction. Specifically, PG&E proposed the option to perform more “Super Emitter” leak repairs,¹⁵³² which have greater methane reduction, and as a result be permitted to reduce the number of BG3 leaks repairs, which have lower methane reduction, from 2,000 to 1,000 leaks per year.¹⁵³³ On September 12, 2022, PG&E’s proposal was approved by the SPD.¹⁵³⁴ If PG&E opts to implement this approach in 2023, NERBA will return to ratepayers any revenues associated with the difference between performing 2,000 BG3 leaks as requested in this GRC, and the new rate of 1,000 BG3 lead repairs, provided that the balancing account is continued.¹⁵³⁵

Finally, there is no merit to Cal Advocates’ claim that continuing NERBA will impact PG&E’s efficiency and cost effectiveness of doing BG3 leak repairs. PG&E’s execution of leak

¹⁵³⁰ PG&E-16-E, p. 10-26, lines 12-24.

¹⁵³¹ R.11-02-019, PG&E’s 2022 Gas Safety Plan, Attachment 2, 2022 Leak Abatement Compliance Plan (Mar. 15, 2022), pp. 39-40.

¹⁵³² PG&E’s Super Emitter survey program is designed to detect and prioritize large leaks for repair. The Super Emitter survey is performed in addition to existing compliance surveys and prioritizes repairs for leaks with a flow rate of greater than 10 standard cubic feet per hour (scfh). See PG&E-03, p. 10-12, line 15 to p. 10-13, line 20.

¹⁵³³ PG&E-16-E, p. 10-27, lines 3-13.

¹⁵³⁴ Letter from Danjel Bout, Director, Safety Policy Division to Christine Cowser Sr. VP, Gas Engineering, PG&E, September 12, 2022. The letter states: “In recognition of the expected cost-effectiveness improvement, Staff approve the proposed option to reduce the threshold for the Super Emitter program to 7 scfh, in lieu of approximately half of the forecasted 2000 belowground Grade 3 leak repairs.”

¹⁵³⁵ PG&E-16-E, p. 10-27, lines 13-18.

repair is uniform for all leak repairs and does not differentiate between NERBA eligible repairs and other repairs.¹⁵³⁶

For all these reasons and given the uncertainty due to the biennial reevaluation of BG3 leak repair cost effectiveness, a continuation of NERBA is critical to protect ratepayers and PG&E from fluctuations in the SPD-approved level of cost effective BG3 leak repairs.

3.14.3.4 Undisputed Balancing and Memorandum Accounts

Below is a list of Balancing and Memorandum Accounts that were not disputed that PG&E is proposing closing. Additional details regarding these balancing and memorandum accounts and citations to PG&E's testimony is provided in Appendix B.

- Engineering Critical Assessment Balancing Account (ECABA)
- Critical Documents Program Memorandum Account (CDPMA)
- Dairy Biomethane Solicitation Memorandum Account (DBSMA)
- Below Ground Storage Decommissioning Balancing Account (BGSDBA)
- Cushion Gas Memorandum Account (CGMA)
- Measurement and Control Station Rebuilds Balancing Account (MCSRBA)
- Hydrostatic Testing Balancing Account (HTBA)
- Atmospheric Corrosion Balancing Account (ACBA)
- Physical Security Balancing Account (PSBA)
- Measurement and Control Over-Pressure Protection Memorandum Account (MCOPPMA)
- Root Cause Analysis Memorandum Account (RCAMA)
- Routine Compression and Processing Memorandum Account (RCPMA)
- Locate and Mark Memorandum Account (LMMA)
- Alternating Current Interference Balancing Account (ACIBA)

¹⁵³⁶ PG&E-16-E, p. 10-28, lines 8-10.

- Casings Balancing Account (CBA)

Below is a list of Balancing and Memorandum Accounts that were not disputed that PG&E proposes continuing with no modifications. Additional details regarding these balancing and memorandum accounts and citations to PG&E's testimony is provided in Appendix B.

- Gas Statutes, Regulations, and Rules Memorandum Account (GSRRMA)
- Line 407 Memorandum Account (L407MA)

3.14.3.5 New Accounts Related To MWC 29

In Section 3.13.2, Gas Distribution Capital New Business Program – Capital (MWC 29), PG&E identifies two new accounts that should be established in connection with this work. Specifically, in light of CPUC Decision 22-09-026 issued September 15, 2022 which eliminated the gas line extension allowances as of July 1, 2023, PG&E proposes a revised forecast for MWC 29 that should be subject to a one way balancing account (Section 3.13.2.1 of this brief). Further, PG&E requests clarification regarding funding for specific unique non-residential projects approved pursuant to the post-July 2023 special application process approved in D.22-09-026, and proposes a memorandum account to track costs associated with these projects (Section 3.13.2.2).

4. ELECTRIC DISTRIBUTION (EXHIBIT PG&E-04)

4.1 PG&E Forecast and Overview

Electric Distribution (ED) is focused on achieving its core mission to deliver affordable and clean energy safely and reliably to our customers. To that end, ED's expense and capital forecasts presented in this GRC represent a risk-informed portfolio that puts safety first while maintaining a reliable electric system and positioning the utility to meet future challenges, including those presented by climate change.

As reflected in these forecasts, ED is primarily focused on achieving the following key objectives: (1) addressing system needs to maintain a resilient and reliable electrical system as demand for electricity accelerates; (2) mitigating wildfire risks caused by climate-change and drought conditions; (3) supporting California's GHG emissions reductions goals; (4) improving public and workforce safety; and (5) continued focus on operational excellence.¹⁵³⁷ ED's forecast activities in this GRC each support one or more of these important objectives in some significant way. For example, the forecasts for PG&E's risk management, undergrounding, system hardening programs, vegetation management and other wildfire mitigations are vitally necessary to fund PG&E's efforts to effectively mitigate wildfire risks and protect public safety. PG&E's inspection, maintenance, and asset management forecasts are foundational to ensuring public and workforce safety and maintaining a safe and reliable electric system. Forecasts for programs associated with supporting distributed energy resources support California's emissions reductions goals.

And all of these activities are fundamental to PG&E's efforts to achieve operational excellence.

¹⁵³⁷ PG&E-04, p. 1-6, line 11 to p. 1-12, line 34.

PG&E's TY 2023 expense forecast for ED presented in the JCE, (Exhibit PG&E-64) is \$2,210¹⁵³⁸ million, of which \$782 million, 35 percent, is uncontested.¹⁵³⁹ PG&E's expense forecast presented in the JCE including a change in escalation percentage (the September 22 updated escalation) is \$2,597 million.¹⁵⁴⁰

PG&E's capital expenditures forecast presented in its the JCE is \$3,454 million in 2021, \$4,031 million in 2022, and \$4,518 million in 2023,¹⁵⁴¹ \$5,645 million in 2024, \$6,150 million in 2025 and \$6,615 million in 2026.¹⁵⁴² Approximately \$627 million of PG&E's 2023 capital forecast, 14 percent, is uncontested.¹⁵⁴³ PG&E's capital expenditures forecast presented in the JCE including a change in escalation percentage, is \$3,571 million in 2021, \$4,406 million in 2022, \$5,118 million in 2023, \$6,605 million in 2024, \$7,211 million in 2025 and \$7,584 million in 2026.¹⁵⁴⁴

PG&E submitted ample evidence demonstrating the reasonableness of these forecasts. In particular, PG&E's ED testimony (Exhibits PG&E-04 and PG&E-17) explains in detail the scope of ED activities planned by PG&E and how those activities are vital to maintaining a safe and reliable electric distribution system and addressing wildfire risks effectively.

¹⁵³⁸ PG&E-64, Column "PG&E (without Sept 6 Non-Labor Escalation Adjustment) includes all post-February 28, 2022 errata and concessions. *See* PG&E-64, p. 3-2, Table 3A-1 and all PG&E-04.

¹⁵³⁹ *See* Appendix A, p. A-12, line 225. Calculated as: \$782 million / \$2,210 million = 35%.

¹⁵⁴⁰ PG&E-64, p. 3-2, Table 3A-1, line "Total Exhibit (PG&E-04)," Column "PG&E (with Sept. 6 Non-Labor Escalation Adjustment)."

¹⁵⁴¹ PG&E-64, p. 3-15, Table 3B-3, line "Total Exhibit (PG&E-4)" (2021); p. 3-11, Table 3B-2, line "Total Exhibit (PG&E-4)" (2022); p. 3-7, Table 3B-1, line "Total Exhibit (PG&E-4)" (2023) Column "PG&E (without Sept 6 Capital Escalation Adjustment).

¹⁵⁴² PG&E-17, p. 2-8, Table 2-5, line 22 (2024); p. 2-9, Table 2-6, line 22 (2025); p. 2-10, Table 2-7, line 22 (2026).

¹⁵⁴³ *See* Appendix A, p. A-21, line 114. Calculated as: \$627 million / \$4,518 = 14%.

¹⁵⁴⁴ PG&E-64, p. 3-15, Table 3B-3, line "Total Exhibit (PG&E-04)" (2021); p. 3-11, Table 3B-2, line "Total Exhibit (PG&E-04)" (2022); p. 3-7, Table 3B-1, line "Total Exhibit (PG&E-04)" (2023), Column "PG&E (with Sept 6 Capital Escalation Adjustment). The forecasts for 2024-2026 are not included in the JCE but are provided here for reference.

Some of our expense and capital forecasts for ED are unopposed. Other forecasts are opposed by a single party. Perhaps the most controversial ED expense and capital forecasts are the MWCs and MATs related to undergrounding and wildfire mitigation work. Cal Advocates, TURN, and AARP recommend large reductions to numerous components of PG&E's forecasts for other wildfire mitigation work, inspection and maintenance activities, asset management programs, system automation and protection activities, capacity work, and data management, among others. Intervenor's arguments raise cost-based objections that challenge the scope, pace, and timing of PG&E's work plans, with customer affordability as a prominent theme.

As addressed above in Section 1.3, PG&E understands customer-affordability concerns. But it is also important for PG&E to re-invest in electrical infrastructure to build and maintain a resilient and reliable electrical system and mitigate wildfire risks, which in itself promotes customer affordability as PG&E is able to reduce certain expenses over time by deploying more effective permanent solutions. The Commission should be cognizant of these needs when reviewing PG&E's forecasts and considering intervenor's counterproposals. The risk of wildfire is urgent; PG&E must be adequately funded to address these infrastructure needs and climate-driven wildfire risks in this proceeding. PG&E respectfully urges the Commission to approve PG&E's ED expense and capital forecasts so that PG&E can move forward with the critical safety and reliability work described in this Section 4 of the opening brief.

4.2 Electric Distribution Risk Management

PG&E is committed to the safety of our customers and communities, including reducing wildfire risk and other risks from electric distribution equipment and operations. To mitigate these risks, PG&E uses risk-informed decision-making to identify and implement the programs that target the key risk drivers. Our risk models and tools quantify and analyze the risks posed by our equipment and operations and help prioritize the different programs for mitigating these risks. In addition, PG&E's risk management organization conducts risk analysis activities; maps risk drivers, controls and consequences that impact risk; identifies and develops mitigations to

promote risk reduction; calculates RSEs; and establishes key performance indicators and metrics to monitor risk mitigation performance. In the subsections below, PG&E: (1) provides an overview of PG&E's wildfire risk modeling; (2) addresses the effectiveness of PG&E's system hardening program to mitigate wildfire risks; and (3) addresses other electric distribution risk related issues raised by parties.

4.2.1 PG&E's Wildfire Distribution Risk Model

PG&E's Wildfire Distribution Risk Model (WDRM) is at the center of the Electric Operations line of business's risk planning efforts for Distribution voltage overhead facilities. The WDRM is a planning model that calculates wildfire risk probabilities of ignition and consequence scores for the overhead distribution system in HFTD areas at the circuit segment level. The WDRM informs the targeting of mitigation programs and helps prioritize the highest wildfire risk miles on PG&E's distribution system in the HFTD.¹⁵⁴⁵ There have been several iterations of the WDRM: PG&E developed the original WDRM (version 1) in 2019 for mitigation planning in 2019 and 2020; the WDRM version 2 (WDRM v2) was approved in late 2020 and PG&E used this version to inform work planning in 2021 and 2022. In 2022, PG&E developed the WDRM version 3 (WDRM v3) to inform future years beginning 2023.¹⁵⁴⁶ WDRM v3 incorporates several improvements over WDRM v2, which are described in PG&E's rebuttal testimony.¹⁵⁴⁷

¹⁵⁴⁵ PG&E-17, p. 3-2, lines 11-13.

¹⁵⁴⁶ PG&E-17, p. 3-2, line 15 to p. 3-3, line 6. MGRA recommends that, in a separate track in this proceeding or in a subsequent proceeding, PG&E provide additional information concerning the technical details of its WDRM v3 model and demonstrate how its results differ from the WDRM v2 model used for the GRC. MGRA-01, p. 89, lines 20-25. MGRA's proposal is unnecessary given that parties have had an opportunity to conduct detailed discovery regarding the outputs of both models. However, PG&E is open to discussing with the Commission and parties identifying a venue to discuss technical details of the WDRM v3 and explain how its results may differ from the WDRM v2 model.

¹⁵⁴⁷ PG&E-17, p. 3-4, line 7 to p. 3-5, line 18.

PG&E is using WDRM v3 to select the target miles forecast in its system hardening undergrounding program. PG&E has recently developed and implemented a framework, based on the WDRM v3, for risk ranking the circuit segments in the HFTD by considering the feasibility of execution. This repeatable framework, which aligns with PG&E's Integrated Grid Planning process and focuses on wildfire risk and feasibility as decision-making criteria, will inform selection of projects for the undergrounding program. As discussed in the next section, PG&E has already used the framework to identify a first tranche of miles for consideration based on the latest risk and feasibility-modeling information.¹⁵⁴⁸

The decision-making framework ranks circuit segments based on a metric called the Simplified Wildfire Risk Spend Efficiency (Simplified Wildfire RSE) and also known internally as Wildfire Feasibility Efficiency (WFE). The Simplified Wildfire RSE considers three factors – mitigation risk reduction benefits, mitigation cost estimate, and feasibility of underground construction – to inform work prioritization by identifying locations where risk reduction benefits can be achieved most efficiently in terms of cost and time to construct.¹⁵⁴⁹ PG&E has performed an analysis that shows that by ranking circuit segments by Simplified Wildfire RSE rather than by the unadjusted output of the WDRM v3, PG&E will achieve more risk reduction and be able to underground more miles of overhead distribution lines in HFTD areas for the same forecast cost.¹⁵⁵⁰

¹⁵⁴⁸ PG&E-17, p. 3-5, line 22 to p. 3-6, line 2.

¹⁵⁴⁹ PG&E describes the Simplified Wildfire RSE in greater detail in its rebuttal testimony, including an explanation of how it is calculated and how it differs from the S-MAP RSE. PG&E-17, p. 3-6, line 10 to p. 3-7, line 29.

¹⁵⁵⁰ PG&E-17, p. 3-8, line 20 to p. 3-9, line 8.

4.2.2 Effectiveness Of PG&E's System Hardening Programs To Mitigate Wildfire Risk

In this section, PG&E addresses: (1) risk analyses supporting PG&E's undergrounding program; (2) TURN's risk-related comments regarding our undergrounding program; and (3) MGRA's risk-related comments regarding our undergrounding program.

4.2.2.1 Overview Of PG&E's Undergrounding Program Risk Issues

The objective of PG&E's undergrounding program is to permanently reduce risk by undergrounding 10,000 miles of distribution lines in and near HFTD areas. Once completed, 10,000 miles of undergrounding as proposed by PG&E would virtually eliminate wildfire ignition risk in at least 70 percent of HFTD areas. To develop a list of prioritized miles for the program, PG&E started with a 1-N list of circuit segments ranked based on the Simplified Wildfire RSE. This list includes approximately 8,100 overhead miles bundled at the circuit level that the system hardening undergrounding teams are using to develop the 10,000-mile underground plan. PG&E used this list to develop three tranches of miles.¹⁵⁵¹

The first tranche is forecast during this rate case period and the remaining two tranches will be addressed in subsequent rate case periods. The circuit segments included in Tranche 1 provide a risk-based set of locations for further review. Additional items PG&E will consider when developing its prioritized list include reliability risks, fire rebuilds, new business projects, work requested by others, capacity, or other localized customer response needs. All emerging items are reviewed and approved by our WRGSC if locations are being proposed for the workplan outside of the currently approved selection criteria.¹⁵⁵²

During this rate case period, PG&E plans to complete approximately 3,300 system hardening underground miles from 2023 through 2026 at a forecast cost of approximately

¹⁵⁵¹ PG&E-17, p. 3-8, lines 1-6.

¹⁵⁵² PG&E-17, p. 3-8, lines 7-17.

\$9,853 million.¹⁵⁵³ PG&E’s undergrounding proposal represents approximately 10 percent of the overhead miles in HFTD areas and will reduce wildfire HFTD risk by approximately 33 percent.¹⁵⁵⁴ The miles PG&E is planning to underground between 2023 and 2026 have the best combination of risk reduction and feasibility based on the WDRM v3.¹⁵⁵⁵

4.2.2.2 Issues Raised By TURN

TURN asserts that PG&E’s system hardening program relies too heavily on undergrounding, given its cost and the availability of PSPS and EPSS as alternative mitigations for wildfire risk. TURN argues that PG&E provides insufficient support in testimony based on RSE scores and questions whether 10,000 miles, or the approximately 3,300 miles forecast here, correctly balances affordability and safety.¹⁵⁵⁶ As discussed in Section 4.3.1.2, PG&E’s analysis demonstrates that its undergrounding program reasonably balances interests of safety and affordability. TURN recommends less undergrounding and greater deployment of overhead system hardening, specifically 200 miles of undergrounding and 1,800 miles of covered conductor/overhead system hardening over the GRC period (50 miles of undergrounding and 450 miles of overhead system hardening per year).¹⁵⁵⁷ TURN proposes an alternate 10-year hardening program with a total of 500 miles of undergrounding and 4,500 miles of overhead system hardening.¹⁵⁵⁸

1553 PG&E’s GRC forecast is based on completing approximately 3,300 system hardening underground miles from 2023 through 2026 (PG&E-04, p. 4.3-51, Table 4.3-11, sum of lines 5 and 8).

1554 PG&E stated in its rebuttal testimony that the undergrounding approximately 3,300 miles in this GRC period would reduce risk in the HFTD by approximately 36 percent (PG&E-17, p. 3-9, lines 13-17). During evidentiary hearings PG&E’s witness testified that subsequent to filing rebuttal testimony, PG&E revised risk reduction from 36 percent to 33 percent. Tr. Vol. 9, 1676:12-16, PG&E/McGregor.

1555 PG&E-17, p. 3-9, line 11 to p. 3-10, line 3 (including Figure 3-2).

1556 TURN-11, p. 32, lines 9-11.

1557 TURN-11, p. 45, lines 4-6.

1558 TURN-11, p. 27, line 6 to p. 28, line 5, including Figure 10.

TURN's recommendation would result in less risk reduction which would be achieved more slowly. TURN's proposal to increase overhead system hardening would leave greater residual risk remaining on the system because, unlike undergrounding which eliminates virtually all ignition risk where it is implemented, covered conductor used in traditional overhead system hardening is less effective. While TURN characterizes its proposal as penny-wise, it is pound foolish. PG&E analyzed TURN's proposal for the GRC period and determined that it would result in approximately 18 percent risk reduction from 2024 to 2026, just over half the 33 percent risk reduction PG&E expects to obtain over that same period.¹⁵⁵⁹

TURN's proposed rate of system hardening would result in approximately 40 percent risk reduction in HFTD areas, but not until 2032. By contrast, the undergrounding work PG&E has forecast in this GRC would provide approximately 33 percent risk reduction in HFTD areas by 2026 at a cost approximately five percent more than TURN's proposed 10-year program. Because TURN's 10-year proposal includes only 500 miles of undergrounding, thousands of high-risk miles in HFTD areas would have remaining residual risk because overhead system hardening only reduces risk by 62 percent, versus 99 percent for undergrounding.¹⁵⁶⁰ TURN's proposal achieves risk reduction much more slowly than PG&E's during a time of increasing wildfire risk due to climate change. Moreover, PG&E's focus on undergrounding will also reduce reliance on de-energization programs and improve reliability.¹⁵⁶¹ At a time when California communities face increased and heightened threat from wildfire risks throughout most

¹⁵⁵⁹ PG&E-17, p. 3-16, lines 18-22 (noting that 2024-2026 risk reduction of PG&E proposal should be 33 percent, rather than the 36 percent shown in PG&E's rebuttal testimony). PG&E's analysis in this instance included only 2024-2026 because PG&E's 2023 workplan is already in process and was based on an earlier version of the risk model (WDRM v2 for 2023 and WDRM v3 for 2024-2026). PG&E's risk reduction would increase accordingly if 2023 were included in the analysis. For accuracy, PG&E also calculated the risk reduction from TURN's proposal for the entire 2023-2026 period (23 percent). PG&E-17, p. 3-16, fn. 39.

¹⁵⁶⁰ PG&E-17, p. 3-17, lines 13-20; Tr. Vol. 9, 1676:12-16, PG&E/McGregor.

¹⁵⁶¹ PG&E-17, p. 3-18, lines 1-5.

of the year, TURN's proposal to slow the rate of risk reduction by almost 50 percent and unnecessarily extend the program for years threatens the customers and communities that PG&E serves.

TURN also raises issues related to the overhead component of PG&E's System Hardening program. TURN claims that overhead system hardening is a more cost-effective approach to mitigating ignition risk, as indicated by a higher RSE score.¹⁵⁶² TURN claims that, even as calculated by PG&E, the RSE for system hardening overhead (5.9) is higher than the RSE for system hardening underground (5.3).¹⁵⁶³ TURN further claims that PG&E has included unnecessary asset replacements in its system hardening overhead proposal and calculates an alternative RSE that is higher for system hardening overhead work by removing the cost of those supposedly unnecessary replacements.¹⁵⁶⁴

TURN is correct that the RSE score for overhead system hardening is higher than the RSE score for undergrounding in the test year. However, as the pace of PG&E's undergrounding program increases, the RSE for undergrounding becomes higher than the RSE for overhead system hardening.¹⁵⁶⁵ Undergrounding provides permanent, near-total risk reduction and, unlike overhead system hardening, will significantly reduce the need for vegetation management, PSPS, and EPSS on the circuits where it is employed. Moreover, TURN's alternate RSE calculation for overhead system hardening is fundamentally flawed. As PG&E demonstrates in Section 4.3.2.2.1 of this brief, it is unreasonable and unduly expensive over time to not replace overhead components when performing overhead system hardening work. Eliminating certain components for replacement when performing system hardening

¹⁵⁶² TURN-11, p. 26, lines 1-3.

¹⁵⁶³ TURN-11, p. 26, Figure 8.

¹⁵⁶⁴ TURN-11, p. 26, lines 3-6 and Figure 8.

¹⁵⁶⁵ PG&E-04, p. 3-6, Table 3-1.

could result in redundant asset replacements, multiple crew mobilizations and violations of PG&E's standards.

4.2.2.3 Issues Raised By MGRA

MGRA raises three primary issues related to PG&E's decision to focus its proposed system hardening program on undergrounding rather than overhead system hardening. First, MGRA asserts that if PG&E is underestimating the effectiveness of covered conductor, then the argument for choosing undergrounding over covered conductor is weakened.¹⁵⁶⁶ Second, MGRA argues that the lower cost of covered conductor as a wildfire mitigation supports limited use of undergrounding.¹⁵⁶⁷ Third, MGRA argues that because SCE is electing to deploy more covered conductor in its wildfire system hardening program, PG&E should also install more covered conductor.¹⁵⁶⁸

First, PG&E is not underestimating the effectiveness of covered conductor. While MGRA's testimony includes different analyses using data from various utilities that reference different effectiveness values,¹⁵⁶⁹ MGRA candidly acknowledges that PG&E's estimate for covered conductor effectiveness is aligned with SCE's and SDG&E's and that these estimates were collected as the result of a working group directed by Energy Safety Division and that resulted in a comprehensive report and external review by external consultants.¹⁵⁷⁰

Second, PG&E agrees that the cost of undergrounding is greater than the cost of overhead system hardening. However, undergrounding distribution lines during this GRC period in HFTD areas effectively reduces the ignition risk to zero in the approximately 10 percent of the HFTD

¹⁵⁶⁶ MGRA-01, p. 69, lines 11-13.

¹⁵⁶⁷ MGRA-01, p. 69, lines 13-15.

¹⁵⁶⁸ MGRA-01, p. 69, lines 15-17.

¹⁵⁶⁹ MGRA-01, p. 68, line 22 to p. 70, line 4.

¹⁵⁷⁰ MGRA-01, p. 66, lines 11-14.

that is responsible for more than 33 percent of the wildfire risk.¹⁵⁷¹ In this rate case, PG&E is targeting the highest risk areas in the HFTD, which is consistent with MGRA's recommendation that undergrounding be used in specific circumstances where it provides the greatest value.¹⁵⁷²

Third, each of the California utilities needs to select the most appropriate mix of wildfire mitigations based on its own unique set of circumstances, including the unique nature of service territories and wildfire risk. PG&E's service territory is more heavily forested and includes more HFTD miles than other California IOUs' service territories. PG&E's system hardening program includes overhead hardening, undergrounding, remote grid, and line removal. PG&E evaluates each of these options to identify the right application for each distribution circuit segment. Given the difference between SCE's and PG&E's conditions and terrain, it is entirely inappropriate to expect one's mitigation strategies to necessarily apply to the other.¹⁵⁷³

4.2.3 Other Electric Distribution Risk Issues Raised By Parties

In this subsection, PG&E addresses party proposals regarding other electric distribution risk programs, including: (1) PSPS risk modeling; (2) use of PSPS and EPSS to mitigate wildfire risk; (3) the role of RSE values in selecting wildfire mitigations; and (4) Cal Advocates' proposed capital reductions for emergency work.

4.2.3.1 Public Safety Power Shutoff Risk Modeling

Cal Advocates claims that PG&E failed to comply with the 2021 ruling on PG&E's 2020 RAMP report because its GRC testimony does not clearly report the estimated consequences of PSPS events. Cal Advocates recommends that the Commission require PG&E to: (1) consider societal impacts including customer claims when modeling the financial and safety impact of

¹⁵⁷¹ PG&E-17, p. 3-22, lines 1-4.

¹⁵⁷² PG&E-17, p. 3-21, line 24 to p. 3-22, line 7.

¹⁵⁷³ PG&E-17, p. 3-22, lines 13-20.

PSPS on customers; and (2) use the Social Vulnerability Index to expand the consideration of safety consequences to vulnerable communities when assessing PSPS impact.¹⁵⁷⁴

Contrary to Cal Advocates' allegation, PG&E provided a narrative description of its PSPS consequence analysis as part of its prepared testimony¹⁵⁷⁵ and also provided PSPS risk modeling workpapers.¹⁵⁷⁶ PG&E's narrative provides the data needed to support the PSPS consequence analysis and to comply with RAMP.¹⁵⁷⁷ Cal Advocates' proposal to include customer claims in the modeling of customer harms should not be required because these claims have been de minimus – less than \$7,000 between 2019 and 2021.¹⁵⁷⁸

With respect to Cal Advocates' recommendation to use the Social Vulnerability Index, the Commission is addressing this topic in the RDF OIR. PG&E is participating in the RDF OIR and supports the Commission's desired objectives regarding environmental social justice. Since the issues would be one of general application to each utility's RAMP, the OIR is the appropriate venue for addressing the topic raised by Cal Advocates.¹⁵⁷⁹

4.2.3.2 Reliance On PSPS And EPSS To Mitigate Wildfire Risk

MGRA asserts that PG&E's undergrounding program is unnecessary given PG&E's success at reducing ignitions by other means. MGRA states that according to PG&E, the

¹⁵⁷⁴ CALPA-17, p. 41, lines 16-21.

¹⁵⁷⁵ PG&E-17, p. 3-24, lines 1-2 and fn. 71 (citing PG&E-03, p. 3-33, line 12 to p. 3-37, line 9).

¹⁵⁷⁶ PG&E-17, p. 3-24, fn. 72.

¹⁵⁷⁷ PG&E-17, p. 3-23, line 21 to p. 3-24, line 16. PG&E notes that on June 3, 2021, the CPUC ruled on the joint motion filed by the Public Advocates Office and FEITA Bureau of Excellence (the Joint Motion) requesting that PG&E be required to analyze and address concerns regarding its PSPS program. Specifically, the Joint Motion requested that PG&E should analyze the full safety, health, and financial consequences of PSPS on its customers. The CPUC denied the Joint Motion but found it appropriate for PG&E to provide testimony in this GRC. A.20-06-012, *ALJ Lirag's E-Mail Ruling Denying Joint Motion by Cal Advocates and FEITA* (June 3, 2021). PG&E complied with this ruling.

¹⁵⁷⁸ PG&E-17, p. 3-24, line 17 to p. 3-25, line 3.

¹⁵⁷⁹ PG&E-17, p. 3-25, lines 4-14.

combination of PSPS, EPSS, and system hardening to date has reduced the frequency of fire ignitions and wildfire risk by two-thirds, and questions whether the residual risk is severe enough to warrant a multi-billion dollar undergrounding program.¹⁵⁸⁰

MGRA's focus on short-term mitigations, such as EPSS and PSPS, in lieu of long-term mitigations such as undergrounding is not well founded. PG&E's comprehensive wildfire mitigation strategy includes both short-term and long-term mitigations. The primary objective of the undergrounding program is to target the areas where the wildfire threat and PSPS impacts have been the highest. Because outages due to EPSS and PSPS are disruptive to our customers, they are not a feasible long-term solution.¹⁵⁸¹ Moreover, other mitigations, such as vegetation management, are costly and ongoing. Rather, than relying on short-term programs that can significantly impact customers or programs that can be costly and ongoing, PG&E's proposal to implement a long-term solution is the best way to reduce risk and long-term costs.

4.2.3.3 The Role Of RSE Values In Selecting Wildfire Mitigations

TURN asserts that PG&E should have provided more information to indicate how it applied RSEs either at the overall or tranche level to select its wildfire mitigations.¹⁵⁸² PG&E's rebuttal testimony describes how PG&E factored RSEs and risk-related information into its decision-making around mitigations in three ways. First, PG&E ranks its distribution circuits segments by risk score using the models that comprise the WDRM (the Conductor Risk Model, the Vegetation Risk Model, and the Wildfire Consequence Model). Circuit segments are ranked from highest risk to lowest risk to create a prioritization list which is used to guide the planning of work. Second, risk reduction estimates and RSEs generated by PG&E's models are factors PG&E considers when developing its portfolio of work. PG&E seeks to maximize risk reduction while balancing other requirements and other needs such as: maintaining a safe and reliable

¹⁵⁸⁰ MGRA-01, p. 73, lines 10-13.

¹⁵⁸¹ PG&E-17, p. 3-27, lines 1-9.

¹⁵⁸² TURN-11, p. 8, lines 18-21.

system; meeting compliance requirements; addressing customer requests; and identifying operational efficiencies in the planning and execution of work. Third, as discussed in Section 4.2.1 above, the Simplified Wildfire RSE, which is based on PG&E's risk analysis, is the basis for ranking the circuit segments that feed into the three undergrounding program tranches. The circuit segments with the highest Simplified Wildfire RSE are in the first tranche of miles that will be evaluated and likely incorporated into the workplan for this GRC period.¹⁵⁸³ Contrary to TURN's allegation, the evidence indicates that PG&E appropriately used RSEs and other factors to plan its wildfire mitigations.

4.2.3.4 Cal Advocates' Proposed Capital Forecast Reductions To Emergency Work Based On Its Alternate Risk Analysis Are Unreasonable

Cal Advocates contends that because certain risk mitigations implemented by PG&E should reduce the frequency and/or impact of PG&E emergencies compared to the historical norm, the cost to perform emergency work should also be reduced.¹⁵⁸⁴ Cal Advocates' analysis is based on two factors. First, Cal Advocates contends that because PG&E implemented, or will implement, risk reduction activities from 2017 to 2023, it should see reductions in the frequency or impact of ignitions. Second, Cal Advocates claims that PG&E should reduce its forecast cost for certain emergency-based forecasts in its Electric Emergency Recovery and Substation chapters in proportion to the reduced risk due to its risk reduction activities from 2017 to 2023.¹⁵⁸⁵

Cal Advocates' proposal to reduce forecast emergency costs based on its alternative risk analysis is not reasonable for at least two reasons. First, the risk scores presented by PG&E in

¹⁵⁸³ PG&E-17, p. 3-28, line 1 to p. 3-29, line 7.

¹⁵⁸⁴ CALPA-06, p. 11, lines 17-21.

¹⁵⁸⁵ CALPA-06, p. 12, line 14 to p. 14, line 8. The Electric Emergency Recovery forecast is discussed in PG&E-04, Ch. 6 and PG&E-17, Ch. 6; the Substation forecast is discussed in PG&E-04, Ch. 15 and PG&E-17, Ch. 15.

the 2023 GRC for the 2021-2023 period *already reflect the benefit due to past spending on mitigations and controls*. It is because of this spending that the risk score is what it is. The risk scores for 2021-2023 are based on the appropriate estimates of failure data, effectiveness, benefit length, and other program parameters for that time period and take into account the multi-year benefit lengths of controls and mitigations. Cal Advocates' risk score calculations are overly simplistic because they assume a standard rate of risk reduction per dollar spent from 2017-2023 to estimate the 2021-2023 risk reduction scores. This simple analysis does not lead to accurate risk reduction values.¹⁵⁸⁶ Second, the risk reduction scores Cal Advocates uses in its calculations are for mitigations only, while the costs used in the calculations (as indicated by the headers in the calculation table) are for both mitigations and controls.¹⁵⁸⁷ Mixing mitigation risk reduction scores and mitigation and controls costs results in a skewed and inaccurate risk reduction rate.

The Commission should not adopt Cal Advocates' recommendation to reduce PG&E's emergency forecasts. Because mitigations and controls will help reduce the frequency and/or impact of ignitions, PG&E's risk score already reflects this benefit. In other words, the current level of risk – represented by the risk score – accounts for the 2017 to 2023 spending for mitigations and controls. Directionally, the risk reduction values are based on the current estimates of failure data, effectiveness, benefit length and other program parameters. PG&E should not be required to reduce its forecast costs for certain emergency-based forecasts because PG&E's forecast costs already reflect the reduced risk. Because electric emergency work is considered work performed post unplanned failure, the costs associated with this work are

¹⁵⁸⁶ PG&E-17, p. 3-30, line 24 to p. 3-31, line 5.

¹⁵⁸⁷ PG&E-17, p. 3-31, lines 6-9 and fn. 104 (citing CALPA-06, p. 14, Table 6-4, Columns (d) and (e). Note – PG&E was unable to reconcile the 2017-2020 or 2021-2023 spending numbers used by Cal Advocates in its calculation with the source document cited by Cal Advocates but was able to replicate the calculation).

included in the financial consequences of equipment failures. As such, the emergency recovery work is embedded in the quantification of the equipment failure risks.¹⁵⁸⁸

4.3 Wildfire System Hardening

PG&E's System Hardening Program focuses on mitigating the wildfire risk posed by distribution overhead assets in and near Tier 2 and 3 HFTDs in PG&E's service territory. This program targets high wildfire risk miles and applies various mitigation activities to eliminate or reduce those risks, including: (1) undergrounding, (2) overhead system hardening, (3) line removal, (4) remote grid alternatives, and (5) relocation of overhead facilities. Distribution overhead assets represent a high ignition risk due to a combination of high exposure (i.e., many overhead assets located in or crossing through HFTD areas) and proximity to risk factors such as vegetation.

PG&E's System Hardening Program incorporates the five key mitigation activities listed above into a single program for comparison of alternatives, as well as work efficiency. The work in the program also follows PG&E's annual WMP, the most recent of which is the 2022 WMP. The scope, location, and timing of PG&E's system hardening activities will continue to be evaluated as PG&E continues to enhance its wildfire risk modeling; perform more detailed scoping and inspections, estimating, and engineering reviews; and engage with regulators, stakeholders, and customers. Because PG&E's System Hardening Program is still a relatively nascent program subject to input from state agencies, intervenors and other interested parties, some level of uncertainty regarding the exact volume (miles, units) of activities is to be expected. This is one of the primary reasons PG&E proposes to continue use of the Wildfire Mitigation Balancing Account (WMBA) so that customers only pay for the actual work performed; if PG&E's actual costs are lower than PG&E's forecast, the difference will be returned to customers.

¹⁵⁸⁸ PG&E-17, p. 3-31, line 22 to p. 3-32, line 10.

Most intervenors appear to agree with and acknowledge that: (1) wildfire risks have increased in California due to climate change and associated drought; and (1) utility system hardening programs are necessary to address this risk. Despite this common ground, a number of intervenors (with the notable exception of CUE) oppose numerous aspects of PG&E's system hardening activities, including most significantly, PG&E's plan to commence its 10,000 mile undergrounding program. Intervenors' arguments against the undergrounding program are primarily cost-based objections that challenge the scope, timing, and feasibility of PG&E's proposed undergrounding targets and unit costs.

PG&E acknowledges the affordability challenges many customers face, but the consequences of inaction, inadequate action, or delay in addressing core wildfire risks are potentially catastrophic. PG&E's proposed program includes: (1) the near-total elimination of wildfire risk caused by utility assets in the areas undergrounded; (2) reliability improvements with reduced customer impacts caused by PSPS and EPSS outage events as undergrounded lines reduce the need for these mitigation measures; and (3) the potential for long-term savings when undergrounding is compared to overhead hardening and vegetation management costs over time. Undergrounding will also provide long-term resiliency benefits, including reduced weather-related outages and decreased exposure to harsh conditions that degrade or damage overhead facilities. Finally, through the substantial elimination of electric-grid-initiated wildfires, undergrounding will provide environmental benefits and greater economic certainty (e.g., reduced insurance costs¹⁵⁸⁹ and greater confidence in business continuity) for communities and businesses in or near HFTDs as well as all of California more broadly.¹⁵⁹⁰

¹⁵⁸⁹ Tr. Vol. 9, 1625:14-22, PG&E/Martin.

¹⁵⁹⁰ AT&T witness, Dr. Richard Clarke, referred to these benefits as exhibiting the aspect of serving as a public good that benefits both California residents and businesses. Tr. Vol. 13;2576:7 to 2577:20, AT&T/Clarke.

When considering the totality of these benefits, it is evident that undergrounding the riskiest overhead lines in HFTDs is a sound choice. PG&E respectfully urges the Commission to adopt PG&E's System Hardening forecast, so that PG&E is positioned to implement programs over the next several years to aggressively address wildfire risks for the benefit of customers and the public.

PG&E's forecast for System Hardening includes three components that are all tracked in MAT 08W: Overhead Hardening, Underground Hardening, and Community Rebuild.¹⁵⁹¹

PG&E's capital forecast for System Hardening tracked in MAT 08W presented in rebuttal testimony is \$415.654 million in 2021, \$1,030.125 million in 2022, and \$1,512.026 million in 2023, \$2,541.346 million in 2024, \$3,018.650 million in 2025, and \$3,423.762 million in 2026.¹⁵⁹² PG&E's MAT 08W forecast, including the September escalation adjustment, is \$428.523 million in 2021, \$1,122.925 million in 2022, \$1,707.855 million in 2023, \$2,970.020 million in 2024, \$3,537.462 million in 2025, and \$3,922.856 million in 2026.¹⁵⁹³ PG&E did not segregate its system hardening components in the JCE.

PG&E provides additional details regarding the undergrounding and overhead system hardening components of this forecast in Sections 4.3.1 and 4.3.2, respectively.

4.3.1 Undergrounding

In July 2021, PG&E announced a multi-year program to underground 10,000 distribution circuit miles in and near HFTDs in order to aggressively mitigate wildfire ignition risk and improve reliability.¹⁵⁹⁴ PG&E will sequence the execution of underground miles taking into account risk reduction, executability, and community impact.¹⁵⁹⁵ PG&E plans to underground

¹⁵⁹¹ PG&E-04, p. 4.3-51, Table 4.3-11.

¹⁵⁹² PG&E-17, p. 4.3-72, Table 4.3-7, line 1.

¹⁵⁹³ PG&E-67, WP 2, line "[Exhibit 4, Chapter] 4," MWC 08.

¹⁵⁹⁴ PG&E-04, p. 4.3-28, lines 20-21.

¹⁵⁹⁵ PG&E-17, lines 4.3-9, line 10 to p. 4.3-10, line 2.

fewer miles in the initial years and then ramp up in later years to gain efficiencies and incorporate lessons learned.¹⁵⁹⁶ PG&E proposes to underground approximately 3,300 miles from 2023 to 2026, at a forecast cost of approximately \$9,853 million,¹⁵⁹⁷ with the remainder of the undergrounding program to be addressed in subsequent proceedings. Based on PG&E's risk analysis discussed in Section 4.2, PG&E's undergrounding targets in the GRC period represent approximately 10 percent of the overhead miles in HFTD areas and will reduce wildfire risk in HFTD areas by approximately 33 percent.¹⁵⁹⁸ The miles PG&E is planning to underground between 2023 and 2026 have the best combination of risk reduction and feasibility based on the WDRM v3.¹⁵⁹⁹ The 10,000 mile undergrounding program includes certain Community Rebuild work involving the construction of new electric underground infrastructure in the Town of Paradise to mitigate against future wildfire risk in that area following the 2018 Camp Fire.¹⁶⁰⁰ PG&E's undergrounding program is more fully discussed in PG&E's prepared testimony.¹⁶⁰¹

PG&E records costs for undergrounding system hardening work in MAT 08W.¹⁶⁰² PG&E's capital forecast and intervenors' recommended adjustments and positions are summarized below.

¹⁵⁹⁶ PG&E-04, p. 4.3-29, lines 6-10.

¹⁵⁹⁷ PG&E-04, p. 4.3-51, Table 4.3-11, sum of lines 5 and 8.

¹⁵⁹⁸ PG&E stated in its rebuttal testimony that the undergrounding approximately 3,300 miles in this GRC period would reduce risk in the HFTD by approximately 36 percent (PG&E-17, p. 3-9, lines 13-17). During evidentiary hearings PG&E's witness testified that subsequent to filing rebuttal testimony, PG&E revised risk reduction from 36 percent to 33 percent. Tr. Vol. 9, 1676:12-16, PG&E/McGregor.

¹⁵⁹⁹ PG&E-17, p. 3-9, line 11 to p. 3-10, line 3 (including Figure 3-2).

¹⁶⁰⁰ PG&E-04, p. 23-1, lines 11-14.

¹⁶⁰¹ PG&E-04, p. 4.3-28, line 16 to p. 4.3-44, line 8.

¹⁶⁰² PG&E-04, p. 4.3-26, lines 7-14.

**TABLE 4-1:
SYSTEM HARDENING UNDERGROUND - PG&E'S CAPITAL FORECAST^(a)
AND PARTIES RECOMMENDED REDUCTIONS (\$000s)^(b)**

Party	2020	2021	2022	2023	2024	2025	2026
PG&E ^(c)		\$127.654	\$664.125	\$1,246.650	\$2,459.839	\$2,934.732	\$3,337.360
Cal Advocates		\$(95.812)	\$(460.560)	\$(1,050.592)			
TURN				\$(1,079.762)	\$(2,301.630)		\$(3,198.303)
AARP				\$(1,192.578)	\$(2,415.857)	\$(2,907.625)	\$(3,337.360)
Other				\$(1,246.650)	\$(2,459.839)	\$(2,934.732)	\$(3,337.360)
CUE		\$0	\$0	\$0	\$0	\$0	\$0

(a) PG&E-04, p. 4.3-51, Table 4.3-11, lines 4 and 7.

(b) PG&E-17, WP 4.3-1 to WP 4.3-4. Cal Advocates, TURN, and AARP's recommendations are presented as recommended funding levels as opposed to recommended reductions. PG&E has calculated the recommended reduction by subtracting Parties' recommended funding level for system hardening underground from PG&E's forecast. PG&E's forecast amount includes both the 10K underground program and Community Rebuild. For Comcast, MGRA and Wild Tree, see PG&E-17, WP 4.3-5 to WP 4.3-7.

(c) PG&E does not segregate 2020 recorded costs into the individual system hardening components.

Cal Advocates did not comment on PG&E's undergrounding program proposal and instead recommended a reduction to PG&E's June 30, 2021 forecast that was superseded by PG&E's testimony and workpapers served on February 26, 2022. Cal Advocates' recommendation regarding PG&E's original forecast is reflected in the table above but is inapposite because it is not based on PG&E's current 10,000 mile undergrounding program forecast. TURN recommends a substantial reduction based upon a significantly scaled-down undergrounding program of only 200 miles in the rate case period.¹⁶⁰³ AARP recommends that the Commission postpone a decision and authorize one-half of PG&E's original June 30, 2021 forecast for overhead system hardening.¹⁶⁰⁴ Comcast, MGRA, and Wild Tree Foundation all oppose PG&E's 10,000 mile undergrounding program and recommend that the Commission authorize zero funding.¹⁶⁰⁵

¹⁶⁰³ TURN-11, p. 45, lines 4-6.

¹⁶⁰⁴ AARP-01, p. 77, Table, lines 1-2. The table shows AARP's recommended reductions as positive numbers and recommended funding levels as negative numbers.

¹⁶⁰⁵ Comcast-01, p. 12, lines 20-23; MGRA-01, p. 90, lines 5-6; WTF-01, p. 3, line 19 to p. 4 line 2.

In support of their recommendations, intervenors raise issues regarding: (1) the scope, pace, and timing of undergrounding work; (2) affordability in comparison to overhead hardening; (3) PG&E's unit costs for undergrounding; (4) the feasibility challenges that PG&E may face while implementing the undergrounding program; and (5) the sufficiency of the information PG&E provided regarding its proposal. The telecommunication companies, AT&T and Comcast, also raise separate issues regarding the undergrounding program's potential impact on their operations.

In the sections below, PG&E addresses:

- (1) the scope and pace of undergrounding work;
- (2) affordability in comparison to an overhead-focused program;
- (3) undergrounding unit costs;
- (4) PG&E's plans to meet program challenges and implement the program effectively;
- (5) PG&E's commitment to informing communities and stakeholders about undergrounding developments;
- (6) concerns raised by telecommunication parties; and
- (7) other issues raised by parties regarding undergrounding.

4.3.1.1 PG&E's Undergrounding Scope And Pace Of Work Is Reasonable

Several intervenors provided recommendations regarding the scope of PG&E's undergrounding program.

Cal Advocates expresses concern regarding how PG&E developed the mileage targets for the undergrounding program and recommends the Commission require PG&E to provide calculations showing how it determined the forecasted target miles before the Commission considers whether, and to what extent, to approve PG&E's System Hardening program.¹⁶⁰⁶

TURN contends PG&E's undergrounding program is unnecessarily expansive and recommends that PG&E underground 50 miles a year over the forecast period, which TURN

¹⁶⁰⁶ CALPA-17, p. 46, lines 7-14.

claims would allow PG&E to address the top 20 percent of wildfire risk.¹⁶⁰⁷ TURN says that this reflects both a scaling up of the program as well as a more strategic approach to undergrounding.¹⁶⁰⁸

MGRA suggests that the undergrounding program be scaled back to a pilot program until PG&E can demonstrate certain cost efficiencies and that the program could be restricted to only the highest risk tranches.¹⁶⁰⁹

AARP claims that PG&E has not adequately considered less expensive alternatives to undergrounding that might offer similar or greater risk reduction.¹⁶¹⁰

Lastly, Wild Tree Foundation argues that covered conductor is a much more cost effective and less environmentally destructive wildfire mitigation that can be installed and deployed much faster than undergrounding.¹⁶¹¹

The Commission should not scale back PG&E's proposed undergrounding mileage targets, which will provide the highest permanent risk reduction in the highest risk HFTD areas. In the subsections below, PG&E explains that its undergrounding targets address the highest risk miles and parties' proposals to reduce the program scope and pace undermine risk reduction and cost efficiencies.

4.3.1.1.1 PG&E's 10,000 Mile Target Addresses The Highest Amount Of Risk In The Wildfire Risk Areas

As explained in further detail in Section 4.2.1 above, PG&E's undergrounding mileage targets are based on its risk-based modeling efforts. In Exhibit PG&E-17, Chapter 3 (Risk Management), PG&E presented testimony describing how it used the WDRM v3 to help

¹⁶⁰⁷ TURN-11, p. 44, lines 14-18.

¹⁶⁰⁸ TURN-11, p. 44, lines 18-19.

¹⁶⁰⁹ MGRA-01, p. 86, lines 20-25.

¹⁶¹⁰ AARP-01, p. 74 lines 16-18.

¹⁶¹¹ WTF-01, p. 3, line 19 to p. 4, line 2.

determine mileage targets and overhead lines for undergrounding.¹⁶¹² PG&E also has developed and implemented a framework, the Simplified Wildfire RSE, based on the WDRM v3, for risk ranking circuit segments in HFTDs. The Simplified Wildfire RSE framework primarily focuses on wildfire risk reduction in conjunction with other factors (such as feasibility and costs) as decision-making criteria to inform PG&E's selection of projects for the undergrounding program. Based on this analytical modeling, the approximately 3,300 miles that PG&E is planning to underground between 2023-2026 have the best combination of risk reduction and feasibility.¹⁶¹³ PG&E estimates that between 2022-2026 it will underground 88 percent of the miles in the top 20 percent of risk-ranked circuit segments.¹⁶¹⁴ PG&E's risk analysis also shows that its proposed 10,000-mile undergrounding program will provide approximately 73 percent risk reduction in the HFTD areas in PG&E's service territory.¹⁶¹⁵ Section 4.2 discusses risk-analysis issues in further detail.

4.3.1.1.2 Reducing Program Scope And Pace Undermines Risk Reduction And Opportunities For Cost Efficiencies

TURN views undergrounding as a mitigation measure that must be used strategically where it makes the most sense from a cost and risk perspective.¹⁶¹⁶ PG&E generally agrees with this statement. Where PG&E and TURN disagree is in the level of risk reduction that

¹⁶¹² PG&E-17, p. 3-5, line 19 to p. 3-9, line 8.

¹⁶¹³ PG&E-17, p. 3-9, line 11 to p. 3-10, line 3 (including Figure 3-2). PG&E has already developed an initial list of approximately 8,100 risk and feasibility ranked overhead distribution miles in HFTD areas. PG&E's risk and undergrounding program teams are using this list as the basis for identifying specific undergrounding projects that it will pursue during this rate case period. From this list, PG&E will develop its individual undergrounding projects and will rely on its PMO, internal experts and construction partners to implement the projects aligned to the strategies, means and methods that PG&E has already developed and will continue to refine and improve as the program evolves.

¹⁶¹⁴ PG&E 2022 Wildfire Mitigation Plan – Response to Revision Notice (Docket #2022-WMP), July 11, 2022, RN-PG&E-022-03, p. 36.

¹⁶¹⁵ PG&E-17, p. 4.3-67, lines 7-8.

¹⁶¹⁶ TURN-11, p. 44, lines 10-12.

should be pursued. TURN is largely dismissive of the significance of risk reduction to be achieved under PG&E's proposed undergrounding program, and recommends greater deployment of overhead hardening and less deployment of undergrounding – specifically 1,800 miles of covered conductor and 200 miles of undergrounding over the GRC period.¹⁶¹⁷ In making this proposal, TURN fails to account for the risk-reduction effectiveness of undergrounding compared to overhead hardening.

Undergrounding is 99 percent effective at reducing ignition risk while hardened overhead conductor is approximately 62 percent effective.¹⁶¹⁸ Consequently, under TURN's proposal, PG&E would achieve a risk reduction of just 18 percent during the 2024-2026 period, with more overhead conductor (which does not completely eliminate risk), leaving substantial portions of HFTD areas at higher risk.¹⁶¹⁹ In contrast, PG&E's undergrounding proposal would achieve approximately 33 percent permanent risk reduction in the 2024-2026 period.¹⁶²⁰ Over the course of ten years, TURN's proposal would provide 40 percent risk reduction,¹⁶²¹ in comparison to 73 percent risk reduction under PG&E's undergrounding program.¹⁶²² Thus, PG&E's proposal provides greater risk reduction benefits, with permanent risk reduction in the highest risk areas while TURN's proposal leaves substantial portions of HFTD areas at risk.

¹⁶¹⁷ TURN-11, p. 45, lines 4-9.

¹⁶¹⁸ PG&E-04, p. 3-6, lines 9-10.

¹⁶¹⁹ PG&E-17, p. 3-16, lines 18-25.

¹⁶²⁰ PG&E-17, p. 4.3-7, lines 25-30; p. 4.3-21, lines 4-6. PG&E's analysis in this instance included only 2024-2026 because PG&E's 2023 workplan is already in process and was based on an earlier version of the risk model (WDRM v2 for 2023 and WDRM v3 for 2024-2026). PG&E's risk reduction would increase accordingly if 2023 were included in the analysis. For accuracy, PG&E also calculated the risk reduction from TURN's proposal for the entire 2023-2026 period (23 percent). PG&E-17, p. 3-16, fn. 39.

¹⁶²¹ PG&E-17, p. 4.3-38, lines 7-9; p. 4.3-67, lines 4-6, fn. 240.

¹⁶²² PG&E-04, p. 3-3, lines 7-9.

For this reason, undergrounding in HFTD areas should not be capped at 200 miles (50 miles per year) during the GRC period, as proposed by TURN. Overhead hardening and other mitigation alternatives are not as effective as undergrounding in permanently reducing wildfire ignition risk. Undergrounding is a critical wildfire mitigation strategy (a fact that TURN’s own testimony expressly acknowledges)¹⁶²³ that will reduce ignition risk by approximately 99 percent in the areas where PG&E implements it.¹⁶²⁴ PG&E proposes to underground approximately 3,300 miles of primarily the highest risk circuit segments in HFTDs, virtually eliminating electric equipment related wildfire risk in those areas. Based on PG&E’s risk models, approximately 8,000 – 10,000 overhead miles in HFTD areas represent 70 to 80 percent of PG&E’s wildfire risk.¹⁶²⁵ Consequently, once completed, 10,000 miles of undergrounding as proposed by PG&E would virtually eliminate wildfire ignition risk in at least 70 percent of HFTD areas. TURN’s proposed combination of overhead and underground miles would fall far short of this meaningful risk-reduction target. The Commission should not adopt a proposal that does not sufficiently address wildfire risk.

MGRA suggests that the program be scaled back to a pilot program until PG&E can demonstrate certain cost efficiencies.¹⁶²⁶ MGRA also proposes to restrict the program to the highest risk tranches to provide time to analyze other wildfire mitigations.¹⁶²⁷ As discussed above, scaling-back the program would undermine the risk-reduction objectives of the program. It would also limit cost-reduction opportunities. The objective of PG&E’s undergrounding program is to permanently reduce wildfire ignition risk in HFTDs as much as is feasible.

1623 TURN-11, p. 44, lines 24-25 (“TURN views undergrounding as a critical wildfire mitigation strategy – but a targeted and specialized one compared with PG&E’s broad-based approach.”).

1624 PG&E-04, p. 4.3-10, lines 15-16.

1625 PG&E-04, p. 4.3-28, lines 28-32.

1626 MGRA-01, p. 91, lines 3-6.

1627 MGRA-01, p. 86, lines 20-25.

PG&E's proposal is actually consistent with MGRA's comment regarding focusing the program on the highest risk tranches. Indeed, the approximately 3,300 high risk circuit segment miles that PG&E proposes to underground in this rate case period represent the highest risk tranche¹⁶²⁸ and will virtually eliminate wildfire ignition risk in those areas.¹⁶²⁹ In addition, PG&E has already achieved certain cost efficiencies and has achievable plans in place to continue meeting its cost targets, as further explained in Section 4.3.1.4 below. If the scale of the program is reduced, PG&E will not be able to take advantage of the full economies of scale and cost efficiencies that come from the higher number of miles PG&E has planned.

AARP's suggestion¹⁶³⁰ that PG&E has not adequately considered less expensive alternatives to undergrounding that might offer similar or greater risk reduction is incorrect. As explained above, undergrounding permanently reduces ignition risk by approximately 99 percent in the areas where PG&E implements it.¹⁶³¹ Other than line removal, which of course is not an option that can be used in most areas where PG&E provides electric service, there is no less expensive mitigation that offers similar or greater risk reduction. Moreover, undergrounding is not the only risk reduction tool being used by PG&E. PG&E continues to promote a wildfire mitigation strategy using a number of different mitigations appropriate for different circumstances.¹⁶³² In fact PG&E is proposing more than 40 wildfire mitigations in this GRC, of which, approximately 19 mitigate against ignition risk. Other proposed wildfire mitigations reduce the risk of wildfire through activities and services aimed at improving situational awareness, weather forecasting and fire risk modeling. Individual mitigations do not work in

¹⁶²⁸ PG&E-17, p. 3-10, Figure 3-2.

¹⁶²⁹ PG&E-04, p. 4.3-10, lines 15-16.

¹⁶³⁰ AARP-01, p. 74, lines 16-18.

¹⁶³¹ PG&E-04, p. 4.3-10, lines 15-16.

¹⁶³² PG&E-04, p. 4-1, line 16 to p. 4-11, line 30.

isolation to reduce risk.¹⁶³³ Rather, the full complement of PG&E’s proposed mitigations working together in combination provides the most risk reduction.¹⁶³⁴ PG&E discusses the benefits of certain of these mitigations in Section 4.4. PG&E describes the benefits of all its wildfire mitigation programs in its opening testimony.¹⁶³⁵

Finally, Wild Tree Foundation’s assertion that covered conductors are a more cost effective and less environmentally destructive wildfire mitigation¹⁶³⁶ ignores that covered conductors do not eliminate all risk, as discussed above.

4.3.1.2 PG&E’s Undergrounding Program Is Cost-Effective In Comparison To Alternatives To Achieve The Same Level Of Risk Reduction

TURN asserts that PG&E provides no support in testimony for its program based on RSE scores or a clear analysis that 10,000 miles, or the 3,300 miles forecast for the 2023-2026 GRC period, is the right scope that correctly balances affordability and safety.¹⁶³⁷ Not so. PG&E’s analysis (provided to TURN before it submitted its testimony) demonstrates that PG&E’s proposed undergrounding program strikes the right balance.¹⁶³⁸

To demonstrate why PG&E’s undergrounding program provides an appropriate affordability-safety balance, PG&E conducted an analysis comparing the effectiveness of the underground-hardening-focused program (as proposed by PG&E) to a hypothetical overhead-focused one that would deliver the same amount of risk reduction. Providing a fair apples-to-

¹⁶³³ PGE-17, p. 4.3-34, lines 11-16.

¹⁶³⁴ PG&E-17, p. 4.3-34, lines 16-18.

¹⁶³⁵ PG&E-04, Ch. 4.1, Situational Awareness and Forecasting; Ch. 4.2 PSPS Operations; Ch. 4.3 System Hardening, Enhanced Automation and PSPS Impact Mitigations; Ch. 4.4 Community Wildfire Safety Program (CWSP) Program Management Organization; Ch. 4.5 CWSP Information Technology; Ch. 4.6 Enhanced Powerline Safety Settings; and Ch. 9, Vegetation Management.

¹⁶³⁶ WTF-01, p. 3, line 19 to p. 4, line 2.

¹⁶³⁷ TURN-11, p. 32, lines 9-11.

¹⁶³⁸ PG&E-17, PG&E’s response to Data Request TURN_154-Q14Supp01 and Attachment TURN_154-Q14Supp01Atch01, dated 5/23/22, pp. App A-76 to App A-84.

apples comparison, PG&E's analysis specifically compared the mitigation effectiveness, costs, and savings of PG&E's 10-year undergrounding program to an overhead-focused program that would deliver the same risk reduction benefits.¹⁶³⁹ The analysis showed that overhead-focused program would be less effective, would cost more, and would save less than PG&E's undergrounding program.¹⁶⁴⁰

For specifics on the analysis, PG&E's proposed hardening program, which consists of 10,000 miles of undergrounding and 1,000 miles of overhead hardening through 2031, will deliver approximately 70 percent risk reduction in HFTD areas in PG&E's service territory.¹⁶⁴¹ To determine whether overhead-focused hardening program is cost-effective in comparison to PG&E's proposed undergrounding program, PG&E calculated the size the overhead-focused program would have to be in order to provide the same level of risk-reduction as the undergrounding program. PG&E calculated that the overhead-focused program would require approximately 21,000 miles of overhead hardening and 3,000 miles of undergrounding to achieve the same level of risk reduction to PG&E proposed undergrounding program.¹⁶⁴²

When putting these figures in terms of costs, the analysis further showed that in comparison to PG&E's undergrounding proposal, an overhead-focused program would involve: (1) total capital costs (2022-2031) that are 71 percent higher; (2) a total revenue requirement (2022-2031) that is 99 percent higher; and (3) total operations and maintenance (O&M) expense reduction (2022-2031) that is 49 percent less.¹⁶⁴³ Simply put, the overhead program would cost more, with nearly double the costs and revenue requirement.

¹⁶³⁹ PG&E-17, p. 4.3-65, lines 15-17.

¹⁶⁴⁰ PG&E-17, p. 4.3-65, lines 11-13.

¹⁶⁴¹ PG&E-17, p. 4.3-67, lines 7-8.

¹⁶⁴² PG&E-17, PG&E's response to Data Request TURN_154-Q14Supp01 and attachment TURN_154-Q14Supp01Atch01, dated 5/23/22, pp. App A-76 to App A-84.

¹⁶⁴³ PG&E-17, p. 4.3-65, lines 26-30.

In addition, the undergrounding program is less disruptive to customers (i.e., less construction related disruptions given that less work is needed to achieve the expected risk reduction), provides greater reliability including fewer PSPS and/or EPSS outages, and provides greater long-term savings than the overhead focused program through reduced lifetime O&M expenses and other avoided -costs.¹⁶⁴⁴

TURN claims it conducted its own analysis comparing the costs and savings of overhead hardening to undergrounding. Their analysis is deeply flawed. TURN attempted to compare annual revenue requirements for undergrounding to potential savings if 10,000 miles are undergrounded from 2021-2031.¹⁶⁴⁵ TURN determined that even with operational and customer savings included, undergrounding 10,000 miles would result in a net cost of over \$13 billion on a present value basis, far exceeding the \$6.7 billion cost on a present value basis that ratepayers would incur if PG&E installed covered conductor on 10,000 miles. TURN then reasoned that covered conductor is significantly more affordable than undergrounding even when one considers long-term savings from undergrounding.¹⁶⁴⁶ TURN misses the point and compares the wrong things to reach a faulty conclusion.

PG&E agrees that savings from the undergrounding program will not be greater than the cost of undergrounding. However, what is important is that there will be certain long-term savings directly related to PG&E's undergrounding program. For example, costs related to PG&E's vegetation management program will decrease as the pace of undergrounding increases (because vegetation management is not needed for underground lines to the same extent as overhead lines).¹⁶⁴⁷ In addition, undergrounding lines helps to protect against hardened

¹⁶⁴⁴ PG&E-17, PG&E's response to Data Request TURN_154-Q14Supp01 and attachment TURN_154-Q14Supp01Atch01, dated 5/23/22, pp. App A-76 to App A-84.

¹⁶⁴⁵ TURN-11, p. 42, lines 5-6.

¹⁶⁴⁶ TURN-11, p. 43, lines 2-7.

¹⁶⁴⁷ PG&E-17, p. 4.3-66, lines 21-22.

overhead assets that could subsequently be destroyed in a wildfire or other natural disaster and would need to be replaced.¹⁶⁴⁸ This has the potential to significantly lower restoration costs following such an event. PG&E also anticipates that the undergrounding program will result in improved reliability and reduced customer impacts as PG&E relies less on PSPS and EPSS to mitigate against wildfires.¹⁶⁴⁹ Further, PG&E expects that underground lines will last at least 50 years before they need to be replaced and expects that O&M expenses will be less in the long run than O&M costs for overhead assets.¹⁶⁵⁰

TURN's analysis also fails to consider the amount of the wildfire risk reduction obtained through PG&E's proposed undergrounding program, causing TURN to compare the wrong things and reach a faulty conclusion. To determine which approach (undergrounding or overhead hardening) is more cost-effective, TURN should compare mitigation alternatives that deliver the same amount of wildfire risk reduction. PG&E estimates that installing 10,000 miles of overhead covered conductor would result in approximately 49 percent risk reduction in the HFTD,¹⁶⁵¹ far less than the 73 percent risk reduction PG&E currently estimates that it will achieve through its 10,000 mile undergrounding program.¹⁶⁵² Incorporated into these relative risk reduction values is the effectiveness of the different mitigations - undergrounding is 99 percent effective at reducing ignition risk compared to 62 percent effectiveness for overhead system hardening.¹⁶⁵³

An additional shortcoming of its analysis, TURN also does not consider customer bill

¹⁶⁴⁸ PG&E-17, p. 4.3-66, lines 22-24.

¹⁶⁴⁹ PG&E-17, p. 4.3-66, lines 25-28.

¹⁶⁵⁰ PG&E-17, p. 4.3-66, line 28 to p. 4.3-67, line 2; and PG&E's response to Data Request TURN_154-Q13, dated 3/22/22, pp. App A-74 to App A-75.

¹⁶⁵¹ PG&E-17, p. 4.3-67, lines 4-6, fn. 240.

¹⁶⁵² PG&E-04, p. 3-3, lines 7-9.

¹⁶⁵³ PG&E-04, p. 3-6, lines 13-15.

impacts. To fill this gap, PG&E analyzed the average monthly cost to customers for its undergrounding program and compared that to the average monthly cost to customers for an overhead-focused program that delivers the same risk reduction. For the undergrounding program, the average monthly cost to customers would be approximately \$16 per month.¹⁶⁵⁴ (For clarity, this is not a monthly bill increase estimate, it is the dollar amount of an average residential non-CARE electric customer's total bill that would fund the underground proposal).¹⁶⁵⁵ In contrast, the average monthly cost to customers for an overhead-focused program that delivers the same risk reduction would be approximately \$33 for the average non-CARE electric customer.¹⁶⁵⁶ Again, this shows that a risk-equivalent overhead-focused program would be double the cost of PG&E's proposed undergrounding program. Or put another way, PG&E's undergrounding program is twice as cost-effective in comparison to an overhead-focused hardening program, when considering equivalent risk reduction scenarios.

4.3.1.3 PG&E Is Able To Effectively Address Undergrounding Implementation Challenges

Many intervenors are skeptical of the feasibility of PG&E's undergrounding program, particularly in regard to the proposed overall size and pace of the program. These concerns are misplaced.

TURN states that PG&E's proposal to underground 3,300 miles from 2023-2026 would require an installation pace that is faster by orders of magnitude than any historical undergrounding project or program.¹⁶⁵⁷ TURN bases this opinion on PG&E's undergrounding work completed from 2015 to 2021¹⁶⁵⁸ and documentation related to PG&E's Request for

¹⁶⁵⁴ PG&E-17, p. 4.3-67, lines 21-22.

¹⁶⁵⁵ PG&E-17, p. 4.3-67, lines 22-24.

¹⁶⁵⁶ PG&E-17, PG&E's response to Data Request Comcast_001-Q03 and attachment Comcast_001-Q03Atch01, dated 6/7/22, pp. App A-47 to App A-68.

¹⁶⁵⁷ TURN-11, p. 35, lines 1-3.

¹⁶⁵⁸ TURN-11, p. 35, line 5 and Table 10.

Information (RFI) for undergrounding work.¹⁶⁵⁹ Cal Advocates claims there is insufficient evidence that PG&E can achieve either the ambitious mileage target or the substantial unit cost reduction it proposes.¹⁶⁶⁰

PG&E recognizes that its 10,000 mile undergrounding program is larger than any undergrounding work it has done in the past. But the past is not the proper measure, because the means and objectives were not the same (it is like suggesting that a bird cannot fly, simply because it is observed sitting in a tree. TURN, Cal Advocates, and other parties who question the feasibility of the program, including the planned scope and pace, fail to appreciate the extensive work and progress PG&E has made to plan for and implement the program. In the subsections below, PG&E explains:

1. PG&E has been able to scale up undergrounding based on projects to date;
2. PG&E has established a Program Management Office (PMO) and positioned itself to meet program challenges;
3. PG&E's sourcing strategy will help it address resource needs;
4. PG&E is actively engaging with stakeholders; and
5. PG&E is taking steps to reduce project risk.

4.3.1.3.1 PG&E Has Been Able To Scale-Up Its Undergrounding Based On Projects To Date

As an initial matter, PG&E has made significant progress in scaling up its underground program to achieve the proposed mileage targets. As explained in testimony, in early 2022, PG&E onboarded an industry leading engineering firm with substantial expertise in delivering large projects as PG&E's program management partner.¹⁶⁶¹ PG&E is also leveraging its

¹⁶⁵⁹ TURN-11, p. 36, line 1.

¹⁶⁶⁰ CALPA-17, p. 34, lines 1-2.

¹⁶⁶¹ PG&E-17, p. 4.3-33, lines 13-15.

Foundry¹⁶⁶² tool to aggregate a significant amount of data to better understand the profile of the 10,000 mile program portfolio including geological profiles, gradient, service density, road adjacency, and water crossings; this insight will allow PG&E to plan and sequence the work to achieve both mileage and cost targets.¹⁶⁶³ Finally, PG&E has deployed more efficient construction methods, such as rock wheels, plows, and boring tools, that are resulting in faster, more cost-effective mileage completion.¹⁶⁶⁴

4.3.1.3.2 PG&E Has Established a PMO And Positioned Itself To Meet Program Challenges

In addition, PG&E is taking proactive measures to address the challenges of executing the program including:

- Measures to reduce unit costs (See Sections 4.3.1.4.2 and 4.3.1.4.3);
- Prioritizing undergrounding where it can have the greatest impact on reducing wildfire risk and PSPS outages for customers (See Section 4.3.1.1.1);
- Managing program risk (See Section 4.3.1.3.5);
- Improving sourcing strategies (See Section 4.3.1.3.3);
- Forming an Underground Advisory Group to advise PG&E on large scale planning (See Section 4.3.1.3.4); ¹⁶⁶⁵
- Taking an “all hands on deck” approach to resourcing to scale up to the level of undergrounding planned for the next several years (See Section 4.3.1.3.3);¹⁶⁶⁶
- Working closely with external stakeholders to ensure that PG&E’s plans are responsive to their interests and concerns (See Section 4.3.1.3.4);¹⁶⁶⁷ and

¹⁶⁶² Palantir Foundry is an operating system that works to close the loop between analytics and operations, empowering enterprise-wide decision optimization. PG&E-17, p. 4.3-33, fn. 100.

¹⁶⁶³ PG&E-17, p. 4.3-33, lines 15-20.

¹⁶⁶⁴ PG&E-17, p. 4.3-33, lines 20-22.

¹⁶⁶⁵ PG&E-04, p. 4.3-31, lines 29-34.

¹⁶⁶⁶ PG&E-04, p. 4.3-42, lines 6-8.

¹⁶⁶⁷ PG&E-04, p. 4.3-44, lines 2-8.

- Gathering information from domestic and international project, engineering and construction firms related to construction methods, cost assumptions, equipment and materials, program risks, safety, technology innovations, program structure and labor through an RFI process (See Sections 4.3.1.3.1 and 4.3.1.3.4).¹⁶⁶⁸

PG&E has taken actions to scale the underground program to deliver on the mileage targets by creating a dedicated PMO that will provide the depth and breadth needed to meet the program targets.¹⁶⁶⁹ Through the PMO, PG&E is optimizing the delivery process and standing up the organization with resources solely focused on the delivery of the underground work. Given the volume and complexity of work, a management structure with central and regional functions will drive consistency and focus delivery at the workforce. Regional teams will develop local supplier and community ties and be responsible for detailed design and delivery of projects.¹⁶⁷⁰ This structure reflects international best practices and will provide the capacity, controls and consistency needed to meet the undergrounding program objectives.¹⁶⁷¹

In addition, the Undergrounding PMO is implementing a streamlined delivery process focused on identifying and implementing efficiencies in scoping, estimating, dependency management (permitting, land and environment, materials, resourcing/scheduling) and construction.¹⁶⁷² The process improvements will provide significant efficiency benefits by pulling activities forward and performing them in parallel versus in a sequential manner. The current process to deliver undergrounding work takes approximately 19-36 months.¹⁶⁷³ Through targeted improvements, PG&E anticipates this process will be reduced to 12-24

¹⁶⁶⁸ PG&E-04, p. 4.3-31, lines 1-8.

¹⁶⁶⁹ PG&E-17, p. 4.3-24, lines 25-28.

¹⁶⁷⁰ PG&E-17, p. 4.3-25, lines 3-5.

¹⁶⁷¹ PG&E-17, p. 4.3-25, lines 5-7.

¹⁶⁷² PG&E-17, p. 4.3-25, lines 8-11.

¹⁶⁷³ PG&E-17, p. 4.3-25, lines 13-14.

months.¹⁶⁷⁴ Process improvements at each step will increase throughput, build and enhance design capabilities, improve management of dependencies, and develop an experienced pool of construction resources to deliver projects safely for the communities PG&E serves.

An additional cost-reduction strategy involves increasing project size to unlock economies of scale in construction.¹⁶⁷⁵ Currently, projects range from less than a mile to two miles. The PMO will bundle work into packages ranging from 10 to 30 miles.¹⁶⁷⁶ Benefits of this improvement include providing certainty of work for contractors, which will enable them to invest in new equipment, engage the supply chain in a more meaningful way, and expand pools of skilled labor.¹⁶⁷⁷ Other notable cost-improvements include developing expertise internally and externally to drive continuous improvements; limited redeployment of construction resources to maximize production efficiency; and developing a skilled workforce dedicated to undergrounding.¹⁶⁷⁸

Further, PG&E has taken steps to identify the 10,000-mile portfolio that will make up the undergrounding program.¹⁶⁷⁹ The ability to bundle work into larger packages, as discussed above, is based on visibility into the long-term portfolio.

Still more, PG&E is also reviewing and updating standards and specifications in preparation for the undergrounding program.¹⁶⁸⁰ Due to the limited undergrounding that has occurred in rural areas, there is an opportunity to improve and right size the standards and

¹⁶⁷⁴ PG&E-17, p. 4.3-25, lines 14-16.

¹⁶⁷⁵ PG&E-17, p. 4.3-25, lines 20-21.

¹⁶⁷⁶ PG&E-17, p. 4.3-25, lines 22-23.

¹⁶⁷⁷ PG&E-17, p. 4.3-25, lines 23-26.

¹⁶⁷⁸ PG&E-17, p. 4.3-25, lines 26-29.

¹⁶⁷⁹ PG&E-17, p. 4.3-25, lines 30-31.

¹⁶⁸⁰ PG&E-17, p. 4.3-26, lines 3-4.

specifications for rural installations.¹⁶⁸¹ To date, PG&E has revised requirements for secondary boxes as well as a standard for backfill, each revision providing opportunities for more efficient undergrounding work by reducing materials needs (i.e., fewer boxes per mile) and construction time (i.e. shallower trenches requiring less digging and less soil handling).¹⁶⁸²

PG&E is also taking steps to proactively engage with stakeholders and communities within HFTD areas that may be directly impacted by the undergrounding program.¹⁶⁸³ PG&E has also released preliminary maps of 2023 work to the agencies and general public.¹⁶⁸⁴ By providing visibility into the longer-term work plan, PG&E can create opportunities to better sequence work and coordinate with other capital improvement projects.

Finally, the dedicated delivery organization will be structured to allow the program to scale in line with the mileage targets.¹⁶⁸⁵ The organization will consist of central functions that provide consistency and standardization across the regions where the projects will be delivered by dedicated teams.¹⁶⁸⁶ This approach allows the program to expand regional/project teams as needed to meet the scale of projects while maintaining a programmatic approach to delivery.

4.3.1.3.3 PG&E's Sourcing Strategy Will Address Resource Needs To Help Ensure Project Success

Notwithstanding all the program and project management tools PG&E is implementing to ensure project success, several intervenors are skeptical about PG&E's ability to achieve its undergrounding program objectives due to external market issues. Comcast, for example, is concerned that PG&E is apt to encounter challenges such as shortages of materials and

¹⁶⁸¹ PG&E-17, p. 4.3-26, lines 4-7.

¹⁶⁸² PG&E-17, p. 4.3-26, lines 8-12.

¹⁶⁸³ PG&E-17, p. 4.3-26, lines 14-17.

¹⁶⁸⁴ PG&E-17, p. 4.3-26, lines 17-22.

¹⁶⁸⁵ PG&E-17, p. 4.3-26, lines 25-26.

¹⁶⁸⁶ PG&E-17, p. 4.3-26, lines 26-28.

equipment, supply chain issues, shortages of construction resources, and limited labor resources.¹⁶⁸⁷ PG&E recognizes that a program of this size and scope requires significant planning, management and support to be successful. Thus, as discussed above, PG&E established a PMO that will provide the capacity, controls and consistency needed to meet the undergrounding program objectives and is working to improve design and construction standards, materials management and strategic sourcing.¹⁶⁸⁸

Comcast also fails to consider the observations of its own witness that lessons learned can be incorporated in project plans as a utility gains experience with undergrounding.¹⁶⁸⁹ Relatedly, while focusing only on potential challenges, Comcast does not acknowledge the expected benefits of completing the program at the scale proposed by PG&E.

PG&E is also actively addressing potential resource challenges, working with external stakeholders and collecting information from industry experts regarding materials, equipment and construction resources.¹⁶⁹⁰ Indeed, PG&E's "all hands on deck" sourcing strategy is centered around building a cross-functional team made up of PG&E employees and contractors with expertise and experience across the undergrounding program elements. This cross-functional team includes employees throughout Electric Operations such as those who work in the Underground Program Management Office, Electric Asset Strategy, Grid Design, System Safety and Risk Management, Projects and Construction, Mapping, Estimating, Engineering, and Regulatory Compliance among others.¹⁶⁹¹ Along with employees in Electric Operations, PG&E employees in other organizations such as Wildfire Risk Management, Land and Environmental, Law, Sourcing, Information Technology, Enterprise and Operational Risk

¹⁶⁸⁷ Comcast-02, p. 4, line 19 to p. 5, line 2.

¹⁶⁸⁸ PG&E-17, p. 4.3-25, lines 5-11.

¹⁶⁸⁹ Tr. Vol. 13, 2516:9 to 2517:20, Comcast/Votaw.

¹⁶⁹⁰ PG&E-17, p. 4.3-27, lines 19-22.

¹⁶⁹¹ PG&E-17, p. 4.3-27, lines 28-32.

Management, Regulatory Relations, Enterprise Health and Safety, and Customer Care support the undergrounding program as well.¹⁶⁹² Additionally, PG&E issued an RFI in May 2022 and held a supplier summit in June 2022 to identify additional civil, electrical, project management, environmental, land, permitting, material, equipment, and other project support resources to support the program.¹⁶⁹³ PG&E received responses from dozens of firms and will use these responses to shape upcoming events to engage resources to support the undergrounding program.¹⁶⁹⁴

4.3.1.3.4 PG&E’s Active Engagement With Stakeholders Ensures Expert And Other Valuable Input From Industry Leaders And Other Groups Is Incorporated Into Project Plans

In addition to the activities discussed above, PG&E is coordinating with external stakeholders to support PG&E’s undergrounding efforts. Foremost in PG&E’s effort to engage with external stakeholders is the Undergrounding Advisory Group, which functions as a forum for PG&E to share information and receive input and ideas from external stakeholders such as: environmental and land stewardship organizations; environmental and social justice groups; transportation; academia; agriculture; labor; utilities and telecommunications companies; public safety bodies; counties and tribes; and state and other regulatory agencies.¹⁶⁹⁵ Working with these stakeholders has helped the program to evolve in a variety of ways. For example, PG&E is exploring opportunities for partnerships including bioenergy facilities and California’s Middle-Mile Broadband initiative, which is a \$3.25 billion funding source expected to support the construction of approximately 8,000 miles of underground broadband infrastructure.¹⁶⁹⁶

¹⁶⁹² PG&E-17, p. 4.3-27, line 32 to p. 4.3-28, line 5.

¹⁶⁹³ PG&E-17, p. 4.3-28, lines 10-14.

¹⁶⁹⁴ PG&E-17, p. 4.3-28, lines 14-16.

¹⁶⁹⁵ PG&E-17, PG&E’s response to Data Request TURN_154-Q25, dated 3/22/22, pp. App A-87 to App A-89.

¹⁶⁹⁶ State of California Middle-Mile Broadband Initiative (June 2022), at: <https://middle-mile-broadband-initiative.cdt.ca.gov/> (as of November 1, 2022).

Potential partnership benefits could include expedited approvals, improved scalability, coordinated and faster construction, improved stakeholder buy-in, and reduced community impacts. PG&E is also working with telecommunications companies including AT&T, Comcast, California Cable and Telecommunications and rural telecommunications associations to share information and identify areas for collaboration on undergrounding projects.¹⁶⁹⁷

To collect additional information from industry experts, PG&E issued an RFI to engineering and construction firms in August 2021,¹⁶⁹⁸ one month after PG&E initially announced the 10,000 mile program. The intent of the RFI was to collect general information about construction methods, cost assumptions, construction means and methods, risk, labor structures and other related topics.¹⁶⁹⁹ The information received in response to the RFI has been valuable and was used to further inform PG&E's undergrounding plans.¹⁷⁰⁰

4.3.1.3.5 PG&E Has Taken Meaningful Steps To Reduce Project Risks

While the 10,000 mile undergrounding program is one of the largest programs PG&E has ever undertaken, PG&E has evaluated program risks and potential pitfalls and taken appropriate steps to reduce and avoid them. As explained in testimony, when a large project (mega-project) fails, the reasons for the failure generally fall into one or more categories: (1) poor organization and project management, (2) poorly defined or missing objectives; (3) insufficient project personnel resources; (4) ineffective project planning; (5) problems with suppliers; and (6)

¹⁶⁹⁷ PG&E-17, p. 4.3-29, lines 1-5.

¹⁶⁹⁸ TURN stated that in response to PG&E's RFI vendors provided heavily caveated ranges of potential costs and "ramping plans." (TURN-11, p. 36, lines 1-2). The RFI was submitted in August 2021, one month after PG&E initially announced the 10,000 mile program. The RFI was just that – a way for PG&E to collect information from experienced industry leaders. It was meant to be an early data collection activity and was never intended to be used as a basis for executing contracts for undergrounding work or for determining final scopes of work or contract pricing.

¹⁶⁹⁹ PG&E-04, p. 4.3-31, lines 1-8.

¹⁷⁰⁰ PG&E-04, p. 4.3-31, lines 8-17.

technical problems.¹⁷⁰¹ PG&E is proactively addressing these potential program risk issues by: developing a PMO-led organization, governance, and control structure that meets the scope and scale of the program; driving clarity and enterprise-wide alignment on the program's strategic objectives underpinned by a transparent performance management framework; leveraging an experienced PG&E team complemented by industry leaders in mega-project delivery; developing a multi-year strategy and work plan coordinating all the program functions; and optimizing technical specifications and standards to drive efficiencies in design and construction.¹⁷⁰²

4.3.1.4 PG&E's Unit Cost Targets Are Reasonable And Achievable

MGRA argues that PG&E has not produced substantial evidence that PG&E will be able to significantly reduce the cost of undergrounding as forecast, particularly in the highest fire threat areas that may be in more challenging terrain. It also claims that PG&E's testimony lacks specificity regarding its plans to underground distribution lines at a reduced cost.¹⁷⁰³ Cal Advocates is also skeptical that PG&E will be able to meet unit cost targets.¹⁷⁰⁴ In the subsections below, PG&E explains that: (1) PG&E's cost analysis confirms its unit cost forecast is achievable; (2) PG&E has identified opportunities to reduce construction costs; and (3) PG&E has identified other cost reduction drivers.

4.3.1.4.1 PG&E's Cost Analysis Confirms Its Forecast Unit Costs Are Achievable

PG&E conducted a detailed cost analysis to support its forecast that it will be able reduce underground cost per mile by \$1.25 million by 2026.¹⁷⁰⁵ The objective of the cost analysis was to develop an average cost per mile based upon project complexity. As part of this analysis,

¹⁷⁰¹ PG&E-17, p. 4.3-33, lines 25-29.

¹⁷⁰² PG&E-17, p. 4.3-33, line 29 to p. 4.3-34, line 7.

¹⁷⁰³ MGRA-01, p. 84, lines 26-30.

¹⁷⁰⁴ CALPA-17, p. 34, lines 1-2.

¹⁷⁰⁵ PG&E-17, p. 4.3-31, lines 6-9.

PG&E analyzed unit pricing from five different construction firms.¹⁷⁰⁶ The complexity criteria considered in the analysis included water crossings, likelihood of rock, gradient, service density per mile, road adjacency, and spoils haul.¹⁷⁰⁷ PG&E calculated an average construction cost per mile using the information provided by the construction firms and added other items not included in the construction costs such as PG&E's internal labor and PG&E administrative and general (A&G) amounts.¹⁷⁰⁸ Using this data, PG&E calculated the range of potential unit costs as follows: high complexity case of \$4.37 million/mile, medium-complexity case of \$3.02 million/mile, and low-complexity case of \$2.42 million/mile.¹⁷⁰⁹ This analysis demonstrates that the forecast unit costs for undergrounding can be achieved. It is also important to note that these represent averages and do not reflect that full realization of cost-savings activities discussed in the next section.

4.3.1.4.2 PG&E Has Identified Opportunities To Reduce Construction Costs

PG&E's forecast assumes that by 2026 PG&E will have reduced the underground cost per mile by at least one third or \$1.25 million dollars.¹⁷¹⁰ PG&E has already identified specific cost reduction opportunities and has started to implement them. For example, approximately two-thirds of the cost per mile is associated with construction activities such as digging trenches, installing materials and disposing of soil.¹⁷¹¹ To reduce unit costs, PG&E looked for ways to address these key cost drivers. PG&E recently updated one of its underground design standards to reduce the depth at which cable needs to be buried from 36 inches to 30 inches in certain

¹⁷⁰⁶ PG&E-17, p. 4.3-31, line 9.

¹⁷⁰⁷ TURN-17, p. 4.3-31, lines 11-13.

¹⁷⁰⁸ PG&E-17, p. 4.3-31, lines 13-16.

¹⁷⁰⁹ PG&E-17, p. 4.3-31, Table 4.3-5.

¹⁷¹⁰ PG&E-04, p. 4.3-29, Table 4.3-8, line 2.

¹⁷¹¹ PG&E-17, p. 4.3-30, lines 21-23.

areas; this change results in improved construction timelines and reduced construction costs across large portions of the portfolio.¹⁷¹² Another example is taking advantage of the volume of miles by sequencing the work in larger and longer segments and competitively bidding these larger work bundles.¹⁷¹³ PG&E began these efforts at a small scale for the 2022 underground miles and saw a 10 percent reduction from prior years' costs.¹⁷¹⁴

4.3.1.4.3 PG&E Has Identified Other Cost Reduction Drivers

In addition to cost reduction opportunities related to construction activities, PG&E has identified other cost-reduction drivers that it will continue to evaluate over the course of the program. PG&E is currently focusing on developing and implementing cost reduction strategies targeting the highest areas of cost drivers.¹⁷¹⁵ Of note, current efforts are focused on: implementing new design and construction standards to avoid unnecessary costs; delivering a strategic approach to construction contracting at favorable pricing terms; and scaling materials management to increase cost-efficiencies.¹⁷¹⁶

The opportunities to dig a trench at 30 inches rather than 36 inches is one example of a new design and construction standard that will cut time and costs.¹⁷¹⁷ PG&E is also evaluating other promising opportunities to reduce construction costs, including potentially: (1) reducing the minimum cover and native backfill; (2) optimizing the allowable installation length of cable in conduit; and (3) eliminating unnecessary equipment such as secondary boxes.¹⁷¹⁸

¹⁷¹² PG&E-17, p. 4.3-30, line 25 to p. 4.3-31, line 1.

¹⁷¹³ PG&E-17, p. 4.3-31, lines 1-3.

¹⁷¹⁴ PG&E-17, p. 4.3-31, lines 3-5.

¹⁷¹⁵ PG&E-17, p. 4.3-32, lines 5-7.

¹⁷¹⁶ PG&E-17, p. 4.3-31, line 29 to p. 4.3-32, line 2.

¹⁷¹⁷ PG&E-17, p. 4.3-30, line 25 to p. 4.3-31, line 1.

¹⁷¹⁸ PG&E-17, p. 4.3-32, lines 7-10.

PG&E is also pursuing cost-reduction opportunities related to strategic sourcing. For example, PG&E is developing contracts that allow for work to begin quickly and efficiently based on the project location, size, and available resources.¹⁷¹⁹ This will allow for quick contract adjustments based on learnings and feedback and will include price incentives to leverage project scale and new technologies. PG&E is working to identify the right mix of qualified, diverse partners to improve the ability to scale and meet program needs.¹⁷²⁰ This includes building long-term relationships with contractors and material suppliers and incentivizing new partners to enter the market and invest in specialty equipment and driver innovation.¹⁷²¹

Finally, PG&E is also implementing changes to its current materials management practices to reduce costs and ensure the availability of materials. Key activities include: establishing a comprehensive materials readiness report for all 2022 projects; estimating inventory exhaustion dates for 2022 projects; updating the bill of materials using forecast/designed project miles; increasing supply chain diversity; and reducing materials customization.¹⁷²²

4.3.1.5 PG&E Is Committed To Updating Communities And Stakeholders Of Specific Undergrounding Activities

Comcast and AARP criticize the sufficiency of information overall provided to stakeholders regarding PG&E's undergrounding program.¹⁷²³ These criticisms are unwarranted.

¹⁷¹⁹ PG&E-17, p. 4.3-32, lines 20-22.

¹⁷²⁰ PG&E-17, p. 4.3-32, lines 24-26.

¹⁷²¹ PG&E-17, p. 4.3-32, lines 26-28.

¹⁷²² PG&E-17, p. 4.3-32, lines 14-18.

¹⁷²³ Comcast-01, p. 10, lines 16-20; AARP-01, p. 74, line 9 to p. 75, line 6.

PG&E continues to provide information about the scope of its undergrounding proposal as it becomes available, and will provide that information to all communities, potentially-impacted utilities, and other interested stakeholders as appropriate. PG&E is engaging with communities, customers, and other stakeholders to share information about the program, and has plans to enhance that engagement over time. These communications include mailers, automated phone calls and onsite meetings with customers when necessary.¹⁷²⁴ PG&E will also provide notice of upcoming vegetation and construction work approximately two weeks prior to PG&E personnel being on customer property.¹⁷²⁵ Additionally, PG&E has made Customer Care employees available to address customer questions and concerns.¹⁷²⁶

Ongoing and future engagement activities include a Customer Flipbook that employees can use to explain the undergrounding process to customers to help them understand project benefits and construction expectations.¹⁷²⁷ In addition, A-frame and large-construction signage in undergrounding areas in high traffic areas will be utilized to raise project awareness and guide community members to additional information.¹⁷²⁸ In the future, PG&E will deploy: (1) Customer Answer Centers in areas with high amounts of undergrounding work to raise awareness and answer questions, (2) Onsite Local Customer Experience Support, including Local Customer Experience Representatives during the initial phases of construction, (3) Informational postcards including project timelines and specific and (4) Local Government/Nextdoor/Blog Posts ahead of work occurring in a specific jurisdiction (City/County/Tribe).¹⁷²⁹

¹⁷²⁴ PG&E-17, p. 4.3-22, lines 6-8.

¹⁷²⁵ PG&E-17, p. 4.3-22, lines 8-10.

¹⁷²⁶ PG&E-17, p. 4.3-22, lines 10-12.

¹⁷²⁷ PG&E-17, p. 4.3-22, lines 12-15.

¹⁷²⁸ PG&E-17, p. 4.3-22, lines 15-18.

¹⁷²⁹ PG&E-17, p. 4.3-22, lines 18-24.

PG&E is also leveraging its ongoing Community Wildfire Safety Program Webinars to share undergrounding content.¹⁷³⁰ PG&E has hosted two in-person town halls in Lake County to share info and answer questions regarding underground work in the area.¹⁷³¹ PG&E will host similar events as undergrounding activities move into other communities. Finally, PG&E is working to bring in a new augmented virtual reality tool that will be used by land agents as they negotiate easement acquisitions with property owners; this technology will enhance the communication with property owners, particularly when design changes take place.¹⁷³²

In short, any general criticisms about a lack of program details being provided by PG&E are unwarranted. PG&E has active plans in place to keep stakeholders and other interested parties informed about our undergrounding plans and the progress being made.

4.3.1.6 Telecommunication Intervenor's Objections Are Without Merit

Both AT&T and Comcast object to PG&E's 10,000 mile undergrounding program on the entirely self-interested ground that the program will impact their operations by increasing their costs if they are required to participate in joint trench projects. The Commission should be skeptical of these objections given that telecommunication providers are under no obligation to participate in PG&E's program, and that their rights and obligations for the poles they share with PG&E are governed by separate contractual instruments. In the subsections below, we explain: (1) the telecommunications companies are under no obligation to participate in PG&E's undergrounding program; (2) there are existing contractual procedures that address the telecommunication companies' concerns; (3) PG&E is coordinating with telecommunications companies; and (4) undergrounding location information will be provided when available.

¹⁷³⁰ PG&E-17, p. 4.3-22, lines 25-26.

¹⁷³¹ PG&E-17, p. 4.3-22, lines 26-28.

¹⁷³² PG&E-17, p. 4.3-22, lines 30-34.

4.3.1.6.1 The Telecommunication Companies Are Under No Obligation To Participate In PG&E's Undergrounding Program

AT&T and Comcast both admit that they have no obligation to underground their existing overhead communication lines as a result of PG&E's undergrounding program.¹⁷³³ Moreover, PG&E's undergrounding testimony and proposals do not ask the Commission to require AT&T, Comcast, or any other party, to participate in PG&E's undergrounding program. Both parties, however, suggest the possibility that governmental entities may exert pressure against them to join undergrounding with PG&E,¹⁷³⁴ but admit that whether they ultimately elect to participate in an undergrounding segment is entirely their choice.¹⁷³⁵ They also do not explain how this hypothetical pressure is any different than what conceivably already occurs across their service territories in California when a governmental entity seeks to require utility undergrounding.

PG&E does not make this point to minimize the business issues that AT&T and Comcast may face in communities where PG&E is undergrounding lines. PG&E's point is that these business issues have no bearing on the reasonableness of PG&E's undergrounding program because the program itself does not directly impact AT&T's and Comcast's business decisions. The extent to which AT&T and Comcast are impacted is up to them in their dealings with government entities in the event these issues arise.

4.3.1.6.2 There Are Existing, Well-Established Contractual Procedures That Govern PG&E's, AT&T's, And Comcast's Respective Legal Rights

AT&T's and Comcast's legal rights in relation to electric distribution poles that may be undergrounded are governed by legal agreements with PG&E. AT&T California and PG&E are members of the Northern California Joint Pole Association (NCJPA).¹⁷³⁶ The NCJPA is an

¹⁷³³ AT&T-03, p. 3, lines 11-12. Tr. Vol. 13, 2520:19-24, Comcast/Votaw.

¹⁷³⁴ AT&T-03, p. 3, lines 12-13; Comcast-01, p. 11, lines 13-23.

¹⁷³⁵ Tr. Vol. 13, 2585:18-22, AT&T/Iqbal; 2522:23-28, Comcast/Votaw.

¹⁷³⁶ PG&E-17, p. 4.3-69, lines 27-28.

association of pole owners governing the ownership, maintenance and use of jointly owned poles.¹⁷³⁷ The NCPJA has adopted detailed rules and procedures that govern a range of transactions between its members, including the allocation of costs between the joint owners of a pole for general maintenance, pole replacements, and removals.¹⁷³⁸ Among other things, the NCJPA procedures specify the manner in which a joint owner may surrender its undivided joint interest in a pole, known as Relinquishment.¹⁷³⁹ Relinquishment of a member's joint interest in a pole under the NCJPA procedures is the well-establish practice between the NCJPA members.¹⁷⁴⁰ For future undergrounding work, PG&E anticipates that it will relinquish its joint interest in poles, resulting in title to the poles transferring to the telecommunications member. AT&T California, PG&E, and all other NCJPA members regularly utilize these relinquishment procedures in the ordinary course of business. Any disputes regarding the NCPJA would be resolved by a Superior Court, rather than the Commission.¹⁷⁴¹ Thus, the Commission does not need to address any issues regarding the NCJPA in its decision in this GRC.

Comcast's legal situation is different. Comcast has attached some of its facilities within the communication-space on jointly-owned poles (such as a PG&E-AT&T joint poles) under a license issued by and administered by the telecommunication member – AT&T.¹⁷⁴² As discussed above, the telecommunication member may decline to participate in PG&E's undergrounding program. In this case, the telecommunication member would continue to own and operate the pole as a solely-owned pole, and the overhead license issued to Comcast will

¹⁷³⁷ PG&E-17, p. 4.3-69, line 28 to p. 4.3-70, line 2.

¹⁷³⁸ PG&E-17, p. 4.3-70, lines 2-5, PG&E-60.

¹⁷³⁹ PG&E-60, p. 5-1 to p. 5-4, Section 5.

¹⁷⁴⁰ PG&E-17, p. 4.3-70, lines 7-9.

¹⁷⁴¹ PG&E-17, p. 4.3-70, lines 9-11.

¹⁷⁴² PG&E-17, p. 4.3-70, lines 12-14.

continue in full force and effect.¹⁷⁴³ Comcast also has attached some of their facilities on PG&E solely-owned poles, under revocable overhead licenses to Comcast.¹⁷⁴⁴ These overhead licenses are expressly conditioned upon the Commission's General Order 69-C, which requires the joint use of PG&E's facilities to terminate if in the best interests of PG&E's core customers.¹⁷⁴⁵ PG&E's overhead licenses provide that upon termination, the licensee will relinquish its use of the pole and remove its communication attachments.¹⁷⁴⁶ Therefore, Comcast has always accepted the use of PG&E's poles as conditional and subject to PG&E's business decision to convert its overhead facilities to an underground location.

Nonetheless, Comcast asks the Commission to ignore these license provisions and either: (1) require PG&E to leave poles in place in order to allow Comcast and other attachers to maintain its attachments and pay PG&E the annual attachment rental fees in effect between the parties, or (2) require PG&E to pay costs associated with undergrounding the facilities of existing attachers like Comcast.¹⁷⁴⁷ As a licensee of a revocable license, the requests are remarkably audacious regarding Comcast's legal obligations, and the Commission should grant neither request. Comcast's legal rights are governed by the terms of the revocable licenses it agreed to. Had Comcast wanted the ability to stay on a pole for an indefinite period, it could have negotiated different licensing terms (at a higher price) or installed its own poles. Comcast made a business decision not to, and it should have to bear the consequences of that decision. PG&E is not responsible for Comcast's business decisions, and the Commission should not

¹⁷⁴³ PG&E-17, p. 4.3-70, lines 16-19.

¹⁷⁴⁴ PG&E-17, p. 4.3-70, lines 19-21; PG&E-62 (containing exemplars of licenses).

¹⁷⁴⁵ PG&E-62, Overhead Facilities License Agreement and Amendments, pp. 3-4, Article II, par. 2.1(b).

¹⁷⁴⁶ PG&E-17, p. 4.3-70, lines 21-23.

¹⁷⁴⁷ Comcast-01, p. 12, lines 5-12.

impose a duty upon PG&E to maintain poles or pay for another utility's costs, in what would amount to a subsidy solely for the benefit of Comcast and other attachers.

4.3.1.6.3 PG&E Is Coordinating With Telecommunication Companies In Connection With PG&E's Undergrounding Program

PG&E is coordinating with AT&T and Comcast, when possible, as we plan and implement undergrounding projects and will provide written notice of the specific locations where the undergrounding work will be performed. This will provide AT&T and Comcast with the opportunity to voluntarily participate in converting their overhead communications facilities underground in a joint trench, or not. Should AT&T or Comcast elect to participate in a specific joint trench project, the joint trench would be designed for the co-location of the electric and communication facilities. In this circumstance, the existing overhead pole line facilities would be fully removed following the undergrounding work, provided that other pole tenants, where applicable, also agree to move their cable underground.

AT&T and Comcast may determine that a specific undergrounding segment does not fit their respective capital plans or other business needs and choose to retain their existing overhead communication facilities. Should AT&T or Comcast decline to participate in any underground segment, PG&E would follow the existing contractual procedures described above and would expect AT&T and Comcast to do the same. Although AT&T and Comcast speculate about the potential costs they may incur if they fully participate in PG&E's undergrounding program, they admit they have no obligation to participate in any undergrounding work.

4.3.1.6.4 Undergrounding Location Information Will Be Provided When Available

Comcast argues that PG&E should be required to submit a revised plan that includes specific information about the areas in which PG&E plans to underground its facilities for at least the next five years.¹⁷⁴⁸ There is no compelling regulatory reason for PG&E to provide the

¹⁷⁴⁸ Comcast-01, p. 12, lines 20-23.

specific location information in a revised plan in this GRC. The Commission is reviewing PG&E's funding request for undergrounding, not the specific undergrounding location plans.

In addition, undergrounding plans will necessarily evolve over the life of the program as PG&E integrates lessons learned, incorporates new technologies, updates its risk modeling, and addresses stakeholder concerns. It will be both reasonable and necessary to refine and continually update the program over time.

In any event, information regarding general project locations in the rate-case period is already available. On July 26, 2022, PG&E provided Energy Safety a list of approximately 3,100 risk, feasibility ranked miles that make up the majority of the first tranche of miles that PG&E will further evaluate for including in the undergrounding program.¹⁷⁴⁹ As indicated above, PG&E will provide written notice of the specific locations where the undergrounding work will be performed once those determinations have been made.

4.3.1.7 Other Issues

Parties raise miscellaneous issues regarding PG&E's undergrounding program. In the subsections below, PG&E addresses: (1) Cal Advocates' recommendations based on PG&E's original June 30, 2021 testimony; (2) AARP's proposal to delay a decision on the undergrounding program; (3) Cal Advocates' recommendations regarding undergrounding reporting requirements; and (4) various other TURN recommendations not previously addressed.

4.3.1.7.1 Cal Advocates' Recommendations Are Inapposite And Should Be Disregarded

Cal Advocates based its recommendations regarding PG&E's undergrounding program on PG&E's original June 30, 2021 testimony which did not contain the 10,000 mile undergrounding program and was superseded by PG&E's February 25, 2022 testimony.¹⁷⁵⁰ Cal Advocates claims it had insufficient time to review the revised capital expenditures forecast for

¹⁷⁴⁹ PG&E-17, p. 4.3-15, lines 19-22.

¹⁷⁵⁰ CALPA-07, p. 12, lines 15 to p. 13, line 1.

the 10,000 mile undergrounding program in PG&E's February 25, 2022 testimony before submitting its own testimony on June 13, 2022. Cal Advocates accepts the system hardening forecast (for both undergrounding and overhead) for 2022 and 2023 that PG&E presented in its superseded June 30, 2021 testimony, excluding forecasts for the Community Rebuild Program. When those accepted funding levels are considered in relation to PG&E's February 25, 2022 submittal, however, Cal Advocates' recommendations would reduce PG&E's 2023 system hardening forecast by \$1.05 billion. Cal Advocates does not address PG&E's 2024-2026 undergrounding forecast.¹⁷⁵¹

Cal Advocates' failure to review and respond to PG&E's February 25, 2022 testimony and updated forecast over the three and a half month period before Cal Advocates' own testimony was due is disappointing. The Assigned ALJs extended the procedural schedule for more than three months to allow intervenors sufficient time to review PG&E's updated undergrounding forecast, conduct discovery, and submit testimony.¹⁷⁵² Other intervenors were able to use this time and provide recommendations with respect to PG&E's updated forecast; only Cal Advocates submitted testimony based on a superseded forecast. Because Cal Advocates analyzed PG&E's superseded June 2021 forecast, there are no specific issues raised by Cal Advocates for PG&E to address in this brief. Instead, PG&E can only generally respond to Cal Advocates' overall proposed funding levels for 2022 and 2023 based on the superseded proposal and forecast. Cal Advocates' recommendation is inapplicable to PG&E's present request and should be disregarded.

¹⁷⁵¹ PG&E-17, p. 4.3-11, lines 7-15.

¹⁷⁵² *E-Mail Ruling Addressing Pending Motions & Request to Modify Schedule and Adopting Revised Schedule* (Apr. 12, 2022).

4.3.1.7.2 Postponing A Decision Is Unnecessary And Fails To Address Increasing Wildfire Risks

AARP criticizes PG&E's plan to underground 10,000 miles of electric lines as a wildfire risk mitigation strategy and recommends that the Commission postpone a decision on PG&E's undergrounding plan to allow further evaluation.¹⁷⁵³ The Commission should reject this recommendation as unnecessary.

AARP does not specify what length of a postponement would be appropriate and why the deliberative multi-month process provided in this GRC is insufficient. PG&E has submitted ample evidence supporting its 10,000 mile undergrounding proposal. PG&E also provided detailed information about its undergrounding program in its 2022 WMP. Intervenors have had an opportunity to review the proposal, conduct discovery, and submit testimony and other evidence to support their positions. The Commission has a sufficient evidentiary record (consisting of PG&E's proposal and intervenors' responses) upon which to reach an informed, reasoned decision. There is no compelling reason to delay a decision.

In addition, postponing a decision on PG&E's undergrounding program for an indefinite period would unnecessarily disrupt PG&E's ability to plan for undergrounding as well as its other suite of wildfire mitigation efforts. This disruption, in turn, would have detrimental consequences by delaying efforts to implement a coordinated wildfire risk mitigation strategy. Such consequences should be avoided, particularly at a time when California, along with other western states, continues to experience an increase in wildfire risk and a longer wildfire season. In 2020 and 2021, for example, PG&E's service area was under extreme and severe drought conditions, with California experiencing its 5th and 2nd driest water years, respectively, in the last century.¹⁷⁵⁴ In addition, on non-Red Flag Warning (RFW) days in 2021, there was a more than 500 percent increase in acreage burned, as compared to the average acreage in the prior four

¹⁷⁵³ AARP-01, p. 78, line 18 to p. 79, line 8.

¹⁷⁵⁴ PG&E-04, p. 4.3-7, line 29 to p. 4.3-8, line 3.

years.¹⁷⁵⁵ Simply put, these facts show that this is not a time for delay and inaction, the consequences of which tip the balance in favor of bold initiatives such as PG&E’s 10,000 mile underground program.

4.3.1.7.3 Cal Advocates’ Recommendations Regarding Reporting Requirements Are Unnecessary

Cal Advocates suggests various tracking/monitoring recommendations, including that the Commission require PG&E to: (1) submit annual Tier 3 advice letters for SPD to determine that PG&E is on track with its progress towards its WMP and GRC System Hardening forecasts and is targeting of the highest risk miles; (2) submit a detailed analysis of alternatives to undergrounding, such as SCE’s evaluation of Rapid Earth Fault Current Limiter technology; (3) collaborate with Energy Safety and conduct enforcement actions for any substantial non-compliance of approved WMP and GRC work; (4) provide shareholder funding for 2021-2023 system hardening work that was not completed in “the highest risk miles” per the 2021 WMP if it does not complete the work within PG&E’s stated period of three years; and (5) be subject to a fine under Public Utilities Code § 451.3 if the findings in the Performance Audit of PG&E WMP Expenditures Final Report by Crowe LLP are accurate.¹⁷⁵⁶ Cal Advocates also recommends that the Commission require PG&E to provide calculations showing how it determines the forecasted target miles before approving its System Hardening program.¹⁷⁵⁷

Cal Advocates’ recommendations regarding monitoring/reporting requirements are beyond the scope of this proceeding or duplicative of other existing requirements. The first recommendation to require PG&E to track its undergrounding progress against WMP and GRC commitments,¹⁷⁵⁸ is beyond the scope of this proceeding. To the extent it is deemed as within

¹⁷⁵⁵ PG&E-17, p. 4.3-21, lines 17-20.

¹⁷⁵⁶ CALPA-17, p. 12, lines 1-24.

¹⁷⁵⁷ CALPA-17, p. 6, lines 3-6.

¹⁷⁵⁸ CALPA-17, p. 4, line 29 to p. 5, line 10.

the scope of this proceeding, the requirement is also unnecessarily duplicative of existing requirements in that PG&E's undergrounding progress against GRC-approved units and costs will be included in the annual Risk Spending Accountability Report (RSAR). No further GRC compliance requirement should be required. PG&E also opposes the second recommendation that would require PG&E to submit a detailed analysis of alternatives to undergrounding. Analysis of alternative wildfire mitigations are already included in the WMP.¹⁷⁵⁹

The third,¹⁷⁶⁰ fourth¹⁷⁶¹ and fifth¹⁷⁶² recommendations regarding enforcement actions, shareholder funding, and imposition of fines are also beyond the scope of the GRC. Moreover, the recommendations, which speculate about the possible non-compliance with work plans, request Commission actions on assertions that are not supported by the evidentiary record.

Finally, PG&E opposes Cal Advocates' recommendation to require PG&E to provide calculations showing how it determines the forecasted target miles before approving its System Hardening program.¹⁷⁶³ PG&E provided information to Energy Safety on July 26, 2022 in response to WMP RN-PG&E-22-04 related to the selection of underground miles.¹⁷⁶⁴ PG&E's response to RN-PG&E-22-04 included the risk ranking for the first tranche of miles for 2024 through 2026.¹⁷⁶⁵ The response to RN-PG&E-22-04 satisfies this recommendation and PG&E should not be required to provide additional information.

¹⁷⁵⁹ See OEIS, 2023-2025 Draft Wildfire Mitigation Plan Technical Guidelines (Sept. 19, 2022), pp. 75-79, Section 7.1.4, "Mitigation Selection Process," which describes the process for identifying and evaluating alternative wildfire mitigations in the 2023 WMP for the period 2023-2025.

¹⁷⁶⁰ CALPA-17, p. 12, lines 13-16.

¹⁷⁶¹ CALPA-17, p. 12, lines 17-20.

¹⁷⁶² CALPA-17, p. 12, lines 21-24

¹⁷⁶³ CALPA-17, p. 6, lines 3-6.

¹⁷⁶⁴ PG&E-17, p. 4.3-61, lines 1-14.

¹⁷⁶⁵ PG&E-17, p. 4.3-61, lines 15-18.

4.3.1.7.4 TURN's Non-Financial Recommendations Are Unnecessary Or Counterproductive

TURN makes three non-financial recommendations related to undergrounding: (1) the Commission must ensure system hardening work is targeted to the highest risk miles; (2) maximum unit costs of undergrounding should be adopted to ensure PG&E is held to a reasonable forecast; and (3) any large-scale undergrounding program approved by the Commission should leverage outside funds and be financed at the cost of debt.¹⁷⁶⁶ Each of these proposals is addressed below.

First, in its 2022 WMP, PG&E committed to target 80 percent of the system hardening work in highest risk miles.¹⁷⁶⁷ The Commission should reject TURN's proposal as duplicative of the reporting that will occur in the WMP process.

Second, TURN's proposal to set a cap of \$2.98 million per underground mile on a weighted average basis over the GRC period is unwarranted.¹⁷⁶⁸ While PG&E is confident that it can achieve the unit cost targets that it proposed for this GRC period, a two-way balancing account, as proposed by PG&E, would provide some ability to seek additional cost recovery if PG&E's costs exceeded a mandated cost cap. However, TURN recommends that the WMBA be converted from a two-way to a one-way balancing account and seeks to impose a cost cap, claiming that PG&E should be able to forecast wildfire mitigation costs at a sufficient level of accuracy that the protection of a two-way balancing account is no longer needed.¹⁷⁶⁹ PG&E disagrees with TURN's proposal and believes that a two-way balancing account continues to be

¹⁷⁶⁶ TURN-11, p. 46, line 1 to. p. 48, line 22.

¹⁷⁶⁷ PG&E-17, p. 4.3-62, lines 8-11; PG&E's 2022 Wildfire Mitigation Plan, R.18-10-007 (Feb. 25, 2022), p. 545.

¹⁷⁶⁸ TURN-11, p. 47, lines 23-24.

¹⁷⁶⁹ TURN-13, p. 23, lines 10-14.

an appropriate accounting mechanism for the undergrounding program.¹⁷⁷⁰ While PG&E believes its forecast unit costs are sound for the reasons explained in Section 4.3.1.4, the program is still developing and there are uncertainties. The two-way balancing account is fair because it protects customers if projects are not completed but also gives PG&E the opportunity to seek recovery if costs exceed the forecast due to unforeseen circumstances or other valid reasons. If actual expenditures are lower than forecast, unused funds will be returned to ratepayers.¹⁷⁷¹ If expenditures are higher than forecast, PG&E will have an opportunity to request recovery by demonstrating to the Commission in a public forum that the costs incurred were reasonable and should be recovered.¹⁷⁷² Imposing a cap and converting the WMBA to a one-way balancing account unfairly places all the risk on PG&E shareholders if factors outside of PG&E's control disrupt the undergrounding program. Section 4.24 below addresses the appropriateness of a two-way balancing account in further detail.

Third, PG&E opposes TURN's proposal that PG&E leverage outside funds and finance the program at the cost of debt. PG&E explains its opposition in detail PG&E-14, Chapter 3.¹⁷⁷³ Briefly summarized here, the proposal would require PG&E to dangerously leverage itself from a financial perspective and take on massive amounts of debt. The amount of debt that would be required would harm the utility's financial health and increase the cost of capital, which would eventually increase customer costs. TURN's recommendation is antithetical to PG&E's need to improve its financial health, and the Commission's directive to reduce PG&E's

¹⁷⁷⁰ The WMBA should remain a two-way balancing account covering not only the undergrounding program but all the wildfire mitigation programs PG&E is forecasting. PG&E discusses the WMBA in PG&E-04, p. 4-22, line 20 to p. 4-24, line 27. Section 4.24 of this brief also discusses the reasons why the Commission should approve the continuation of a two-way balancing account.

¹⁷⁷¹ PG&E-17, p. 4.3-63, lines 28-29.

¹⁷⁷² PG&E-17, p. 4.3-63, line 29 to p. 4.3-64, line 5.

¹⁷⁷³ PG&E-14, p. 3-12, line 24 to p. 3-14, line 2.

level of debt.¹⁷⁷⁴ With that said, PG&E agrees that if PG&E uses outside funds for undergrounding projects for which it has an approved revenue requirement, PG&E will credit them to the WMBA.

4.3.2 Overhead System Hardening

Although PG&E is pivoting towards undergrounding for its system hardening in high fire risk areas, currently the most frequently-used method for system hardening is overhead hardening.¹⁷⁷⁵ After analyzing projected performance of overhead hardened facilities on more than 4,600 outage types, PG&E projects that overhead system hardening will reduce 62 percent of the distribution overhead asset ignitions caused by equipment failures or external contact/strikes with energized lines, such as vegetation tree strikes.¹⁷⁷⁶ Overhead system hardening achieves risk reduction through the following foundational activities: (1) primary and secondary covered conductor replacement; (2) pole replacements; (3) replacement of non-exempt equipment; (4) replacement of overhead distribution line transformers; (5) framing and animal protection upgrades; and (6) vegetation clearing. PG&E discusses overhead system hardening in further detail in its opening testimony.¹⁷⁷⁷ As PG&E shifts its system hardening program to focus more on undergrounding, PG&E's overhead hardening goals and strategy have also shifted. Under PG&E's overall system hardening forecast, overhead hardening mileage will decrease from roughly 180 miles in 2021 to roughly 50 miles a year by 2026.¹⁷⁷⁸

PG&E's capital forecasts and intervenors' recommended adjustments for Overhead System Hardening from 2020-2026 are summarized below.

¹⁷⁷⁴ "Consistent with PG&E's plan we expect PG&E to expeditiously pay down Temporary Utility debt over the projected five-year period and regain a closer alignment between aggregate utility debt and the amount of recoverable utility debt." D.20-05-053, p. 84.

¹⁷⁷⁵ PG&E-17, p. 4.3-44, lines 13-16.

¹⁷⁷⁶ PG&E-17, p. 4.3-47, lines 2-5.

¹⁷⁷⁷ PG&E-17, p. 4.3-35, lines 22-27.

¹⁷⁷⁸ PG&E-04, p. 4.3-47, lines 12-16.

**TABLE 4-2:
OVERHEAD SYSTEM HARDENING - PG&E'S CAPITAL FORECAST^(a) AND PARTIES
RECOMMENDED (REDUCTIONS)/INCREASES (\$000s)^(b)**

Party	2020 Rec.	2021	2022	2023	2024	2025	2026
PG&E ^(c)		\$288,000	\$366,000	\$265,377	\$81,507	\$83,918	\$86,402
Cal Advocates		\$(167,572)	\$0	\$0			
TURN				\$9,823	\$286,364	\$293,886	\$301,603
AARP				\$55,445	\$230,257	\$228,449	\$226,572

(a) PG&E-04, p. 4.3-51, Table 4.3-11, line 1.

(b) PGE-17, WP 4.3-1. Cal Advocates, TURN, and AARP's recommendations are presented as recommended funding levels as opposed to recommended reductions. PG&E has calculated the recommended reduction by subtracting Parties' recommended funding level for system hardening overhead from PG&E's forecast.

(c) PG&E does not segregate 2020 recorded costs into the individual system hardening components.

Cal Advocates used PG&E's 2021 recorded capital expenditures for overhead system hardening as its recommended funding level.¹⁷⁷⁹ Cal Advocates further states that it accepts PG&E's new updated 2022 and 2023 capital expenditure forecasts of \$366.0 million in 2022 and \$265.4 million in 2023, with zero adjustments, because the updated forecasts are significantly lower than PG&E's original 2022 and 2023 forecasts and the unit costs align well with recent recorded costs.¹⁷⁸⁰

TURN recommends increased deployment of the overhead program coupled with reduced deployment of undergrounding, which would result in the installation of 1,800 miles of covered conductor over the GRC period. This proposal would result in an increase to PG&E's forecast each year from 2023-2026 by the amount shown above, with a total increase to PG&E's forecast of \$974.7 million over this period.¹⁷⁸¹ TURN's forecast recommendation is based on a unit cost of approximately \$800,000 per mile.¹⁷⁸²

¹⁷⁷⁹ CALPA-07, p. 14, lines 20-21.

¹⁷⁸⁰ CALPA-07, p. 15, lines 5-7. The "new, updated" forecasts Cal Advocates refers to is PG&E's February 25, 2022 forecast whereas the "original" forecasts refer to PG&E's June 30, 2021 forecast.

¹⁷⁸¹ TURN-11, p. 45, lines 4-6 and Table 12.

¹⁷⁸² TURN-11, p. 21, lines 2-5.

AARP recommends that the Commission authorize half of PG&E's originally-requested capital for overhead line hardening.¹⁷⁸³ This recommendation would allow PG&E to proceed with overhead line hardening for the highest-risk areas as prioritized by the California State Auditor's report,¹⁷⁸⁴ while preserving opportunities to deploy remote grid and LEIP (Line Elimination Incentive Program) where those are more cost-effective than overhead line hardening.¹⁷⁸⁵ This proposal would result in an increase to PG&E's forecast each year from 2023-2026 by the amount shown above, with a total increase to PG&E's forecast of \$740.7 million over this period.

In the sections below, PG&E responds to the parties' various recommendations and contentions. Section 4.3.2.1 briefly addresses Cal Advocates' recommendations. Section 4.3.2.2 refutes TURN's recommendations, identifying several flaws and problems with TURN's proposal for an overhead-focused strategy that ultimately fails to sufficiently address wildfire risk reduction in comparison to PG&E's underground-focused strategy. Section 4.3.2.3 refutes AARP's recommendations, which similarly fail to address wildfire risk in a timely manner.

¹⁷⁸³ AARP-01, p. 76, lines 8-12.

¹⁷⁸⁴ The March 2022 California State Auditor's Report includes a map (Figure 4) that it describes as the fire threat map published by the CPUC that designates significant portions of the State to be at an elevated extreme risk of fire and which the Auditor's report refers to collectively as *high fire-threat areas*. (California Acting State Auditor, Electrical System Safety, California's Oversight of the Efforts by Investor-Owned Utilities to Mitigate the Risk of Wildfires Needs Improvement, Report 2021-117 (Mar. 24, 2022), Figure 4, at <https://auditor.ca.gov/reports/2021-117/index.html#chapter1> > as of October 31, 2022.) PG&E assumes that Figure 4 in the March 2022 California State Auditor's Report is a map of the High Fire Threat Districts. PG&E's System Hardening Overhead Program already targets the highest risk miles and frequently impacted PSPS areas in the HFTD and buffer zones immediately adjacent to HFTD areas. PG&E-04, p. 4.3-46, line 23 to p. 4.3-47, line 10.

¹⁷⁸⁵ AARP-01, p. 76, line 10 to p. 77, Table, lines 1-2. Note, the table shows AARP's recommended reductions as positive numbers and recommended funding levels as negative numbers.

4.3.2.1 The Commission Should Adopt Cal Advocates' Recommendation For 2021-2023 And Adopt PG&E's Forecast For 2024-2026

PG&E agrees with Cal Advocates' recommendations for 2021-2023. Cal Advocates, however, did not address PG&E's 2024-2026 forecast of \$251.8 million.¹⁷⁸⁶ For the reasons described in PG&E's February 25, 2022 testimony and further addressed in this brief, PG&E's integrated system hardening program, which focuses on undergrounding but provides for overhead hardening in certain narrower applications (170 miles in 2023 and 50 miles from 2024-2026)¹⁷⁸⁷ is the right approach for mitigating wildfire risk. PG&E's capital forecasts for the integrated program are reasonable.

4.3.2.2 The Commission Should Reject TURN's Recommendations As Unsound

In support of its proposal to increase overhead hardening miles and reduce undergrounding miles, TURN asserts the following: (1) system hardening overhead work should not include replacement of useful assets that do not pose significant ignition risk and are not necessary to replace for the installation of covered conductor;¹⁷⁸⁸ (2) installation of covered conductor is a more cost-effective approach to mitigating ignition risk, as indicated by a higher RSE score;¹⁷⁸⁹ (3) TURN's recommendation is more cost-effective at the individual tranche level;¹⁷⁹⁰ and (4) TURN's proposed scope of deployment of covered conductor addresses the top 60 percent of risk over the next ten years based on a combination of undergrounding and overhead hardening.¹⁷⁹¹ PG&E addresses each issue below.

¹⁷⁸⁶ PG&E-17, p. 4.3-36, lines 15-16.

¹⁷⁸⁷ PG&E-04, p. 4.3-51, Table 4.3-11, line 2.

¹⁷⁸⁸ TURN-11, p. 24, lines 11-13.

¹⁷⁸⁹ TURN-11, p. 26, lines 1-3.

¹⁷⁹⁰ TURN-11, p. 26, line 12 and p. 27, Figure 9.

¹⁷⁹¹ TURN-11, p. 27, lines 6-10 and p. 28, Figure 10.

4.3.2.2.1 PG&E's Approach Of Replacing All Components Reflects Sound Utility Practices

PG&E disagrees with TURN's assertion¹⁷⁹² that it is unnecessary to replace certain assets that do not pose a significant ignition risk as part of the installation of covered conductor for the following reasons. First, it is reasonable to replace all the components of the covered conductor system at the same time because installing different components at different times carries the risk of requiring a re-sizing of the pole and requiring a second pole replacement or other redundant component replacements for compatibility.¹⁷⁹³ Second, installing different components at different times requires PG&E to mobilize multiple crews to the same site, which would increase costs.¹⁷⁹⁴ Third, to the extent there is non-exempt equipment that is currently in place, it would violate PG&E's standards to re-install non-exempt equipment.¹⁷⁹⁵ PG&E's approach ultimately saves time and costs, while ensuring safe and reliable service is maintained. It also reflects sound utility practice, as the replacement of all components at the same time better ensures overall reliability and system performance. TURN's approach is unsound and could lead to unforeseen problems, such as having to replace a pole or other components twice as noted above.

4.3.2.2.2 TURN's RSE Calculation For Covered Conductor Is Defective

TURN artificially increased the RSE score for covered conductor/overhead system hardening by eliminating normal asset replacements its witness, who has no construction or utility asset management experience, opined were unnecessary.¹⁷⁹⁶ PG&E's Electric Operations risk witness addressed this issue in Exhibit PG&E-04, Chapter 3, Section C.3. Moreover, as explained in Section 4.2.2 above, TURN's alternate RSE calculation for overhead

¹⁷⁹² TURN-11, p. 24, lines 11-13.

¹⁷⁹³ PG&E-17, p. 4.3-37, lines 17-20.

¹⁷⁹⁴ PG&E-17, p. 4.3-37, lines 20-22.

¹⁷⁹⁵ PG&E-17, p. 4.3-37, lines 22-24.

¹⁷⁹⁶ TURN-11, p. 26, lines 1-6 and Figure 8.

system hardening is fundamentally flawed, given that it is unreasonable to not replace overhead components when performing overhead hardening work. PG&E's analysis shows that the RSE for undergrounding becomes higher than the RSE for overhead system hardening as the pace of PG&E's undergrounding program increases.¹⁷⁹⁷ For example, undergrounding provides permanent, near-total risk reduction and, unlike overhead system hardening, will significantly reduce the need for other costly mitigation activities.

4.3.2.2.3 TURN's Proposal Does Not Sufficiently Address Wildfire Risk

TURN asserts that its proposal for overhead and underground hardening addresses the top 60 percent of risk over the next ten years.¹⁷⁹⁸ TURN's risk-reduction calculations are defective.

As explained in Section 4.2.2, PG&E calculates that TURN's proposal would address only about 40 percent of the risk over the next 10 years. Because TURN's proposal does not provide sufficient risk reduction, nor address risk quickly enough, PG&E strongly opposes TURN's proposed 1,800 miles of overhead miles and 200 miles of undergrounding for this rate case period.¹⁷⁹⁹ PG&E has made a fundamental shift in its system hardening work and is using undergrounding as the preferred option after line removal or remote grid installation, where appropriate. While undergrounding is the preferred mitigation for its risk reduction and other benefits, PG&E will also use other mitigations. In some instances, overhead system hardening may be a more appropriate mitigation method because of environmental factors in certain areas. For example, in areas with more grass and fewer strike potential trees, PG&E may determine that overhead hardening work is faster, and more cost effective, than undergrounding.¹⁸⁰⁰ In addition, some remote or inaccessible areas may be cost prohibitive to underground.¹⁸⁰¹ These

¹⁷⁹⁷ PG&E-04, p. 3-6, Table 3-1.

¹⁷⁹⁸ TURN-11, p. 27, lines 6-10 and p. 28, Figure 10.

¹⁷⁹⁹ TURN-11, p. 21, lines 2-3.

¹⁸⁰⁰ PG&E-17, p. 4.3-38, lines 22-24.

¹⁸⁰¹ PG&E-17, p. 4.3-38, lines 24-25.

areas may be better suited for a remote grid solution, especially if limited customers are involved.¹⁸⁰² The balance of undergrounding and overhead miles PG&E is forecasting to complete during this rate case will provide the most risk reduction in the HFTD areas.

PG&E also disagrees with TURN's assumptions regarding system hardening overhead unit costs. TURN's recommended unit cost fails to consider certain components of PG&E's system hardening overhead program that need to be included in the build-up of a reasonable unit cost. TURN starts its discussion about PG&E's unit costs for overhead system hardening by comparing PG&E's forecast unit costs with SCE's recorded covered conductor deployment costs: approximately \$1.6 million per mile for PG&E versus \$629,000 per mile for SCE in 2021.¹⁸⁰³ However, TURN's analysis fails to address three key factors that drive the difference in cost between SCE and PG&E: vegetation management; pole replacement; and equipment upgrades.

First, vegetation clearing in support of a new overhead line can significantly increase PG&E's costs for overhead system hardening projects. Both the increased height of the poles, the widened cross-arms, and the increased sag of the line (all due to the weight of the covered conductor) can vary the cost considerably. This cost alone can add between \$50,000 to \$400,000 per mile depending on the terrain and the location of the line. The rural, more heavily-wooded nature of HFTDs in PG&E's service territory where the work is completed drives the need for additional vegetation clearing.¹⁸⁰⁴ SCE reports it has not generally observed significant vegetation management or access road rehabilitation costs across its installations in its less

¹⁸⁰² PG&E-04, p. 4.3-7, lines 8-19.

¹⁸⁰³ TURN-11, p. 21, lines 9-12.

¹⁸⁰⁴ SDG&E's 2022 Wildfire Mitigation Plan Update OEIS Docket #2022 WMP (Feb. 11, 2022), Attachment H: Joint IOU Response to Action Statement-Covered Conductor, p. 49, <<https://www.sdge.com/sites/default/files/regulatory/SDG%26E%202022%20WMP%20Update%2002-11-2022.pdf>> (as of Oct. 26, 2022).

heavily-wooded territory.¹⁸⁰⁵ This critical cost-driver difference is not acknowledged by TURN.

Second, in connection with pole replacement costs, PG&E replaces nearly 100 percent of its poles due to the additional weight/sag of the new covered conductor.¹⁸⁰⁶ SCE only replaces, on average, 10 to 12 poles which represents approximately 34 percent to 41 percent of the average number of poles per circuit mile.¹⁸⁰⁷

Third, the equipment upgrades PG&E completes during its overhead hardening work also increase PG&E's costs relative to SCE. PG&E incorporates numerous initiatives into a single hardening project. Non-exempt equipment and ignition-component replacements significantly adds to costs due to the material and labor installation costs of the new equipment.¹⁸⁰⁸ SCE generally is focused on covered conductor only and does not include other major equipment upgrades.¹⁸⁰⁹

In regard to the second and third cost-drivers discussed above, PG&E cannot speak to SCE's system, but PG&E's replacement of 100 percent of poles, non-exempt equipment, and ignition-components replacement is the prudent approach for PG&E's system as discussed in Section 4.3.2.2.1 above. What is for certain is that the Commission should not impose SCE's costs onto PG&E as suggested by TURN without fully understanding the technical reasons why there are cost differences.

Ignoring that SCE's and PG&E's system and technical requirements are different, TURN nevertheless proposes a unit cost of \$800,000 per circuit mile for overhead system hardening for

¹⁸⁰⁵ *Id.*, p. 48.

¹⁸⁰⁶ *Id.*, p. 49.

¹⁸⁰⁷ *Id.*, p. 48.

¹⁸⁰⁸ *Id.*, p. 49.

¹⁸⁰⁹ *Id.*, p. 48.

PG&E based on its flawed analysis of SCE's costs.¹⁸¹⁰ PG&E does not agree with TURN's proposed unit costs for the reasons discussed above – simply stated, the unit costs do not reflect PG&E's historical costs. PG&E's TY 2023 unit cost estimate of approximately \$1.56 million per circuit mile is a reasonable forecast, as it is based on PG&E's 2020 recorded costs of \$1.89 million per mile with certain adjustments.¹⁸¹¹ PG&E excluded costs for vegetation management because work planned in future years is likely to occur in areas with much less vegetation. PG&E further reduced the unit costs to address affordability concerns and then included an inflation adjustment.¹⁸¹²

4.3.2.3 AARP's Proposed Funding Adjustment To Allow For Half Of PG&E's Original Overhead Hardening Program Delays And Undermines The Risk Reductions

AARP proposes an adjustment based on its recommendation that the Commission postpone a decision on PG&E's undergrounding proposal and authorize half of the originally-requested capital for overhead line hardening.¹⁸¹³ AARP reasons that this recommendation would allow PG&E to proceed with overhead line hardening for the highest-risk areas while preserving opportunities to deploy remote grid and LEIP (Line Elimination Incentive Program) where those are more cost-effective than overhead line hardening.¹⁸¹⁴

PG&E agrees that overhead system hardening is an important part of PG&E's wildfire mitigation strategy, but PG&E's undergrounding program should proceed without delay as forecast in PG&E's February 25, 2022 GRC update, which emphasizes undergrounding with

¹⁸¹⁰ TURN-11, p. 22, lines 19-20.

¹⁸¹¹ PG&E-04, WP 4-28, line 18.

¹⁸¹² PG&E-17, PG&E's response to Data Request TURN_007-Q06, dated 9/16/21, pp. App A-69 to App A-70.

¹⁸¹³ AARP-01, p. 76, lines 8-12.

¹⁸¹⁴ AARP-01, p. 76, line 10 to p. 77, Table, lines 1-2. Note, the table shows AARP's recommended reductions as positive numbers and recommended funding levels as negative numbers.

overhead hardening deployed on a more limited basis.¹⁸¹⁵ As explained in Section 4.3.1.7.2 above, an indefinite delay would unnecessarily disrupt PG&E's ability to plan not only undergrounding but its other suite of wildfire mitigation efforts, unnecessarily delaying PG&E's efforts to implement a coordinated risk mitigation strategy that would address increasing wildfire risk in California. Authorizing half of PG&E's originally-requested capital is unnecessary and would undermine PG&E's efforts to deploy undergrounding at a wider scale in order to permanently mitigate more risk in the riskiest HFTD areas than can accomplished with overhead hardening.

4.4 Other Community Wildfire Risk Mitigations

PG&E forecast its Community Wildfire Risk Mitigations in Exhibit PG&E-04, Chapter 4, including:

- Wildfire Risk Mitigations (Chapter 4.0)¹⁸¹⁶,
- Situational Awareness and Forecasting (Chapter 4.1),
- PSPS Operations (Chapter 4.2),
- System Hardening, Enhanced Automation and PSPS Impact Mitigations (Chapter 4.3),
- CWSP PMO (Chapter 4.4),
- Information Technology for Wildfire Mitigations (Chapter 4.5); and
- EPSS (Chapter 4.6).

This section addresses PG&E's wildfire mitigations excluding System Hardening, which is discussed in Section 4.3 above.

PG&E's TY 2023 expense forecast for Other Community Wildfire Risk Mitigations presented in rebuttal testimony is \$370.565 million. PG&E's 2023 forecast presented in the JCE, including the September escalation adjustment, is \$404.834 million.¹⁸¹⁷

¹⁸¹⁵ PG&E-04, p. 4.3-44, line 9 to p. 4.3-48, line 9 and p. 4.3-51, Table 4.3-11, lines 1-3.

¹⁸¹⁶ Issues related to Chapter 4.0 are addressed in Section 4.24.

¹⁸¹⁷ PG&E-64, p. 3-2, Table 3A-1, lines 51-57, Column, "PG&E (with Sept 6 Non-Labor Escalation Adjustment)."

PG&E's capital forecast for Other Community Wildfire Risk Mitigations presented in rebuttal testimony is \$142.186 million in 2021, \$130.453 million in 2022, \$111.278 million in 2023, \$99,969 million in 2024, \$102,498 million in 2025, and \$105,853 million in 2026.

PG&E's forecast including the September escalation adjustment, is \$146.574 million in 2021, \$144.531 million in 2022, and \$128.081 million in 2023, \$118.054 million in 2024, \$120.805 million in 2025, and \$122.285 million in 2026.¹⁸¹⁸

PG&E did not segregate the forecasts for the individual Other Community Wildfire Risk Mitigations in the JCE.

4.4.1 Situational Awareness and Forecasting

PG&E's TY 2023 expense forecast presented in rebuttal testimony is \$43.416 million¹⁸¹⁹ and is undisputed. The expense forecast includes work tracked in Miscellaneous Expense (MWC AB).¹⁸²⁰ PG&E's capital expenditures forecast as reflected in rebuttal testimony is \$9.451 million in 2021, \$9.375 million in 2022, and \$4.601 million in 2023.¹⁸²¹ The capital forecast includes work tracked in the Miscellaneous Capital (MWC 21).¹⁸²² PG&E's capital forecast is also undisputed. The undisputed expense and capital forecasts are included in Appendix A.

4.4.2 Public Safety Power Shutoff Operations

PSPS is a critical element of PG&E's wildfire mitigation program. The Commission has affirmed that regulated utilities should implement PSPS events when necessary to prevent catastrophic wildfires. That is, when utilities "reasonably believe there is an imminent and

¹⁸¹⁸ PG&E-67, WP-2, lines "[Exhibit 4, Chapter] 4," MWCs 09, 21, 48, 49, 2A and 2F.

¹⁸¹⁹ PG&E-17, p. 2-4, Table 2-1, line 1.

¹⁸²⁰ PG&E-04, p. 4.1-3, Table 4.1-1, line 2.

¹⁸²¹ PG&E-17, p. 2-5, Table 2-2, line 1 (2021); p. 2-6, Table 2-3, line 1 (2022); p. 2-7, Table 2-4, line 1 (2023).

¹⁸²² PG&E-04, p. 4.1-3, Table 4.1-1, line 4.

significant risk that [] strong winds will topple its power lines onto tinder dry vegetation during periods of extreme fire hazard,”¹⁸²³ they may exercise their statutory authority to de-energize them.¹⁸²⁴

PG&E’s TY 2023 expense forecast for PSPS Operations presented in rebuttal testimony is \$115.266 million.¹⁸²⁵ The expense forecast includes work tracked in Miscellaneous Expense (MWC AB).¹⁸²⁶

PG&E’s capital expenditures forecast presented in rebuttal testimony is \$3.084 million in 2021, \$3.237 million in 2022, and \$0.262 million in 2023.¹⁸²⁷ The capital forecast includes work tracked in the Miscellaneous Capital MWC (MWC 21).

Cal Advocates and TURN recommend forecast reductions addressed in further detail below.

4.4.2.1 PG&E’s Forecast For Public Safety Power Shutoff Events (MWC AB) Is Reasonable

PG&E’s expense forecasts and Cal Advocates’ and TURN’s recommended adjustments for PSPS Events in MWC AB are summarized below.

¹⁸²³ D.12-04-024, pp. 3, 4, and 31.

¹⁸²⁴ PG&E-17, p. 4.2-6, lines 7-16.

¹⁸²⁵ PG&E-17, p. 4.2-3, Table 4.2-1, line 2.

¹⁸²⁶ PG&E-04, p. 4.1-3, Table 4.1-1, line 2.

¹⁸²⁷ PG&E-17, p. 2-5, Table 2-2, line 2 (2021); p. 2-6, Table 2-3, line 2 (2022); p. 2-7, Table 2-4, line 2 (2023).

**TABLE 4-3:
PSPS EVENTS - PG&E'S EXPENSE FORECAST AND
PARTIES' RECOMMENDED REDUCTIONS (\$000s)^(a)**

Party	2020 Rec.	2021	2022	2023
PG&E	\$141,178	\$127,920	\$119,254	\$115,266
Cal Advocates				\$(66,372)
TURN				\$(31,468)
(a) PG&E-17, p. 4.2-13, Table. 4.2-4, line 2; p. 4.2-3, Table 4.2-1, line 2.				

PG&E's PSPS Events forecast was based on the average cost per PSPS event recorded during 2019 and 2020, multiplied by a forecasted three annual PSPS events with an additional potential/borderline event per year.¹⁸²⁸ The forecasted number of events was based on a 10-year historical weather analysis.¹⁸²⁹

Cal Advocates and TURN recommend forecast reductions based on a different forecasting methodology.¹⁸³⁰ Cal Advocates argues that PG&E's PSPS Events forecast does not account for: (1) the declining number of customers impacted by a typical PSPS event; (2) duration of a PSPS event; (3) risk reduction from enhanced vegetation management and system hardening initiatives; (4) the number of customers impacted by an event; (5) the geographic area or number of miles of powerlines deenergized; and (6) the changes to the scope of PSPS events.¹⁸³¹ TURN argues that PG&E's PSPS Events forecast ignores the fact that PG&E seeks to substantially reduce the size and footprint of PSPS events over time.¹⁸³² In support, TURN states that a simple average of all PSPS event costs in 2019 and 2020 multiplied by the number of events in 2023, PG&E's forecast method, is unlikely to produce an accurate forecast for PSPS events conducted in 2023.¹⁸³³

¹⁸²⁸ PG&E-04, p. 4.2-20, lines 19-21 and lines 29-31.

¹⁸²⁹ PG&E-04, p. 4.2-2, lines 2-7.

¹⁸³⁰ CALPA-04, p. 11, lines 13-15.

¹⁸³¹ CALPA-04, p. 12, line 19 to p. 13, line 7.

¹⁸³² TURN-11, p. 54, lines 5-7.

¹⁸³³ TURN-11, p. 54, lines 15-17.

As explained below, Cal Advocates’ and TURN’s arguments are without merit. The subsections below address: (1) the reasonableness of PG&E’s forecasting methodology for PSPS events; and (2) the flaws in Cal Advocates’ and TURN’s proposed forecasting methodologies.

4.4.2.1.1 PG&E’s Method for Forecasting Costs For PSPS Events Is Reasonable

PG&E’s forecasting method for PSPS Events is straightforward. PG&E used 2019-2020 average costs multiplied by the number of expected events. Cal Advocates and TURN suggest a lower forecast because there were fewer, shorter, and smaller PSPS events in 2020. Their reasoning is flawed.

First, PG&E explained in rebuttal testimony that although PG&E used improved scoping techniques and PSPS mitigation strategies (e.g., remote grid) to reduce the number of customers impacted by PSPS events in 2020,¹⁸³⁴ PG&E is in the process of including additional factors in its PSPS decision-making model that may drive an expansion of PSPS events and associated costs in future years.¹⁸³⁵ Specifically, PG&E has incorporated asset health as well as the presence of known, high-risk vegetation conditions adjacent to powerlines into its PSPS decision-making model.¹⁸³⁶ Based on PG&E’s initial update of studies of 10 years of weather data from 2011-2020 and incorporation of the potential impact of proposed vegetation criteria to be used in the PSPS forecasting model, PG&E increased the number of anticipated PSPS events per year from three events to five events in its 2021 WMP, with a projected customer impact higher than PG&E’s 2023 GRC forecast for PSPS.¹⁸³⁷ Consequently, while PG&E is certainly making efforts to limit the number of customers impacted by a PSPS event, the PG&E’s 2023 GRC PSPS forecast remains conservative in comparison to the 2021 WMP.

¹⁸³⁴ PG&E-04, p. 4.2-9, lines 16-18.

¹⁸³⁵ PG&E-04, p. 4.2-9, lines 27-29.

¹⁸³⁶ PG&E-17, p. 4.2-9, lines 27-29.

¹⁸³⁷ PG&E-04, p. 4.2-20, lines 3-21.

Second, the duration of a PSPS event is not a significant cost factor.¹⁸³⁸ The duration of a PSPS event is the time period between when the first customer is de-energized and the last customer is restored, where possible.¹⁸³⁹ But the majority of PSPS event costs is for inspecting power lines following the end of the weather event, not costs prior to or during the event.¹⁸⁴⁰ Thus, the duration of the event does not significantly affect costs.¹⁸⁴¹ There is no basis for reducing PG&E's PSPS event forecast just because recent events may have had shorter durations.

Third, the risk reduction obtained through recent wildfire risk mitigation activities does not reduce the need for PSPS events. Extreme weather is the driver of a PSPS event; and because extreme weather is highly unpredictable year to year, under the most extreme weather conditions, the de-energizing of a line may still be necessary to protect against a catastrophic wildfire, even when mitigation activities such as vegetation management and overhead hardening have been performed on that line.¹⁸⁴² Furthermore, whether a line with mitigation falls within the scope of a PSPS event depends on exactly where the extreme weather is expected to occur.¹⁸⁴³ This type of pinpoint forecasting presents significant challenges due to the unpredictability of weather generally, much less at specific locations on a line where other

¹⁸³⁸ PG&E-17, p. 4.2-8, lines 28-29.

¹⁸³⁹ PG&E-17, p. 4.2-8, lines 18-20.

¹⁸⁴⁰ PG&E-17, p. 4.2-8, lines 25-26.

¹⁸⁴¹ PG&E-17, p. 4.2-8, lines 24-25.

¹⁸⁴² PG&E-17, p. 4.2-9, lines 9-12.

¹⁸⁴³ PG&E-17, p. 4.2-9, lines 12-14.

mitigations have been performed.¹⁸⁴⁴ For these reasons, PG&E did not factor risk reduction into the PSPS forecast.¹⁸⁴⁵

Fourth, although the scope of PSPS Events decreased from 2019 to 2020, that one-year decrease is not a proper basis to reduce PG&E forecast, because, as noted above, PG&E is updating its PSPS decision-making criteria with additional factors that may drive an expansion in PSPS scope in the future.¹⁸⁴⁶ This assessment will result in PG&E's executing PSPS starting in 2021 and beyond for powerlines where high priority vegetation tags have been identified, including on lines that may not have met the 2020 PSPS event criteria.¹⁸⁴⁷

In sum, PG&E's PSPS Events forecast is likely conservatively low. As reflected in the 2021 WMP, PG&E's updated forecasting anticipates more PSPS events than were used to develop the GRC forecast. Because the GRC forecast is likely low, not high, the Commission should not adopt Cal Advocates' and TURN's proposed adjustments that will further reduce necessary funding for PG&E's activities (inspecting power lines) prior to restoring power to customers following a PSPS event.

4.4.2.1.2 Cal Advocates' And TURN's Recommended Methods for Forecasting PSPS Event Costs Are Flawed

Cal Advocates developed its PSPS event forecast by modifying PG&E's calculations. First, Cal Advocates removed the cost per PSPS event in 2019 and instead only relies on the average cost per event in 2020. Second, Cal Advocates included the number of customers impacted in its 2023 calculations by forecasting the same number of customers impacted in

¹⁸⁴⁴ PG&E-17, p. 4.2-9, lines 14-17.

¹⁸⁴⁵ PG&E-17, PG&E's response to Data Request CalAdvocates_170-Q04, dated 12/8/21, p. App A-34.

¹⁸⁴⁶ PG&E-17, p. 4.2-9, lines 21-25.

¹⁸⁴⁷ PG&E-04, p. 4.2-2, line 23 to p. 4.2-3, line 3.

2021.¹⁸⁴⁸ TURN's proposed method for forecasting PSPS event costs: (1) recommends the average number of customers per event in 2021 be the starting point to forecast TY 2023 costs; (2) incorporates expected improvements in PSPS scope due to deployment of sectionalization devices in 2022 and 2023; and (3) incorporates the expected size (number of customers) of each PSPS event into a regression equation to forecast TY 2023 costs.¹⁸⁴⁹ These are not valid forecast adjustments proposals.

The inherent nature of extreme-weather-caused PSPS events and the evolving PSPS protocols make it difficult to predict accurately the number and scope of events each year and the associated event costs.¹⁸⁵⁰ PG&E is continually evaluating and evolving its PSPS protocols. PG&E conducted an analysis of how the current protocols would have impacted past events, analyzing past 2019-2021 weather events using the 2019, 2020, and current protocols. The analysis shows that while most historical PSPS events would have had smaller scope if the current 2021 protocol guidance had been applied, there are some exceptions, and some PSPS events may have been larger in scope under the current protocols. Additionally, some smaller PSPS events (i.e., the September 20, 2021 event) would only have been initiated under the current protocols and would not be scoped using either the 2019 or 2020 protocols.¹⁸⁵¹ Cal Advocates' exclusion of 2019 costs from the forecast, and TURN's recommendation to use 2021 alone as a starting point for the forecast with additional selective adjustments, both appear to arbitrarily narrow the forecast basis solely in order to arrive a lower forecast. Considering these factors, the Commission should determine that a forecast based on 2019-2020 average recorded

¹⁸⁴⁸ CALPA-04, p. 14, lines 3-7.

¹⁸⁴⁹ TURN-11, p. 54, line 17 to p. 55, line 5.

¹⁸⁵⁰ PG&E-17, PG&E's response to Data Request CalAdvocates_170-Q01, dated 12/8/21, pp. App A-32 to App A-33.

¹⁸⁵¹ PG&E's 2022 Wildfire Mitigation Plan, OEIS Docket #2022-WMP (Feb. 25, 2022), p. 858.

costs for PSPS events multiplied by a reasonable number of expected events (just 3 with an additional potential/borderline event per year) is a reasonable forecast approach.

4.4.2.2 PG&E's Capital Forecast For Public Safety Power Shutoff – Field Ops Tech Capital (MWC 21) Is Reasonable

PG&E's capital forecasts and Cal Advocates' and TURN's recommended adjustments for Public Safety Power Shutoff – Field Ops Tech Capital (MWC 21) are summarized below.

**TABLE 4-4:
PSPS FIELD OPS TECH CAPITAL - PG&E'S EXPENSE FORECAST AND
PARTIES RECOMMENDED REDUCTIONS (\$000s)^(a)**

Party	2020 Rec.	2021	2022	2023	2024	2025	2026
PG&E	\$2,397	\$3,084	\$3,237	\$262	\$269	\$277	\$284
Cal Advocates		\$(812)	\$(909)				

(a) PG&E-17, p. 4.2-13, Table 4.2-5, line 2; p. 4.2-14, Table 4.2-6, line 2.

For the PSPS Field Ops Tech Capital program, Cal Advocates recommends that PG&E's 2021 capital forecast should be replaced with 2021 annualized capital spending. Cal Advocates recommends an additional reduction of \$0.9 million in 2022.^{1852, 1853} The only reason Cal Advocates provides for the reduction of PG&E's 2022 forecast is that it should be equal to the 2021 recorded expenditures.¹⁸⁵⁴ Cal Advocates' reasoning for reducing the 2022 forecast does not make sense and is arbitrary. Cal Advocates does not analyze the specific program or any difference in the work forecast for different years or provide any explanation why they should be equal. Accordingly, there is no basis for reducing PG&E's 2022 forecast to 2021 levels.

4.4.3 Enhanced Automation and PSPS Impact Mitigations

PG&E's Enhanced Automation work involves the use of electrical technologies to reduce the possibility of ignitions caused by PG&E assets.¹⁸⁵⁵ These technologies include the

¹⁸⁵² Calculated as: PG&E's forecast for 2022 is \$0.994 million. Cal Advocates recommended forecast amount is \$0.086 million. $\$0.086 \text{ million} / \$0.994 \text{ million} = 86\%$. See CALPA-07, p. 7, Table 7-5.

¹⁸⁵³ CALPA-07, p. 7, Table 7-5.

¹⁸⁵⁴ CALPA-07, p. 9, lines 7-9.

¹⁸⁵⁵ PG&E-04, p. 4.3-2, lines 1-2.

following: (1) single phase reclosers with the capability to trip all phases (i.e., open all phases), eliminating the risk associated with wire down events; (2) distribution grid sensors that detect non equipment failure types that cannot be detected by existing detection methods or patrol techniques; (3) technology that can decrease overall wildfire ignition risk by detecting early stage equipment failure, enabling PG&E to conduct repairs before infrastructure fails; (4) technology that mitigates ignitions from line to ground faults such as wire down or tree contacts; and (5) technologies that detect an object approaching an energized power line and respond quickly to shut off power before the object impacts the line.¹⁸⁵⁶

Programs for mitigating the impacts of PSPS on customers include the installation of sectionalizing devices and support for Temporary Generation (TG) programs that support temporary microgrids.¹⁸⁵⁷

PG&E's TY 2023 expense forecast presented in rebuttal testimony is \$11.595 million¹⁸⁵⁸ and is uncontested. The expense forecast includes three types of expense activities: (1) Remote Grid, Sensor IQ Generation Enablement and Deployment (MAT AB#); (2) Asset Health and Performance Center (MAT FZA); and (3) Remote Grid (MAT KAT). The undisputed expense forecast is included in Appendix A.

PG&E's capital expenditures forecast presented in rebuttal testimony is \$104.351 million in 2021, \$92.542 million in 2022, and \$81.116 million in 2023.¹⁸⁵⁹ PG&E's capital forecast consists of three MWCs: (1) Miscellaneous Capital (MWC 21), (2) Electric Distribution Install/Replace Overhead Assets (MWC 2A), and (3) Distribution Circuit/Zone Reliability (MWC 49).

¹⁸⁵⁶ PG&E-04, p. 4.3-2, lines 2-15.

¹⁸⁵⁷ PG&E-04, p. 4.3-2, lines 13-15.

¹⁸⁵⁸ PG&E-17, p. 4.3-3, Table 4.3-1, line 4.

¹⁸⁵⁹ PG&E-17, p. 4.3-72, Table 4.3-7, lines 2-9.

Within these MWCs, the forecast for Distribution Line Automation (MAT 49A), Sectionalizing Devices (MAT 49H), Temporary Distribution Microgrids (MAT 49M), Rapid Earth Fault Current Limiter (MAT 49R), and Single Phase Recloser (49T) are uncontested except for Cal Advocates’ recommendation regarding 2021 recorded costs (see Appendix A).

The capital forecasts related to Expulsion Fuse Replacement (MAT 2AP) and Distribution Grid Sensors (MAT 49I) are contested. PG&E addresses intervenors’ recommendations below.

4.4.3.1 PG&E’s Forecasts For Disputed MATs Are Reasonable

4.4.3.1.1 PG&E’s Capital Forecast For Expulsion Fuse Replacement Program (MAT 2AP) Is Reasonable

The Expulsion Fuse Replacement program only targets non-exempt expulsion fuses. Non-exempt equipment is equipment that may generate electrical arcs, sparks, or hot material during its normal operation. If a non-exempt expulsion fuse operates, it has the potential to spread hot molten metal material that could cause an ignition.¹⁸⁶⁰ PG&E’s capital forecasts and Cal Advocates’ recommended adjustments for PG&E’s forecast for Expulsion Fuse Replacement Program (MAT 2AP) are summarized below.

**TABLE 4-5:
EXPULSION FUSE REPLACEMENT PROGRAM (MAT 2AP) - PG&E’S CAPITAL
FORECAST AND PARTIES RECOMMENDED REDUCTIONS (\$000S)^(a)**

Party	2020 Rec.	2021	2022	2023	2024	2025	2026
PG&E	\$7,847	\$15,125	\$15,388	\$15,752	\$16,257	\$16,777	\$17,314
Cal Advocates		\$(6,415)	\$(8,135)	\$(8,523)			
(a) PG&E-17, p. 4.3-4, Table 4.3-2, line 3; p. 4.3-72, Table 4.3-7, line 3; p. 4.3-73, Table 4.3-8, line 3.							

Cal Advocates recommends replacing PG&E’s 2021 forecast with 2021 recorded costs. Cal Advocates then recalculates PG&E’s 2022 and 2023 forecast by multiplying the number of

¹⁸⁶⁰ PG&E-04, p. 4.3-52, lines 3-7.

forecast units each year by PG&E's 2021 recorded unit cost, which Cal Advocates calculated by dividing 2021 recorded costs by number of units installed.¹⁸⁶¹

Cal Advocates' forecasting methodology is not reasonable because the work conducted in 2021 is not necessarily representative of the work forecast by PG&E for the GRC period. For example, PG&E has a population of 25,000-32,000 non-exempt fuses connected to transformers in HFTD areas.¹⁸⁶² Most of these are transformer bushing mounted cut-outs, which when replaced may require the addition of a cross-arm or even the replacement of the pole, therefore increasing unit costs for these particular replacement activities. PG&E will begin replacing non-exempt transformer fuses in 2022.¹⁸⁶³ Therefore, the recorded costs for 2021 (which Cal Advocates uses to calculate an average unit cost) are not a reasonable proxy for the subsequent years. PG&E's forecast should not be reduced based upon recorded costs/average unit costs that are not representative of the work planned.

4.4.3.2 PG&E's Capital Forecast For Line Sensor (MAT 49I) Is Reasonable

MAT 49I includes three types of sensors: (1) Line Sensors and Communicating Faulted Circuit Indicators (cFCI), (2) Event Classification Through Current and Voltage Monitoring Sensors (ECCVM)/Early Fault Detection Sensors, and (3) Radio Frequency (RF) Sensors/Distribution Fault Anticipation technology.¹⁸⁶⁴ These sensors are part of PG&E's Enhanced Automation programs for wildfire mitigation, where their installation will continue to reduce the possibility of ignitions caused by PG&E assets.¹⁸⁶⁵ PG&E's capital forecasts and Cal Advocates' recommended adjustments for PG&E's Line Sensor program (MAT 49I) are summarized below.

¹⁸⁶¹ CALPA-07, p. 17, line 10 to p. 18, line 3.

¹⁸⁶² PG&E-17, p. 4.3-58, lines 8-9.

¹⁸⁶³ PG&E-04, p. 4.3-53, lines 14-23.

¹⁸⁶⁴ PG&E-04, p. 4.3-73, lines 7-9.

¹⁸⁶⁵ PG&E-04, p. 4.3-2, lines 1-3.

**TABLE 4-6:
DISTRIBUTION LINE SENSORS (MAT 49I) - PG&E'S CAPITAL FORECAST AND PARTIES
RECOMMENDED REDUCTIONS (\$000s)^(a)**

Party	2020 Rec.	2021	2022	2023	2024	2025	2026
PG&E	\$2,272	\$12,369	\$23,036	\$22,653	\$21,711	\$22,696	\$24,405
Cal Advocates		\$(10,198)	\$(4,837)	\$(5,054)			
(a) PG&E-17, p. 4.3-4, Table 4.3-2, line 5; 4.3-72, Table 4.3-7, line 6; p. 4.3-73, Table 4.3-6, line 6.							

Similar to its proposed methodology for forecasting the Expulsion Fuse program, as discussed above, Cal Advocates recalculates PG&E's 2022 and 2023 forecast for the Line Sensor program by multiplying the number of forecast units each year by PG&E's 2021 recorded unit cost, which Cal Advocates calculates by dividing the 2021 recorded costs by the number of units installed.

Again, it is unreasonable to use PG&E's 2021 recorded costs as a basis for its 2022 and 2023 forecasts because the work completed in 2021 is very different than the work forecast for 2022 and 2023. There are two basic components and costs related to the line sensor program: (1) the labor and materials to install an individual device; and (2) the information technology operational infrastructure supporting the increased volume of the line sensor equipment.¹⁸⁶⁶ PG&E explained in its testimony that deployment costs should also factor in IT costs for data integration and grid sensing analytics to support grid operations.¹⁸⁶⁷ In 2021, PG&E incurred costs for labor and materials to install devices but did not perform any IT integration work.¹⁸⁶⁸ In 2022 and 2023, however, PG&E will install devices and will conduct the necessary IT work including building the IT infrastructure, conducting integration work, and building out operations centers and other facilities.¹⁸⁶⁹ PG&E explained in its workpapers that the 2022 plan funds additional IT spend to integrate all of the sensor technologies and that each system has its own

¹⁸⁶⁶ PG&E-04, p. 4.3-58, lines 3-12.

¹⁸⁶⁷ PG&E-04, p. 4.3-57, lines 23-25.

¹⁸⁶⁸ PG&E-04, p. 4.3-58, lines 18-19.

¹⁸⁶⁹ PG&E-17, p. 4.3-59, lines 7-9.

development and integration schedule and results in varying annual totals.¹⁸⁷⁰ Because PG&E will conduct IT work in 2022 and 2023 that it did not do in 2021, the recorded costs and associated unit costs for 2021 are not a reasonable proxy for spending in this GRC period and PG&E's forecast should not be reduced.

4.4.3.3 Distribution Grid Sensor (MWC 49)

Cal Advocates notes that PG&E planned to replace its entire recloser assembly in 2021 because the product it received from the original vendor was unreliable.¹⁸⁷¹ Because the recloser was unreliable, Cal Advocates recommends that PG&E be required to provide customer refunds when and if it receives reimbursement from the vendor.¹⁸⁷² PG&E agrees and will credit the WMBA with any amounts received from the manufacturer.¹⁸⁷³

4.4.4 Community Wildfire Safety Program Project Management Organization (PMO)

PG&E's TY 2023 expense forecast presented in rebuttal testimony is \$13.460 million¹⁸⁷⁴ and is undisputed. The expense forecast includes work tracked in Miscellaneous Expense (MWC AB) as reflected in Appendix A.

4.4.5 Information Technology for Wildfire Mitigations

PG&E's TY 2023 expense forecast presented in rebuttal testimony is \$35.700 million¹⁸⁷⁵ and is undisputed. The expense forecast includes work tracked in the three MWCs: Miscellaneous Expense (MWC AB); Manage Various Balancing Account Processes (MWC IG); and Maintain IT Applications and Infrastructure (MWC JV).

¹⁸⁷⁰ PG&E-04, WP 4-114.

¹⁸⁷¹ CALPA-07, p. 20, lines 18-19.

¹⁸⁷² CALPA-07, p. 21, lines 17-19.

¹⁸⁷³ PG&E-17, p. 4.3-55, lines 12-13.

¹⁸⁷⁴ PG&E-17, p. 2-4, Table 2-1, line 4.

¹⁸⁷⁵ PG&E-17, p. 2-4, Table 2-1, line 5.

PG&E capital expenditures forecast as reflected in rebuttal testimony is \$25.300 million in 2021, \$25.300 million in 2022, and \$25.300 million in 2023.¹⁸⁷⁶ PG&E's capital work is tracked in MWC 2F, Build IT Applications and Infrastructure. PG&E's capital forecast is undisputed. The undisputed expense and capital forecasts are included in Appendix A.

4.4.6 Enhanced Powerline Safety Settings

EPSS is a critical element of PG&E's wildfire mitigation program. The purpose of the EPSS program is to reduce wildfire risk by minimizing the probability of an ignition event when a fault occurs on an electric distribution line in high fire risk areas during periods of elevated fuels and weather-related wildfire risk. EPSS achieves this by increasing the sensitivity and speed of system protective devices on circuits in HFTD and HFRA areas (and select circuits adjacent to those areas) so that power is automatically shut off within one-tenth of a second if an object contacts a distribution line, reducing the potential for an ignition.¹⁸⁷⁷

PG&E's TY 2023 expense forecast for EPSS as reflected in rebuttal testimony is \$151.129 million.¹⁸⁷⁸ The expense forecast includes work tracked in six MATs, five of which – Control Center Work (MATs BAF and BAH); Reprogram Devices and Engineering (MAT FZA); Substation Support (MAT GC2); and Manage Various Balancing Account Processes (MWC IG#) – are undisputed and reflected in Appendix A.

The majority of PG&E's EPSS forecast is for post-outage patrols on EPSS-enabled circuits to ensure the system is safe and to facilitate restoration of the outage as quickly as possible. This patrol work is tracked in MWC BH. EPSS patrols require the deployment of ground and/or aerial assets to provide a full patrol and investigation of the circuit segment of the protective device that operated during the outage from the beginning of the outage zone to the

¹⁸⁷⁶ PG&E-17, p. 2-5, Table 2-2, line 4 (2021); p. 2-6, Table 2-3, line 4 (2022); p. 2-7, Table 2-4, line 4 (2023).

¹⁸⁷⁷ PG&E-04, p. 4.6-1, line 20 to p. 4.6-2, line 1.

¹⁸⁷⁸ PG&E-17, p. 2-4, Table 2-1, line 6.

next protective device and/or end of each line. Troublemens perform the bulk of these patrols. The number of outages and size of the zones to be patrolled will drive the specific additional resource requirements for personnel and air assets. Helicopters will be used, when appropriate, to complete patrols and restore power as soon as possible.¹⁸⁷⁹ TURN disputes PG&E's MWC BH forecast and recommends the following reductions:

**TABLE 4-7:
EPSS - PG&E'S EXPENSE FORECAST AND
PARTIES RECOMMENDED REDUCTIONS (\$000s)^(a)**

Party	2020 Rec.	2021	2022	2023
PG&E(b)	\$0	\$18,203	\$148,921	\$151,129
TURN				\$(64,080)
(a) PG&E-17, p. 4.6-10, Table. 4.6-2, line 9; p. 4.6-3, Table 4.6-1, line 8. (b) PG&E's forecast for EPSS does not align to the normal attrition year escalation amounts. PG&E's attrition year forecast for EPSS is: \$146,302 million in 2024; \$140.825 million in 2025; and \$133.710 million in 2026. (PG&E-04, p. 4.6-21, Table 4.6-7, line 7).				

TURN asserts that PG&E's forecast for EPSS patrol costs is flawed because it is based on the number of circuits subject to EPSS-related outages rather than the number of circuit miles impacted by the outage.¹⁸⁸⁰ TURN recommends using 2021 recorded unit costs per circuit mile, rather than per circuit, because using recorded unit costs on a per circuit basis is unlikely to lead to an accurate forecast because circuits vary widely in length.¹⁸⁸¹

The Commission should not adopt TURN's recommendation for MWC BH. PG&E's choice to forecast on a per circuit basis was appropriate for this GRC given the limited data PG&E had about its EPSS program at the time it developed its forecast. PG&E implemented its EPSS program in July 2021 and enabled approximately 11,500 HFTD circuit miles across 170 circuits to operate in EPSS mode. In 2021, PG&E's EPSS program was active from July through November. There were no recorded expenses in 2020 for the EPSS program because it is a new

¹⁸⁷⁹ PG&E-17, p. 4.6-5, lines 7-23.

¹⁸⁸⁰ TURN-11, p. 49, lines 20-22.

¹⁸⁸¹ TURN-11, p. 50, lines 7-9.

program. Therefore, PG&E had only a few months of recorded data as the basis for its TY 2023 forecast. At the time PG&E developed its forecast it was appropriate to use the available data as a proxy for future costs because PG&E did not know exactly what factors would ultimately impact the forecast and to what degree.¹⁸⁸²

In addition, since developing the forecast PG&E knows more about the factors that impact EPSS costs. One of the things PG&E knows more about now is the extent to which the limited number of available resources that can respond after an EPSS outage impacts the cost. Depending on the number, timing and location of outages, PG&E's cost per outage can vary significantly as PG&E may have to rely on more contract resources, pay labor premiums, and rely to varying degrees on aviation resources for post-outage inspections. Multiple, overlapping outages increase the reliance on contract resources and overtime pay.¹⁸⁸³ And multiple outages are more likely to occur as more circuits are EPSS-enabled, which may lead to increases in per outage costs. Despite this, PG&E reduced its 2023 forecast by 20 percent per circuit to account for improvements in device programming since 2021 that should reduce the number of EPSS-related outages on a given circuit.¹⁸⁸⁴

TURN calculates a lower unit cost per circuit mile than PG&E does. But TURN's unit cost is based 2021 costs, which do not apply directly to the 2023 forecast because of changes in the length of time EPPS is expected to be activated. The PG&E cost per circuit mile that TURN calculates is based on seven months of forecast costs in 2023 (May through November).¹⁸⁸⁵ The TURN cost per circuit mile is based on 2021 forecast costs for five months (July through November), of which one month (July) included only one quarter as many EPSS activated

¹⁸⁸² PG&E-17, p. 4.6-6, line 20 to p. 4.6-7, line 4.

¹⁸⁸³ PG&E-17, p. 4.6-7, lines 7-17.

¹⁸⁸⁴ PG&E-17, p. 4.6-7, lines 17-18 and 26-30.

¹⁸⁸⁵ See PG&E-17, PG&E's response to Data Request TURN_155-Q03 and Attachment TURN_155-Q03Atch02, dated 3/22/22, pp. App A-90 and App A-98. Calculated as \$112,510 (2023 forecast for MWC BH) / 44,000 circuit miles = \$2.56/circuit mile.

circuits. PG&E's forecast assumes that there will be increased volume and/or frequency of outages, and thus more patrol costs on circuits activated for seven months compared to circuits activated for four months. This difference in the number of months that EPSS is activated in 2022 (and in future years) drives the variance in the unit cost between PG&E's and TURN's proposals. It is unreasonable to apply the lower cost per circuit mile—based on less than four full months of data—to a program that in 2023 will operate for seven months at a minimum.¹⁸⁸⁶

4.5 Emergency Preparedness and Response

Emergency Preparedness and Response (EP&R) funding allows PG&E to prepare and plan for responding to emergency events by having integrated plans and appropriate facilities, logistics, technology, and processes in place prior to an event occurring. In particular, the funding will position EP&R to be able to identify risks and hazards across the threat landscape, develop plans, and train and exercise our response to effectively coordinate emergency response efforts among PG&E's various lines of businesses and collaborate with external governmental emergency response agencies.¹⁸⁸⁷

PG&E's TY 2023 expense forecast for EP&R presented in rebuttal testimony is \$26.451 million.¹⁸⁸⁸ PG&E's TY 2023 expense forecast presented in the JCE, including the September escalation adjustment, is \$29.557 million.¹⁸⁸⁹ The expense forecast includes work tracked in MWC AB (Miscellaneous Expense).

PG&E's capital expenditures forecast for EP&R presented in rebuttal testimony is \$2.046 million for 2021, \$1.966 million for 2022, and \$5.502 million for 2023,¹⁸⁹⁰ \$5.409 million in

¹⁸⁸⁶ PG&E-17, p. 4.6-8, line 8 to p. 4.6-9, line 3.

¹⁸⁸⁷ PG&E-04, p. 5-1, lines 14-23.

¹⁸⁸⁸ PG&E-17, p. 2-4, Table 2-1, line 7.

¹⁸⁸⁹ PG&E-64, p. 3-2, Table 3A-1, line 58.

¹⁸⁹⁰ PG&E-17, p. 2-5, Table 2-2, line 5 (2021); p. 2-6, Table 2-3, line 5 (2022); p. 2-7, Table 2-4, line 5 (2023).

2024, \$5.457 million in 2025, and \$5.626 million in 2026.¹⁸⁹¹ PG&E's capital expenditures forecast including the September escalation adjustment, is \$2.109 million in 2021, \$2.143 million for 2022, and \$6.477 million for 2023, \$6.458 million in 2024, \$6.472 million in 2025, and \$6.561 million in 2026.¹⁸⁹² PG&E's capital work is tracked in MWC 21 (EP&R Capital).

No party disputed PG&E's expense and capital forecasts, as indicated in Appendix A.

4.6 Electric Emergency Recovery

The difference between the EP&R forecast discussed above and PG&E's Electric Emergency Recovery (EER) forecast is that the EP&R forecast relates to PG&E's *planning* for emergencies *before* they occur, whereas the EER forecast relates to PG&E's *response* to emergencies *after* they occur. Specifically, as explained in testimony, the funding requested for EER is necessary for PG&E to: (1) respond to incidents and outages during routine and major emergencies; (2) perform equipment repairs and replacements related to routine and major emergencies; and (3) straight-time labor when responding to CEMA-eligible events.¹⁸⁹³ PG&E's expense and capital forecast for EER consists of three components: (1) Routine Emergency; (2) Major Emergency; and (3) Catastrophic Event Straight-Time Labor.

PG&E's TY 2023 expense forecast for EER presented in rebuttal testimony is \$136.466 million.¹⁸⁹⁴ PG&E's TY 2023 expense forecast in the JCE, including the September escalation adjustment, is \$149.216.¹⁸⁹⁵ The expense forecast includes work tracked in MWC BH (Routine Emergency Expense) and MWC IF (Major Emergency Expense). PG&E's expense forecasts for Routine Emergency (MWC BH) and Major Emergency (MWC IF) are uncontested. See Appendix A.

¹⁸⁹¹ PG&E-67, WP-2, line "[Exhibit 4, Chapter] 5," MWC 21.

¹⁸⁹² PG&E-67, WP-2, line "[Exhibit 4, Chapter] 5," MWC 21.

¹⁸⁹³ PG&E-04, p. 6-1, lines 10-16.

¹⁸⁹⁴ PG&E-17, p. 2-4, Table 2-1, line 8.

¹⁸⁹⁵ PG&E-64, p. 3-2, Table 3A-1, lines 59-60.

PG&E capital expenditures forecast for EER presented in rebuttal testimony is \$269.595 million for 2021, \$311.368 million for 2022, \$319.184 million for 2023, \$328.424 million in 2024, \$337.910 million in 2025, and \$347.674 million in 2026.¹⁸⁹⁶ PG&E's capital expenditures forecast including the September escalation adjustment is \$277.941 million for 2021 \$339.418 million for 2022, and \$360.523 million for 2023 \$383.822 million in 2024, \$395.986 million in 2025, and \$398.355 million in 2026.¹⁸⁹⁷ The capital forecast includes work tracked in MWC 17 (Routine Emergency Capital) and MWC 95 (Major Emergency Capital – excluding CEMA Straight Time).

Cal Advocates opposes portions of PG&E's capital forecasts for Routine Emergency (MWC 17) and Major Emergency (MWC 95), based on a forecast methodology that departs from prior GRC precedent. Cal Advocates recommends capital forecast reductions of \$55.629 million for 2021, \$60.318 million for 2022, \$61.463 million for 2023,¹⁸⁹⁸ \$16.817 million for 2024, \$17.271 million for 2025, and \$17.738 million for 2026.¹⁸⁹⁹

Cal Advocates and TURN also oppose PG&E's expense and capital forecast for the proposed Catastrophic Event Straight Time Labor Balancing Account (CESTLBA). Cal Advocates and TURN recommend reductions of \$20.079 million to PG&E's TY 2023 expense forecast for EER related to the CESTBLA.¹⁹⁰⁰ TURN also recommends capital forecast reductions of \$15.541 million in 2021, \$15.945 million for 2022, \$16.375 million for 2023, \$16.817 million for 2024, \$17.271 million for 2025, and \$17.738 million for 2026.¹⁹⁰¹ These arguments are addressed below.

¹⁸⁹⁶ PG&E-17, p. 6-16, Table 6-5, line 4.

¹⁸⁹⁷ PG&E-67, WP-2, lines "[Exhibit 4, Chapter] 6," MWCs 17 and 95.

¹⁸⁹⁸ PG&E-17, p. 6-17, Table 6-6, line 4 (2021-2022); p. 6-4, Table 6-2, line 4 (2023).

¹⁸⁹⁹ PG&E-17, p. 6-4, Table 6-2, line 4.

¹⁹⁰⁰ PG&E-17, p. 6-3, Table 6-1, line 4.

¹⁹⁰¹ PG&E-17, p. 6-17, Table 6-6, line 4 (2021-2022); p. 6-4, Table 6-2, line 4 (2023-2026).

4.6.1 PG&E's Routine Emergency (MWC 17) Forecast Is Reasonable

Routine Emergency (MWC 17) costs generally cover PG&E's power restoration efforts for emergency outages caused by equipment failure.¹⁹⁰² PG&E's capital forecasts and Cal Advocates' recommended adjustments for Routine Emergency response activities from 2020-2026 are summarized below.

**TABLE 4-8:
ROUTINE EMERGENCY - PG&E'S CAPITAL FORECAST AND
PARTIES RECOMMENDED REDUCTIONS (\$000s)^(a)**

Party	2020 Rec.	2021	2022	2023	2024	2025	2026
PG&E	\$247,499	\$193,244	\$233,354	\$239,188	\$246,137	\$253,271	\$260,615
Cal Advocates		\$(31,977)	\$(36,094)	\$(36,602)			
(a) PG&E-17, p. 6-4, Table 6-2, line 1; p. 6-16, Table 6-5, line 1; p. 6-17, Table 6-6, line 1.							

Cal Advocates' recommended reductions to PG&E's Routine Emergency (MWC 17) capital forecast is based on two alternative forecasting proposals.¹⁹⁰³ First, Cal Advocates proposes using a 5-year average of historical costs, rather than the 3-year average adopted in past GRC decisions and used again by PG&E in this GRC.¹⁹⁰⁴ Second, Cal Advocates recommends reducing the forecast based on PG&E's completion of risk-mitigation work, which according to Cal Advocates should reduce the occurrence of catastrophic events and their associated costs.¹⁹⁰⁵ The Commission should reject these alternative forecasting proposals. As explained in further detail below, Cal Advocates' averaging proposal is inconsistent with PG&E's historical GRC forecasting methodology for these types of costs, as approved by the Commission in prior GRCs. In addition, PG&E's forecast already reflects risk reductions obtained through PG&E's various risk-mitigation work completed to date.

¹⁹⁰² PG&E-04, p. 6-7, lines 7-9.

¹⁹⁰³ CALPA-06, p. 11, lines 9-13.

¹⁹⁰⁴ CALPA-06, p. 12, lines 7-13.

¹⁹⁰⁵ CALPA-06, p. 12, line 14 to p. 15, line 15.

In regard to forecasting methodologies, PG&E routinely uses and the Commission has approved using 3-year historical averages to forecast costs in Electric Distribution.¹⁹⁰⁶ This methodology allows PG&E to account for some year-to-year variability, while also capturing the most up to date labor and materials costs.¹⁹⁰⁷ PG&E uses a 5-year average less frequently in certain limited circumstances, because it does not reflect current labor and materials costs as closely as a 3-year average.¹⁹⁰⁸ In this GRC (as in prior GRCs), PG&E used a 3-year average to forecast Routine Emergency in order to capture the most up to date labor and materials costs, but used a 5-year average to forecast Major Emergency (MWC 95) because the number and scope of major emergencies such as storms, earthquakes and fires can vary significantly, making a 5-year average appropriate.¹⁹⁰⁹ Again, PG&E notes that it has used and the Commission has approved forecast methodologies for Routine Emergency activities based on a 3-year average and Major Emergency activities based on a 5-year average for multiple GRC proceedings.¹⁹¹⁰ There is no reason to depart from that precedent in this GRC. Cal Advocates' proposal to use a 5-year average for the Routine Emergency capital forecast is inconsistent with Commission precedent approving PG&E's routine emergency forecasts in prior GRCs.

In addition, there is no valid reason to reduce PG&E's Routine Emergency capital forecasts based on PG&E's completion of risk-mitigation work in prior years. Cal Advocates suggests that this work should reduce the frequency and impact of ignitions and therefore costs going forward. To the extent Cal Advocates is correct, PG&E's forecast already reflects the reduced risk, in that the recorded costs used in the averaging reflect the financial consequences

¹⁹⁰⁶ D.20-12-005, p. 95.

¹⁹⁰⁷ PG&E-17, p. 6-7, lines 13-16.

¹⁹⁰⁸ PG&E-17, p. 6-7, lines 16-17.

¹⁹⁰⁹ PG&E-17, p. 6-7, lines 16-20.

¹⁹¹⁰ PG&E-17, p. 6-7, lines 21-24. D.20-12-005 (GRC 2020), pp. 94-95. D.17-05-013 (2017 GRC), p. 246, OP 1 (adopting the Settlement Agreement between parties, including the Routine Emergency forecast based on a 3-year average). See, A.15-09-001, Exhibit (PG&E-23) p. 4-6, lines 13-15.

of routine emergency response activities that occurred post risk-mitigation work.¹⁹¹¹ That is, if there are any reduced emergency response costs due to the risk-mitigation work, those reduced costs are reflected in the historical costs used in the 3-year average of those costs. There is no basis for applying an additional speculative downward adjustment, particularly given that doing so would depart from historical averages. This issue is also discussed in Section 4.2.3.4 above.

In sum, the Commission should reject Cal Advocates’ proposal to use a 5-year average with an additional downward adjustment and should adopt PG&E’s Routine Emergency capital forecast based on a 3-year average. The funding requested by PG&E is necessary for PG&E to effectively respond to routine emergencies caused by equipment failures, in compliance with GO 166 (Standards for Operation, Reliability, and Safety) during Emergencies and Disasters.

4.6.2 PG&E’s Major Emergency (MWC 95 Excluding CESTLBA) Forecast Is Reasonable

Major Emergency (MWC 95) costs generally cover PG&E’s power restoration efforts for emergency outages caused by weather events, wildfires, and other natural disasters.¹⁹¹² PG&E’s capital forecasts and Cal Advocates’ recommended adjustments for Major Emergency (MWC 95) response activities from 2020-2026 are summarized below.

**TABLE 4-9:
MAJOR EMERGENCY - PG&E’S CAPITAL FORECAST AND PARTIES RECOMMENDED
REDUCTIONS (\$000S)^(A)**

Party	2020 Rec.	2021	2022	2023	2024	2025	2026
PG&E	\$64,253	\$60,810	\$62,069	\$63,621	\$65,470	\$67,367	\$69,321
Cal Advocates		\$(8,111)	\$(8,279)	\$(8,486)			
(a) PG&E-17, p. 6-4, Table 6-2, line 2; p. 6-16, Table 6-5, line 2; p. 6-17, Table 6-6, line 2.							

As with the Routine Emergency forecast, Cal Advocates recommends reducing PG&E’s Major Emergency capital forecast on the ground that completed risk mitigations should reduce

¹⁹¹¹ PG&E-17, p. 3-32, lines 4-12.

¹⁹¹² PG&E-04, p. 6-7, lines 9-10.

the frequency or impact of emergencies.¹⁹¹³ Similar to the discussion above in Section 4.6.1, there is no valid reason for reducing the forecast, which is based on historical costs that already reflect any Major Emergency cost reductions realized through reduced risks resulting from PG&E's mitigation work. The Commission should reject Cal Advocates' proposed reduction and adopt PG&E's Major Emergency capital forecasts.

4.6.3 PG&E's Proposal to Establish A CEMA Straight Time Labor Balancing Account (MWCs IF and 95) Is Reasonable

PG&E proposes to recover straight time (ST) labor costs associated with its repair and restoration activities for CEMA-eligible events through a new two-way balancing account referred to as the CESTLBA. Under the proposed two-way balancing account, the CESTLBA will be trued up annually through PG&E's annual electric and annual gas true up advice letters.¹⁹¹⁴ Cal Advocates and TURN oppose PG&E's proposal.¹⁹¹⁵ PG&E's expense and capital forecast and Cal Advocates' and TURN's recommended reductions for the CESTLBA are summarized below.

**TABLE 4-10:
CESTLBA - PG&E'S EXPENSE FORECAST AND PARTIES
RECOMMENDED REDUCTIONS (\$000s)^(a)**

Party	2020 Rec.	2021	2022	2023
PG&E	\$--	\$18,737	\$19,397	\$20,079
Cal Advocates				\$(20,079)
TURN				\$(20,079)

(a) PG&E-17, p. 6-16, Table 6-4, line 3 (2021 and 2022); PG&E-17, p. 6-3, Table 6-1, line 3.

**TABLE 4-11:
CESTLBA - PG&E'S CAPITAL FORECAST AND PARTIES
RECOMMENDED REDUCTIONS (\$000s)^(a)**

Party	2020 Rec.	2021	2022	2023	2024	2025	2026
PG&E		\$15,541	\$15,945	\$16,375	\$16,817	\$17,271	\$17,738

¹⁹¹³ CALPA-06, p. 12, lines 14-16.

¹⁹¹⁴ PG&E-04, p. 6-27, lines 6-8.

¹⁹¹⁵ CALPA-04, pp. 16, line 18 to p. 19, line 15; TURN-12, p. 2, lines 2-4; TURN-13, p. 29, line 15.

Party	2020 Rec.	2021	2022	2023	2024	2025	2026
Cal Advocates		\$(15,541)	\$(15,945)	\$(16,375)	\$(16,817)	\$(17,271)	\$(17,738)
TURN		\$(15,541)	\$(15,945)	\$(16,375)	\$(16,817)	\$(17,271)	\$(17,738)
(a) PG&E-17, p. 6-4, Table 6-2, line 3; p. 6-16, Table 6-5, line 3; p. 6-17, Table 6-6, line 3.							

Cal Advocates argues that CEMA is a non-GRC activity and that CEMA straight-time labor and overheads cannot be recovered through the GRC.¹⁹¹⁶ TURN argues that PG&E's CEMA straight time labor costs associated with existing employees are not incremental and are already funded in the GRC and GT&S proceedings.¹⁹¹⁷ The Commission should reject these arguments and approve the CESTLBA in order to avoid the persistent, longstanding dispute regarding the recovery of CEMA straight-time labor costs in the CEMA cost-review proceedings.

As explained in testimony, CEMA cost recovery disputes have been going on for several years in the CEMA cost-review proceedings, resulting in substantial uncertainty that should be resolved once and for all in this GRC. Historically, dating back at least a decade, Cal Advocates and TURN have argued against the recovery of CEMA ST labor in PG&E's CEMA filings on the ground that the ST labor costs associated with PG&E's CEMA related restoration and repair activities are not incremental to base rates approved in the GRC and GT&S proceedings. In particular, Cal Advocates and TURN have argued that when PG&E uses existing staff to respond to a CEMA event, the CEMA ST labor associated with the response activities has already been funded through GRC and GT&S approved rates.¹⁹¹⁸ PG&E has disputed this argument by explaining that PG&E's GRC and GT&S forecasts are activity based and seek funding for work activities specifically identified in the GRC, not staffing, and that PG&E specifically removed CEMA recorded costs (including CEMA ST labor) from the recorded costs used to develop PG&E's GRC forecasts. For both these reasons, it has been manifestly incorrect for Cal

¹⁹¹⁶ CALPA-04, p. 16, line 18 to p. 19, line 15.

¹⁹¹⁷ TURN-12, p. 6, lines 16-18.

¹⁹¹⁸ TURN-12, p. 6, lines 16-18. See also, A.20-09-019, Exhibit (PA-08), p. 4, line 10 to p. 11, line 23; A.21-09-008, HE-PA-04: Exhibit (Cal Advocates-04), Section V.

Advocates and TURN to contend in the CEMA cost-review proceedings that CEMA ST labor costs for these employees have already been funded in a GRC. They have not.

To avoid this longstanding dispute going forward in the CEMA review proceedings, PG&E's CEMA ST labor forecast in this GRC is intended to solely recover ST labor associated with CEMA events. If PG&E's proposal is approved, PG&E would record the CEMA ST labor in a two-way CESTLBA so that any underspent amounts may be returned to customers and overspent amounts are allowed for recovery. PG&E would stop recording CEMA ST labor costs to the CEMA, and PG&E's CEMA applications would only seek recovery of other non-labor-related expense, capital expenditures, certain limited overheads, and overtime and double time labor costs¹⁹¹⁹ associated with PG&E's repair and restoration activities following a CEMA-eligible event.

Cal Advocates' and TURN's opposition to the proposed CESTLBA and CEMA ST labor forecast is perplexing given the position they have consistently taken in the past several CEMA review proceedings. In the CEMA review proceedings, Cal Advocates and TURN have argued that recovery of CEMA ST labor costs should be disallowed because labor costs for existing staff who respond to CEMA events are recovered in the GRC. This argument suggests that the GRC is the appropriate proceeding for consideration of these costs on a forecast basis. But now, when PG&E has forecast those costs in the GRC and requested a two-way balancing account to record actual costs, Cal Advocates and TURN argue incongruently that CEMA ST labor cannot be recovered in the GRC and can only be recovered in the CEMA.¹⁹²⁰

Cal Advocates and TURN cannot have it both ways. Otherwise, Cal Advocates and TURN will have constructed a regulatory Catch-22 where: (1) PG&E cannot recover CEMA ST labor costs in a CEMA proceeding because according to them, the costs are already recovered in

¹⁹¹⁹ PG&E-04, p. 6-24, line 1 to p. 6-27, line 14, Section F.2.

¹⁹²⁰ CALPA-04, p. 16, line 18 to p. 19, line 15; TURN-12, p. 6, lines 16-18.

the GRC; but (2) PG&E is prohibited from fully forecasting CEMA ST labor in the GRC because the costs can only be recovered in a CEMA proceeding. The Commission should reject one of Cal Advocates' and TURN's arguments in order to resolve this Catch 22. The Commission can do this by either: (1) adopting PG&E's forecast and authorizing the CESTBLA, or (2) explicitly rejecting Cal Advocates' and TURN's assertion that the GRC fully funds existing staff who respond to a CEMA event.

PG&E is generally indifferent to either approach. But what cannot persist is the unfounded notion that PG&E's GRC forecast includes funding for CEMA ST labor, even when CEMA ST labor has been removed from or not authorized in a GRC. Otherwise, PG&E will be inadequately funded for its CEMA response activities.

4.7 Distribution System Operations

PG&E's TY 2023 expense forecast presented in rebuttal testimony is \$58.646 million¹⁹²¹ and is undisputed. PG&E's TY 2023 forecast in the JCE, including the September escalation adjustment, is \$60.531 million.¹⁹²² The expense forecast includes work tracked in the three MWCs: Electric Distribution Operation Activities (MWC BA); Customer Field Service Work (MWC DD); and Distribution Operational Technology (MWC HG).

PG&E's capital expenditures forecast presented in rebuttal testimony is \$4.129 million in 2021, \$4.219 million in 2022, \$4.333 million in 2023, \$2.225 million in 2024, \$2.285 million in 2025, and \$2.347 million in 2026.¹⁹²³ PG&E's capital expenditures forecast, including the September escalation adjustment, is \$4.255 million in 2021, \$4.899 million in 2022, and \$5.243 million in 2023, \$2.696 million in 2024, \$2.733 million in 2025, and \$2.771 million in 2026.¹⁹²⁴

¹⁹²¹ PG&E-17, p. 2-4, Table 2-1, line 9.

¹⁹²² PG&E-64, p. 3-2, Table 3A-1, lines 61-63.

¹⁹²³ PG&E-17, p. 2-5, Table 2-2, line 7 (2021); p. 2-6, Table 2-3, line 7 (2022); p. 2-7, Table 2-4, line 7 (2023).

¹⁹²⁴ PG&E-67, WP-2, lines "[Exhibit 4, Chapter] 7," MWCs 63 and 2F.

PG&E's capital work is tracked in MWC 63, Distribution Operation Technology. PG&E's capital forecast is also undisputed. See Appendix A.

4.8 Field Metering

PG&E's TY 2023 expense forecast presented in rebuttal testimony is \$21.574 million.¹⁹²⁵ PG&E's TY 2023 forecast in the JCE, including the September escalation adjustment, is \$23.161 million.¹⁹²⁶ PG&E's expense forecast is tracked in five MWCs; four of these are uncontested – Read and Investigate Meters (MWC AR); Provide Field Services (MWC DD); Change/Maintain Used Electric Meters (MWC EY); and Change/Maintain Used Gas Meters (MWC HY). See Appendix A. TURN recommends a reduction to Collect Revenue (MWC IU), which is discussed below

PG&E capital expenditures forecast presented in rebuttal testimony is \$81.108 million in 2021, \$86.211 million in 2022, \$104.455 million in 2023, \$115.290 million in 2024, \$95.568 million in 2025, and \$76.414 million in 2026.¹⁹²⁷ PG&E's capital expenditures forecast, including the September escalation adjustment, is \$83.595 million in 2021, \$98.063 million in 2022, and \$123.978 million in 2023, \$138.360 million in 2024, \$113.523 million in 2025, and \$89.043 million in 2026.¹⁹²⁸ Capital work is tracked in two MWCs, Install New Electric Meters (MWC 25) and Install New Gas Meters (MWC 74). Cal Advocates and TURN recommend reductions to MWC 74, which are discussed below. Cal Advocates also recommends an adjustment to PG&E's 2021 forecast for MWC 25; this recommendation is addressed in Appendix A

¹⁹²⁵ PG&E-17, p. 8-2, Table 8-1, line 6.

¹⁹²⁶ PG&E-64, p. 3-2, Table 3A-1, lines 64-68.

¹⁹²⁷ PG&E-17, p. 8-9, Table 8-5, line 3.

¹⁹²⁸ PG&E-67, WP-2, lines "[Exhibit 4, Chapter] 8," MWCs 25, 74 and 3J.

4.8.1 Collect Revenue (MWC IU)

MWC IU includes the field employees, systems, and staff support necessary to effectively perform activities focused on the detection, investigation, and resolution of customer energy theft.¹⁹²⁹ TURN disputes PG&E's forecast and recommends the following reductions:

**TABLE 4-12:
COLLECT REVENUE - PG&E'S EXPENSE FORECAST AND
PARTIES RECOMMENDED REDUCTIONS (\$000s)^(a)**

Party	2020 Rec.	2021	2022	2023
PG&E	\$1,499	\$1,500	\$1,570	\$2,250
TURN				\$(670)
(a) PG&E-17, p. 8-9, Table 8-4, line 5; p. 8-2, Table 8-1, line 5.				

TURN argues that PG&E did not provide support for a 53 percent increase in this area between 2020 recorded and the 2023 forecast. TURN claims that PG&E projects an increase for field employees necessary to support energy theft investigations but does not provide any reasons why energy theft investigations are likely to increase. TURN recommends using PG&E's 2021 forecast plus escalation for the 2023 forecast.¹⁹³⁰

The Commission should not adopt TURN's recommendation. PG&E's recorded costs for 2020 and 2021 do not accurately represent the need for energy theft investigations or PG&E's capacity to conduct them. PG&E explained in rebuttal that its recent spending in MWC IU has been relatively low because of attrition during a three-year transition from non-represented technical employees to an IBEW union represented workforce and because of a COVID-19 related moratorium on Shut-Off for Non-Payment (SONP) field activity. PG&E's energy theft investigations will increase significantly once the SONP moratorium expires in late 2022.¹⁹³¹ In addition, in response to a question at hearings about why PG&E expects energy theft investigations to rise above pre-pandemic levels, PG&E's witness Craig Kurtz noted that "when

¹⁹²⁹ PG&E-04, p. 8-8, line 22 to p. 8-9, line 3.

¹⁹³⁰ TURN-15, p. 2, line 16 to p. 3, line 13.

¹⁹³¹ PG&E-17, p. 8-5, lines 1-21.

we restructured the organization and modified the job duties associated with the revenue assurance investigators, we also modernized the work process flow so that they could be dispatched to investigations in the field, which will increase our ability to work cases in higher volumes than we ever have before.”¹⁹³²

The funding level recommended by TURN will not allow PG&E to execute the number of energy theft investigations required based on its customer population and case backlog. This would be detrimental because, as PG&E described in rebuttal, energy theft creates safety risks to the public and can financially impact customers.¹⁹³³

4.8.2 Install New Gas Meters (MWC 74)

MWC 74 funding includes the labor and support costs necessary to perform gas AMI module installations, exchanges, and removals at customer locations. The primary driver is corrective maintenance related to the escalating number of gas AMI modules which have stopped communicating on PG&E’s Gas AMI network. Cal Advocates and TURN dispute PG&E’s forecast and recommend the following reductions:

**TABLE 4-13:
INSTALL NEW GAS METERS - PG&E’S CAPITAL FORECAST AND
PARTIES RECOMMENDED REDUCTIONS (\$000s)^(a)**

Party	2020 Rec.	2021	2022	2023	2024	2025	2026
PG&E	\$18,192	\$53,573	\$57,511	\$74,355	\$83,911	\$62,855	\$42,319
Cal Advocates		\$(38,982)	\$(36,424)	\$(47,091)			
TURN		\$(53,573)	\$(57,511)	\$(74,355)	\$(83,911)	\$(62,855)	\$(42,319)
(a) PG&E-17, p. 8-3, Table 8-2, line 2; p. 8-9, Table 8-5, line 2; p. 8-10, Table 8-6, line 2.							

Cal Advocates proposes that PG&E’s 2021 recorded costs and 2022-2026 forecast costs be reduced by roughly two thirds, arguing that it is unreasonable for customers to be financially

¹⁹³² See Tr. Vol. 10, 1975:12-20, PG&E/Kurtz.

¹⁹³³ PG&E-17, p. 8-5, line 24 to p. 8-6, line 6.

responsible for the entire costs of new replacement of gas AMI modules that have failed (or are likely to fail) before the end of their expected useful lives.¹⁹³⁴

TURN proposes that PG&E be denied any rate recovery for corrective Gas AMI module replacement in 2023-2026 and recommends that PG&E still be required to replace Gas AMI modules that fail during the 2021-2026 period, subject to cost recovery in the next GRC if PG&E can demonstrate that it has no responsibility for the failures and that its costs are reasonable.¹⁹³⁵ TURN also recommends that PG&E and the Commission consider adopting a reduced rate of return in any future proposal regarding the need to replace Gas AMI modules.¹⁹³⁶

The Commission should not adopt Cal Advocates' proposed forecast reductions or TURN's recommendations for denial or postponement of rate recovery for corrective Gas AMI module replacement because: 1) work activities in this MWC also support both the new installation and removal of gas AMI modules at customer locations, 2) ensuring accurate billing for our customers is an important and essential utility service, and 3) as discussed below in detail in Section 6.10 of this brief, PG&E has consistently demonstrated diligent management of, and always acted prudently with respect to, its Gas AMI Module program.

4.9 Vegetation Management

PG&E's TY 2023 expense forecast presented in rebuttal testimony is \$1,059.072 million and attrition year forecasts are \$1,032.714 million in 2024, \$983,475 million in 2025, and \$900,178 million in 2026.¹⁹³⁷ PG&E's TY 2023 forecast in the JCE, including the September escalation adjustment, is \$1,310.523 million.¹⁹³⁸ PG&E tracks Vegetation Management work

¹⁹³⁴ PG&E-17, p. 8-6, lines 18-28.

¹⁹³⁵ TURN-13, p. 12, line 16 to p. 13, line 5.

¹⁹³⁶ TURN-13, p. 13, lines 13-15.

¹⁹³⁷ PG&E-17, p. 9-17, Table 9-2, line 4.

¹⁹³⁸ PG&E-64, p. 3-2, Table 3A-1, lines 69-70.

in MWC HN (Routine Vegetation Management), MAT IGJ (Enhanced Vegetation Management) and MAT IGI (Tree Mortality Work).

Cal Advocates analyzed and made its recommendations based on PG&E's June 30, 2021 forecast instead of PG&E's final February 25, 2022 forecast. These two forecasts differ significantly in terms of both total dollars forecast and the allocation of work between Routine VM and Enhanced VM. PG&E addresses Cal Advocates' recommended funding level in aggregate because its recommendations for specific programs do not make sense in the context of PG&E's final forecast. Cal Advocates' total recommended funding level for all VM activities in this chapter is \$924.1 million, \$135 million less than PG&E's February 25, 2022 forecast.

4.9.1 Vegetation Management (MWCs HN and IG)

PG&E's Routine VM program is based on an annual patrol of all PG&E distribution lines to support compliance with the CPUC's GO 95 Rule 35, and California Public Resources Code Sections 4292 and 4293.¹⁹³⁹ The Enhanced VM Program is targeted at reducing vegetation contact with overhead distribution lines and other PG&E electric equipment in Tier 2 and Tier 3 HFTDs to reduce the possibility of wildfire ignitions and/or downed wires and outages due to vegetation -conductor contact.¹⁹⁴⁰ PG&E's TY 2023 expense forecast presented in rebuttal testimony is \$1,059.072 million and attrition year forecasts are \$1,032.714 million in 2024, \$983.475 million in 2025, and \$900.178 million in 2026.¹⁹⁴¹ PG&E's TY 2023 forecast in the JCE, including the September escalation adjustment, is \$1,310.523 million.¹⁹⁴² PG&E tracks Vegetation Management work in MWC HN (Routine Vegetation Management), MAT IGJ (Enhanced Vegetation Management) and MAT IGI (Tree Mortality Work).

¹⁹³⁹ PG&E-17, p. 9-5, lines 7-9.

¹⁹⁴⁰ PG&E-04, p. 9-3, lines 11-16.

¹⁹⁴¹ PG&E-17, p. 9-17, Table 9-2, line 4.

¹⁹⁴² PG&E-64, p. 3-2, Table 3A-1, lines 69-70. Attrition year forecasts including the September 6, 2022 escalation adjustment are not available.

On October 31, 2022, PG&E filed a 90-Day Report concerning its Corrective Action Plan in the Enhanced Oversight and Enforcement Process pursuant to Commission Resolution M-4852.¹⁹⁴³ The report provides an overview of PG&E's 2023 plans for its Vegetation Management program, which include a restructuring of the program based on a risk-informed approach for our portfolio of wildfire mitigations including considering Risk Spend Efficiency. Based on recent data and analysis, the risk reduction of the Enhanced VM program is lower than the risk reduction from the EPSS program that was introduced in 2021 and additional operational mitigations such as Partial Voltage capabilities. Additionally, while PG&E's Enhanced VM program has reduced wildfire risk, it has experienced landowner refusals. As a result, PG&E's current plan is to sunset the Enhanced VM program at the end of 2022. PG&E will continue, and enhance, our other existing Vegetation Management programs. PG&E does not expect the overall effect of these program changes will change the amount of funding it needs for Vegetation Management. In any event, to the extent PG&E spends less than its forecast for Vegetation Management in the 2023 GRC period, the difference between the forecast and PG&E's recorded amount will be returned to customers through the VMBA. Cal Advocates disputes PG&E's forecast for Vegetation Management and recommends the following reductions:

**TABLE 4-14:
VEGETATION MANAGEMENT - PG&E'S EXPENSE FORECAST AND PARTIES
RECOMMENDED (REDUCTIONS)/INCREASES (\$000s)^(a)**

Party	2020 Rec.	2021	2022	2023	2024	2025	2026
PG&E Routine VM	\$693,149	\$668,123	\$711,007	\$871,220	\$844,736	\$800,294	\$727,548
PG&E Enhanced VM	\$451,390	\$535,952	916,600	\$118,022	\$117,555	\$112,177	\$102,234
PG&E Tree Mortality	\$93,070	\$67,978	144,000	\$69,830	\$70,423	\$71,003	\$70,396
PG&E Total VM	\$1,237,610	\$1,272,053	1,771,608	\$1,059,072	\$1,032,714	\$983,475	\$900,178
Cal Adv Routine VM				\$(427,316)			
Cal Adv Enhanced VM				\$292,327			

¹⁹⁴³ I.19-09-016/R.18-10-007, PG&E's Enhanced Oversight and Enforcement Process Corrective Action Plan 90-Day Report Pursuant to Resolution M-4852 (Oct. 31, 2022).

Party	2020 Rec.	2021	2022	2023	2024	2025	2026
Cal Adv Tree Mortality				\$--			
Cal Adv Total VM				\$(134,988)			
(a) PG&E-17, p. 9-3, Table 9-1, lines 1-4; p. 9-17, Table 9-2, lines 1-4.							

Cal Advocates recommends reducing PG&E’s Routine and Enhanced VM forecasts¹⁹⁴⁴ for two reasons. First, Cal Advocates proposes forecasting costs based on a three-year (2018-2020) average instead of 2020 recorded costs.¹⁹⁴⁵ Cal Advocates argues that a three-year average is appropriate due to the variability and uncertainty of Routine VM expense each year and that PG&E’s reliance on 2020 recorded adjusted expenses alone inflates its TY 2023 forecast due to significantly higher costs in 2020.¹⁹⁴⁶ Second, Cal Advocates recommends removing certain costs related to Safety Oversight, Quality Verification and Quality Control from PG&E’s forecast.¹⁹⁴⁷ These proposals should be rejected.

First, Cal Advocates’ proposed use of a 2018-2020 average fails to account for costs related to SB 247, which significantly increased PG&E’s labor costs for both Routine and Enhanced VM beginning in 2020. SB 247 established qualifications for line clearance tree trimmers and required that they be paid no less than the prevailing wage for a first period apprentice electrical utility lineman.¹⁹⁴⁸ PG&E estimates that the SB 247 impact increased its costs by approximately 49 percent.¹⁹⁴⁹ PG&E’s 2018 and 2019 recorded costs do not account for the costs required to comply with this new legislation and, therefore, significantly understate

¹⁹⁴⁴ The parties do not dispute PG&E’s Tree Mortality program.

¹⁹⁴⁵ PG&E-17, p. 9-6, lines 4-9.

¹⁹⁴⁶ CALPA-04, p. 23, lines 11-16.

¹⁹⁴⁷ PG&E-17, p. 9-5, line 25 to p. 9-6, line 2.

¹⁹⁴⁸ PG&E-17, PG&E’s response to Data Request CalAdvocates_154-Q02, dated 12/7/21, pp. App A-109 to App A-116.

¹⁹⁴⁹ PG&E-17, p. 9-6, lines 22-29.

PG&E's costs for qualified line clearance tree trimmers and other cost elements going forward. PG&E will continue to incur these costs through the 2023 GRC period.¹⁹⁵⁰

Second, Cal Advocates' recommended reductions related to costs for the Contractor Safety Program, Safety Oversight, Quality Verification, and Quality Assurance for both Routine and Enhance VM are also inappropriate. Cal Advocates recommends excluding costs for hiring a new safety manager and staff based on the two incorrect assertions: (1) that all hiring costs incurred in 2020 were one-time costs; and (2) that PG&E's staffing levels are not increasing.¹⁹⁵¹ Cal Advocates correctly notes that certain one-time hiring costs for the new safety manager and staff are non-recurring, but fails to recognize that PG&E's forecast is not for those costs, but for the continuing costs to pay the safety management staff.¹⁹⁵² In terms of staffing levels, safety management staff in 2020 ranged from 50-75 contract employees whereas PG&E's 2023 forecast includes 70 in-house safety management staff.¹⁹⁵³ Importantly, these in-house safety management employees will be paid more than the contract workers they are replacing.¹⁹⁵⁴ PG&E believes that it is reasonable to bring these resources in-house to: address high contractor turn-over that can negatively impact the consistency of contractors' training, experience and work quality; improve the stability of the safety oversight team; ensure quality control management of this critical workforce; more easily screen applicants for appropriate

1950 As part of its analysis, Cal Advocates mistakenly claims that PG&E's Routine VM forecast for 2023 includes almost 200,000 fewer trees than were worked in 2020. *See* CALPA-04, p. 24, lines 17-19. Cal Advocates is referring to the number of trees forecast in PG&E's June 30, 2021 GRC testimony. In its February 25, 2022 GRC testimony update, PG&E forecasted 1.546 million trees in 2023, only 13,000 fewer trees than the 2020 recorded number of 1.560 million trees. *See* PG&E-04, WP 9-14, Table 9-14, lines 13 and 16.

1951 CALPA-04, p. 26, lines 13-15.

1952 PG&E-17, p. 9-8, lines 2-11.

1953 PG&E-17, p. 9-8, lines 13-22.

1954 PG&E-17, p. 9-8, lines 23-28.

levels of education and experience; and make it easier to identify and act on performance issues.¹⁹⁵⁵

In addition to the issues identified above, it is not appropriate to compare PG&E's 2023 forecast costs for the Contractor Safety Program, Safety Oversight, Quality Verification, and Quality Assurance programs to 2018-2020 recorded costs because the Safety and Quality Verification programs did not even exist in 2018 and 2019, and because labor costs for these activities will increase due to the impacts of SB 247 and a letter agreement that PG&E signed in 2021 with the IBEW converting PG&E non-union vegetation pre-inspector positions to new IBEW union classifications with a higher prevailing wage.¹⁹⁵⁶

4.10 Overhead and Underground Electric Asset Inspections

PG&E's electric distribution facilities are located throughout a large and geographically diverse service territory and include 81,000 miles of electric overhead distribution lines and approximately 26,000 miles of electric underground distribution lines. PG&E's inspection program is a key control in allowing PG&E to keep its complex electric distribution system operating safely and reliably, as well as to mitigate wildfire risk.¹⁹⁵⁷ Under this program, PG&E regularly inspects its overhead and underground electric facilities, in compliance with GO 165 and PG&E's internal standards, to identify areas of deterioration and degradation (as well as issues caused by outside forces and third-party encroachments) that could create unsafe conditions, outages, or wildfires.¹⁹⁵⁸ PG&E's opening testimony more fully describes our planned inspection programs for the 2023 GRC period.

A comprehensive and proactive inspection program is foundational to maintaining a safe and reliable electric system. The funding requested in this GRC is necessary to fund PG&E's

¹⁹⁵⁵ PG&E-17, p. 9-9, lines 18-25.

¹⁹⁵⁶ PG&E-17, p. 9-9, lines 4-15.

¹⁹⁵⁷ PG&E-04, p. 10-1, lines 24-25; p. 10-3, lines 7-10.

¹⁹⁵⁸ PG&E-04, p. 10-1, lines 25-31; p. 10-4, lines 27-33; p. 10-5, lines 15-21.

Electric Asset Inspection Program, which is made up of 12 associated inspection activities (i.e., PG&E uses twelve MATs to record costs).¹⁹⁵⁹ PG&E's TY 2023 expense forecast presented in rebuttal testimony is \$89.464 million.¹⁹⁶⁰ PG&E's TY 2023 forecast presented in the JCE, including the September escalation adjustment, is \$106.340 million.¹⁹⁶¹ The expense forecast includes work tracked in MWC BF (Overhead (OH) and Underground (UG) Inspections and Patrols). PG&E records costs in twelve MATs within MWC BF, of which only one MAT is contested (MAT BFB – Overhead Inspections). There is no capital forecast associated with PG&E's OH and UG inspection activities.

The funding requested in this GRC is necessary for the activities in PG&E's Electric Asset Inspection Program. TURN recommends disallowing costs for one of these activities (Field Safety Reassessments (FSRs), recorded to MAT BFB), asserting that PG&E's past inspection failures increased the number of FSRs that needed to be completed. As explained more fully below, this is not true. But regardless, it does not make sense to limit funding for PG&E's inspection activities that are central to maintaining safety and reliability of the electric system. Indeed, TURN acknowledges the prudence of the FSR inspection program it seeks to defund.¹⁹⁶²

4.10.1 Overhead Inspections (MAT BFB)

PG&E's Overhead Inspections (MAT BFB) program involves performing detailed inspections of electric distribution overhead assets, wherein inspectors assess system components, structures and equipment through visual observations and/or diagnostic tests to identify and document abnormal conditions that may adversely impact safety or reliability.¹⁹⁶³

¹⁹⁵⁹ PG&E-04, p. 10-1, lines 24-25; p. 10-24, line 5 to p. 10-33, line 26.

¹⁹⁶⁰ PG&E-17, p. 10-3, Table 10-1, line 9.

¹⁹⁶¹ PG&E-64, p. 3-2, Table 3A-1, line 71.

¹⁹⁶² TURN-09, p. 1, line 15.

¹⁹⁶³ PG&E-04, p. 10-24, line 5 to p. 10-27, line 21.

PG&E's expense forecast and TURN's recommended adjustments for Overhead Inspections (MWC BFB) are summarized below.

**TABLE 4-15:
OVERHEAD INSPECTIONS - PG&E'S EXPENSE FORECAST AND PARTIES
RECOMMENDED REDUCTIONS (\$000S)^(A)**

Party	2020 Rec.	2021	2022	2023
PG&E	\$95,032	\$93,351	\$60,535	\$58,807
TURN				\$(9,659)
(a) PG&E-17, p. 10-3, Table 10-1, line 1; p. 10-10, Table 10-2, line 2.				

TURN recommends reducing PG&E's forecast to remove \$9.7 million for FSRs.¹⁹⁶⁴ An FSR is a field check of an open Electric Correction (EC) notification that will not be addressed before its due date.¹⁹⁶⁵ FSRs ensure that the risk posed by the condition documented in the EC notification is monitored and can be reprioritized if necessary to resolve the condition on a more expedited timeline.¹⁹⁶⁶ While TURN acknowledges that FSRs are arguably prudent, they argue that the FSRs are necessary only because PG&E's inspection practices prior to the Wildfire Safety Inspection Program (WSIP) were allegedly inadequate.¹⁹⁶⁷ TURN speculates that pre-WSIP inspections failures by PG&E led to an unprecedented number of EC notifications under the new WSIP program, and that if the pre-WSIP inspections had been properly performed in prior years, PG&E would not have a backlog of open EC notifications requiring FSRs.¹⁹⁶⁸ In support of these claims, TURN contends that PG&E's pre-WSIP and WSIP activities are indistinguishable, and that if PG&E identified notifications under WSIP, PG&E should have identified those same notifications sooner in its pre-WSIP program and avoided a backlog.¹⁹⁶⁹

¹⁹⁶⁴ TURN-09, p. 29, lines 3-4.

¹⁹⁶⁵ PG&E-04, p. 10-26, lines 7-9.

¹⁹⁶⁶ PG&E-04, p. 10-26, lines 15-18.

¹⁹⁶⁷ TURN-09, p. 4, lines 13-20;e p. 5, lines 3-5.

¹⁹⁶⁸ TURN-09, p. 4, lines 16-20;e p. 29, lines 6-10.

¹⁹⁶⁹ TURN-09, p. 4, lines 11-12; p. 5, lines 3-4.

TURN's contentions are wrong, and its recommendation to disallow FSR costs is unwarranted. The FSRs are a necessary activity to ensure that pending EC notifications have not further degraded to a condition that requires more immediate action.

In opening testimony, PG&E explained the critical differences between pre-WSIP and WSIP activities, including the reasons for program changes to address wildfire risk. PG&E's pre-2019 inspections were primarily focused on the identification, assessment, prioritization, and documentation of abnormal conditions that negatively impacted safety or reliability.¹⁹⁷⁰ PG&E utilized time-driven cycles to prescribe patrol and inspection activities, and inspectors documented patrols and inspections on a paper map by highlighting completed assets.¹⁹⁷¹ In 2019, PG&E established the WSIP to proactively expand inspections of poles and associated equipment in HFTD areas on an accelerated and enhanced basis to mitigate the risk of initiating fires.¹⁹⁷² Thus, wildfire mitigation became a key focus of the program.

To meet this objective, the WSIP utilizes a risk-informed approach to proactively identify and address potential sources of wildfire ignition, in contrast to the prior practice of time-driven inspection cycles.¹⁹⁷³ Additionally, PG&E began conducting patrols and inspections in HFTD areas more frequently than the minimum requirements of GO 165, and documenting those patrols and inspections using digital records and photos (using electronic tablets) as opposed to paper records.¹⁹⁷⁴ Further, PG&E identified three other critical changes between WSIP and pre-WSIP inspections: (1) an increased time-horizon (look-ahead period) for inspections; (2) stricter inspection criteria and a focus on wildfire risk; and (3) a new WSIP checklist.¹⁹⁷⁵

¹⁹⁷⁰ PG&E-04, p. 10-5, lines 4-6.

¹⁹⁷¹ PG&E-04, p. 10-5, lines 6-8.

¹⁹⁷² PG&E-04, p. 10-5, lines 15-18.

¹⁹⁷³ PG&E-04, p. 10-5, lines 18-21.

¹⁹⁷⁴ PG&E-04, p. 10-5, lines 24-26; p. 10-9, lines 11-16.

¹⁹⁷⁵ PG&E-17, p. 10-6, lines 1-5.

Contrary to TURN's characterization, the increased number of EC notifications identified under the WSIP was not due to prior inspection failures.

First, as a threshold matter, the pre-WSIP inspections met GO 165 requirements. TURN cites to the Independent Federal Monitor Report (November 2021) as evidence of prior pre-WSIP shortcomings, but this report pertains to 2021 activities and identifies various areas in which PG&E's gas and electric operations could improve.¹⁹⁷⁶ PG&E acknowledges the importance of improving its operations, but the report is not evidence that there were substantial pre-WSIP inspection failures warranting a reduction in FSR funding.

Second, PG&E explained in rebuttal testimony that the increased number of EC notifications was due primarily to PG&E's prudent decision to increase the inspectors' time horizon for assessing abnormal conditions that could cause a catastrophic wildfire.¹⁹⁷⁷ Pre-WSIP inspections utilized a one-year time horizon and focused on general safety and reliability issues. Under WSIP, PG&E changed to a five-year time horizon, focused on mitigating wildfire risk, and used stricter criteria, meaning inspectors were instructed to identify any abnormal wildfire-risk conditions that could require maintenance within five years.¹⁹⁷⁸ These changes increased the number of abnormal conditions identified, allowing PG&E to address emerging problems sooner in order to effectively mitigate wildfire risk.¹⁹⁷⁹

TURN does not acknowledge the wildfire-risk reductions achieved under WSIP and is dismissive of PG&E's claim that the change in the inspection time-horizon and stricter emphasis on wildfire risk increased the EC notification rate, suggesting that a five-year look ahead and wildfire focus is indistinguishable from a one-year window and safety/reliability focus.¹⁹⁸⁰ But

¹⁹⁷⁶ TURN-09, p. 24, lines 9-11.

¹⁹⁷⁷ PG&E-17, p. 10-7, lines 3-13.

¹⁹⁷⁸ PG&E-17, p. 10-6, lines 1-20.

¹⁹⁷⁹ PG&E-17, p. 10-7, lines 3-13.

¹⁹⁸⁰ TURN-09, p. 7, lines 11-12.

TURN's witness, an economist not an engineer, offers no technical analysis to support that contention except for noting various similarities between pre-WSIP and WSIP activities.¹⁹⁸¹ That there are similarities between the two programs should not be surprising, and PG&E has never contended there were none.

More critically, TURN does not acknowledge the significance of the differences and changes made to enhance WSIP activities discussed above. TURN's contention otherwise also is illogical. No different than any other type of inspection of a physical component – whether for cars, airplanes, or electrical components – if an inspector considers the suitability and safety of a component over a longer time horizon and applies stricter criteria when completing an inspection (e.g., considering whether an automobile tire will last 10,000 miles versus 20,000 miles and requiring deeper tread depth when making the analysis), the inspector will necessarily identify more components as requiring maintenance, replacement, or additional assessment within that longer time horizon. But this does not mean prior inspections were inadequate; it only means that the current inspections are more rigorous.

The Commission should reject TURN's recommendations to remove FSR costs from PG&E's overhead inspection forecast. The longer inspection time horizon and wildfire-risk focus under WSIP is reasonable given the danger wildfire poses and supports California state and Commission policy for utilities to proactively mitigate wildfire risk.¹⁹⁸² In turn, an FSR provides the visibility necessary to monitor identified tags and system conditions and serves as a reasonable and comparatively low-cost control to ensure correct prioritization of pending EC

¹⁹⁸¹ TURN-09-Atch1, Attachment 1 (Witness Qualifications). TURN's witness is a qualified economist, but is not qualified or informed to provide testimony regarding the sufficiency of PG&E's pre-WSIP inspection programs. For example, there is no evidence that TURN's witness reviewed PG&E pre-WSIP inspection records.

¹⁹⁸² Both SB 901 and AB 1054 require PG&E to “construct, maintain, and operate its electrical lines and equipment in a manner that will *minimize* the risk of catastrophic wildfire posed by those electrical lines and equipment.” Pub. Util. Code, § 8386(a) (emphasis added).

notifications in annual work plans. It would be imprudent for PG&E not to monitor asset conditions and prioritize work using the FSR process. Again, TURN acknowledges this.¹⁹⁸³

Not funding an activity that ensures degraded conditions are appropriately monitored/prioritized and that reduces risk does not make sense and is an unsound approach. The Commission should reject TURN's recommendation to not fund FSR costs.

4.11 Overhead and Underground Electric Distribution Maintenance

As discussed in Section 4.10 above, PG&E's overhead and underground inspections program identifies EC notifications (also known as "tags") for degraded or damaged facilities that pose a safety or reliability risk.¹⁹⁸⁴ PG&E's electric distribution maintenance (EDM) program involves correcting those conditions, as well as repairing and replacing other assets on a programmatic basis.¹⁹⁸⁵ PG&E plans and executes the activities in the EDM program to meet the requirements of GO 95 and GO 128, federal regulations and PG&E internal standards.¹⁹⁸⁶ Almost all EDM activities involve facilities which, if they failed, could potentially disrupt or degrade service or pose an injury risk to the public or PG&E workers.¹⁹⁸⁷ There are numerous activities (recorded in various MAT codes) that comprise PG&E's EDM program, all of which are fully discussed in our prepared testimony.¹⁹⁸⁸

Cal Advocates and TURN recommend various forecast reductions based on using cost information that does not reflect current economic and market conditions or PG&E's work plans. In some cases, Cal Advocates' and TURN's recommendations, if adopted, would limit PG&E's ability to perform critical safety- and reliability-related work, including work that mitigates

¹⁹⁸³ TURN-09, p. 1, line 15 (acknowledging that FSRs are arguably prudent).

¹⁹⁸⁴ PG&E-04, p. 10-1, lines 24-29.

¹⁹⁸⁵ PG&E-17, p. 11-9, lines 14-16.

¹⁹⁸⁶ PG&E-17, p. 11-9, lines 17-19.

¹⁹⁸⁷ PG&E-04, p. 11-1, lines 15-17.

¹⁹⁸⁸ PG&E-04, p. 11-22, line 1 to p. 11-37, line 14.

wildfire risk in HFTDs. The funding requested by PG&E in this GRC for EDM activities is necessary to maintain safe and reliable service and should be approved.

In the subsections that follow, PG&E:

1. provides an overview of PG&E's expense and capital forecasts and parties' recommendations;
2. demonstrates that PG&E's forecasted pace of work for capital programs is reasonable;
3. explains that PG&E reasonable forecasted costs based on recent costs;
4. demonstrates that our forecasts for disputed MATs and MWCs are reasonable; and,
5. addresses Cal Advocates' non-financial recommendation regarding RSE scores.

4.11.1 PG&E's Expense and Capital Forecast And Parties' Recommendations

PG&E's TY 2023 expense forecast presented in rebuttal testimony is \$94.985 million.¹⁹⁸⁹ PG&E's TY 2023 forecast in the JCE, including the September escalation adjustment, is \$111.580 million.¹⁹⁹⁰ PG&E's expense forecast is tracked in three MWCs: Overhead Preventive Maintenance and Equipment Repair (MWC KA); Underground Preventive Maintenance and Equipment Repair (MWC KB); and Distribution Line Equipment Overhauls (MWC BK).

PG&E capital expenditures forecast presented in rebuttal testimony is \$473.535 million in 2021, \$328.029 million in 2022, \$344.238 million in 2023, \$370.739 million in 2024, \$380.872 million in 2025, and \$396.023 million in 2026.¹⁹⁹¹ PG&E's capital expenditures forecast, including the September escalation adjustment, is \$488.196 million in 2021, \$357.579 million in 2022, \$388.822 million in 2023, \$433.275 million in 2024, \$446.332 million in 2025,

¹⁹⁸⁹ PG&E-17, p. 11-3, Table 11-1, line 9.

¹⁹⁹⁰ PG&E-64, p. 3-2, Table 3A-1, lines 72-74.

¹⁹⁹¹ PG&E-17, p. 11-38, Table 11-5, line 14.

and \$453.752 million in 2026.¹⁹⁹² Capital work is tracked in two MWCs: Overhead Equipment Replacement (MWC 2A) and Underground Equipment Replacement (MWC 2B).

TURN recommends an expense forecast reduction of \$38.159 million. For PG&E's capital forecast, Cal Advocates recommends reductions of \$103.109 million in 2021, \$91.904 million in 2022, and \$94.103 million in 2023. TURN recommends reductions to PG&E's capital forecast of \$101.083 million in 2022 and \$103.041 million in 2023.

4.11.2 PG&E's Forecasted Pace of Work For Capital Programs Is Reasonable And Achievable

In general, Cal Advocates' recommended capital forecast reductions are based on speculation that PG&E will not meet its forecasted "pace of work" (i.e., number of units forecasted to be completed). Cal Advocates claims that: (1) there is a general trend that PG&E's proposed pace of work is higher because it intends to make up for work deferred to address other wildfire related work in the last GRC cycle; (2) unless PG&E has decreased the work associated with higher risk programs for 2021 to 2023, PG&E may not have the capacity to increase the pace of work in the EDM program and other programs; and (3) PG&E has not provided sufficient justification for all relevant programs to show that PG&E's forecasted pace of work is necessary in spite of continued higher risk work. To account for what it perceives will be the pace of work going forward, Cal Advocates recommends adjusting PG&E's forecasted units for 2021-2023 by using either 2019-2021 or 2018-2020 historical values.¹⁹⁹³

The Commission should reject Cal Advocates' pace-of-work argument for three reasons: (1) limiting maintenance work could increase PG&E's wildfire and other electric system risk; (2) Cal Advocates bases its recommendations on speculation; and (3) PG&E has provided sufficient justification for all relevant programs.

¹⁹⁹² PG&E-67, WP-2, lines "[Exhibit 4, Chapter] 11," MWCs 2A and 2B.

¹⁹⁹³ CALPA-06, p. 20, line 14 to p. 22, line 5.

In regard to increasing system risks, the maintenance work that Cal Advocates recommends limiting is generally considered compliance work, also referred to as “risk control” or “control” work. Controls are an essential element in managing the risk to PG&E’s systems and are meant to maintain the current level of risk.¹⁹⁹⁴ Without an effective maintenance program, the risk to PG&E’s system will increase. An effective maintenance program helps reduce asset risk by correcting identified hazards and degraded conditions.¹⁹⁹⁵ While PG&E has in the past rescheduled some electric distribution maintenance work in order to address wildfire related work, it is inappropriate to apply a wholesale reduction to compliance work forecast in the 2023 GRC based on past work volumes, given the deleterious impact it would have on increasing system risks, both to safety and reliability. It is important for PG&E to maintain a comprehensive maintenance work plan to protect against these risks.

In addition, Cal Advocates’ argument, which is based on conditions that do not exist today, is speculative. Cal Advocates makes its assertions based on its review of the PG&E’s 2021 Risk Spending Accountability Report¹⁹⁹⁶ which is reporting on work completed in 2021 and does not in any way address PG&E’s capacity to do work in TY 2023. In addition, Cal Advocates’ argument that if PG&E does not decrease other wildfire work it will not be able to maintain the pace of work forecast in the GRC is unfounded. PG&E continues to evaluate and align resources to complete work as efficiently as possible. For example, in prior years PG&E has deferred certain work by moving resources to its high priority system hardening program. PG&E has now established an undergrounding PMO¹⁹⁹⁷ staffed with resources that is building a dedicated system hardening team, eliminating the need to move resources away from other

¹⁹⁹⁴ PG&E’s 2020 RAMP Report, A.20-06-012 (June 30, 2020), p. 3-24, lines 3-6.

¹⁹⁹⁵ PG&E’s 2022 Wildfire Mitigation Plan, OEIS Docket #2022-WMP (Feb. 25, 2022), p. 507.

¹⁹⁹⁶ CALPA-06, p. 21, lines 1-7.

¹⁹⁹⁷ PG&E-17, Ch. 4.3, p. 4.3-18, line 21 to p. 4.3-26, line 31, Section C.4.

work to support system hardening.¹⁹⁹⁸ It would be unreasonable to reduce PG&E's forecast based on speculation.

Finally, PG&E provided sufficient justification for its forecast work in testimony, workpapers, and discovery regarding the capital programs at issue, explaining both the importance of the work for safety and reliability and why the forecasted pace of work is necessary.¹⁹⁹⁹ The programs and associated pace of work is reasonable because it is based on regulatory requirements, PG&E standards and guidelines, and risk information and prioritization.²⁰⁰⁰

4.11.3 PG&E Appropriately Forecast Costs Based On Recent Costs

In other instances, Cal Advocates and TURN recommend forecast reductions based on cost information from 2016-2018 or other selective years, whereas PG&E's forecasts are based on or include relevant 2019-2020 cost information. It is not appropriate to base a forecast on inapplicable or selective cost information that does not reflect current market conditions and the work plan presented in the forecast. The more-recent 2019-2020 unit cost data reflects current circumstances and should be used as the basis of the forecast.²⁰⁰¹ Moreover, the work PG&E plans for 2023 and future years will be based on its risk-informed inspections under WSIP since 2019 and is therefore different in scope and magnitude than the time-based inspection and repair/replacement work completed pre-WSIP in 2016-2018.²⁰⁰²

TURN argues that customers should not pay a premium based on 2019-2020 costs for a maintenance backlog that it alleges was caused by prior inspection failures by PG&E.²⁰⁰³

¹⁹⁹⁸ PG&E-17, p. 11-8, lines 18-21.

¹⁹⁹⁹ PG&E-04, Ch. 11 and PG&E-04, WP Ch. 11.

²⁰⁰⁰ PG&E-04, p. 11-38, lines 1-4.

²⁰⁰¹ PG&E-17, p. 11-11, lines 14-17; p. 11-13, lines 20-22.

²⁰⁰² PG&E-17, p. 11-13, lines 20-22.

²⁰⁰³ TURN-09, p. 33, lines 6-10.

TURN's allegation is wrong and misplaced to the extent it seeks to make PG&E responsible for increased costs beyond PG&E's control. There were no widespread prior inspection failures that caused a maintenance backlog. Rather, PG&E reasonably implemented accelerated and enhanced inspections under WSIP in order to address and mitigate wildfire risk, and the funding requested in this GRC is necessary to address hazards and degraded conditions identified during the WSIP inspections.²⁰⁰⁴ Further, it is evident that unit costs have increased due to various external economic and market conditions beyond PG&E's control.

4.11.4 PG&E's Forecasts For Disputed MWCs And MATs Are Reasonable

4.11.4.1 PG&E's Expense Forecast For Overhead Equipment Replacement (MWC KA) Is Reasonable

PG&E's expense forecasts and TURN's recommended adjustments for Overhead Equipment Replacement (MWC KA) are summarized below.

**TABLE 4-16:
OVERHEAD EQUIPMENT REPLACEMENT - PG&E'S EXPENSE FORECAST
AND PARTIES RECOMMENDED REDUCTIONS (\$000s)^(a)**

Party	2020 Rec.	2021	2022	2023
PG&E	\$117,745	\$62,508	\$60,713	\$74,135
TURN				\$(38,159)
(a) PG&E-17, p. 11-3, Table 11-1, lines 1-4; p. 11-37, Table 11-4, lines 1-4.				

TURN recommends reducing PG&E's MAT KAA expense forecast based on using the average recorded unit cost from 2016 to 2018 to forecast expenditures for 2023.²⁰⁰⁵ TURN notes that the unit costs for this program doubled and tripled in 2019 and 2020, respectively, and argues that customers should not pay a premium based on 2019-2020 costs for a maintenance backlog that it alleges was caused by PG&E's prior inspection failures.²⁰⁰⁶

2004 PG&E-17, p. 10-6, line 24 to p. 10-7, line 13.

2005 TURN-09, p. 34, lines 4-7.

2006 TURN-09, p. 33, lines 6-10.

As discussed above, TURN's allegation is wrong and misplaced to the extent it seeks to make PG&E responsible for increased costs beyond PG&E's control. There were no widespread prior inspection failures that caused a maintenance backlog. Further, it is evident that unit costs have increased due to various external economic and market conditions beyond PG&E's control.

Further, as noted in Section 4.10, PG&E initiated the WSIP in response to the 2017 and 2018 wildfires. Under the WSIP, PG&E has performed accelerated and enhanced inspections with the objective of identifying and addressing degraded facilities posing a wildfire risk. As a result of the WSIP inspections, PG&E issued tags at approximately four times the average annual inspection find rate in pre-WSIP years.²⁰⁰⁷ However, contrary to TURN's assertion that this increased find-rate was due to prior inspection failures, the find-rate was due primarily to PG&E's prudent decision to increase the inspectors' time horizon for assessing abnormal conditions that could cause a catastrophic wildfire.²⁰⁰⁸ While the increased find rate has created a maintenance backlog that PG&E intends to address during this GRC cycle, PG&E's decision to apply stricter inspection criteria beyond G.O. 165 requirements was prudent in order to more effectively address wildfire risk caused by climate change. In addressing the backlog so far, PG&E has focused work execution on the highest wildfire risk tags and managed the volume of lower risk tags through other safety controls.²⁰⁰⁹ In short, PG&E's efforts to prioritize wildfire risk reduction are reasonable, and PG&E should not be penalized for changing economic and market conditions that have recently increased unit costs.

²⁰⁰⁷ PG&E-17, p. 11-10, lines 19-21.

²⁰⁰⁸ PG&E-17, p. 10-7, lines 3-13.

²⁰⁰⁹ PG&E's Revision Notice Response, RN-PG&E-022-05, OEIS Docket # 2022-WMP (July 11, 2022).

TURN uses inapposite 2016-2018 unit-cost data²⁰¹⁰ to develop a unit cost forecast of \$839 for this program.²⁰¹¹ It is not reasonable to use 2016-2018 recorded costs as the basis for this forecast. PG&E's unit cost forecast is based on data from 2019 and 2020 that reflects current circumstances. Moreover, the maintenance work that PG&E is forecasting in this GRC is closely aligned to the risk-based inspection and resulting maintenance work completed in 2019 and 2020, and is reflected in PG&E's forecast unit costs.

4.11.4.2 PG&E's Capital Forecast For Overhead Equipment (MWC 2A) Is Reasonable

PG&E uses MWC 2A to record capital expenditures for Overhead Preventive Maintenance and Equipment Repair.²⁰¹² PG&E's capital forecast and Cal Advocates' and TURN's overall recommended forecast reductions for MWC 2A are summarized below.

**TABLE 4-17:
OVERHEAD PREVENTIVE MAINTENANCE - PG&E'S CAPITAL FORECAST
AND PARTIES RECOMMENDED REDUCTIONS (\$000s)^(a)**

Party	2020 Rec.	2021	2022	2023	2024	2025	2026
PG&E	\$305,856	\$416,195	\$267,155	\$280,507	\$305,280	\$310,591	\$323,852
Cal Advocates		\$(90,704)	\$(79,918)	\$(81,370)			
TURN			\$(101,083)	\$(103,041)			

(a) PG&E-17, p. 11-4, Table 11-2, lines 1-10; p. 11-38, Table 11-5, lines 1-10; p. 11-39, Table 11-6, lines 1-10.

Cal Advocates and TURN both recommend forecast reductions for the following MAT within MWC 2A: Overhead Notifications (MAT 2AA).

Cal Advocates recommends forecast reductions for the following six additional MATs within MWC 2A: (1) Bird Safe Installation and Replacement (MAT 2AB); (2) Bird Safe Retrofit (MAT 2AC); (3) Overhead Idle Facilities Removal (MAT 2AF); (4) Overhead Capital Projects (MAT 2AP); (5) Ceramic Post Insulator Replacement (MAT 2AQ); and (6) FAS Overhead Replacement (MAT 2AS).

²⁰¹⁰ TURN-09, p. 34, lines 4-6.

²⁰¹¹ PG&E-04, WP 11-10, Table 11-10, line 17.

²⁰¹² PG&E-04, p. 11-22, lines 5-6.

TURN recommends forecast reductions for one additional MAT within MWC 2A: Non Exempt Surge Arrester Replacement (MAT 2AR).

PG&E address the parties' specific contentions regarding each of these MATs in the subsections below.

4.11.4.2.1 PG&E's Capital Forecast For Overhead Notifications (MAT 2AA) Is Based On Current Expected Costs

MAT 2AA tracks capital repair/replacement work to address overhead maintenance conditions identified by PG&E's inspection program.²⁰¹³ PG&E's capital forecast and Cal Advocates' and TURN's recommended forecast reductions for MAT 2AA are summarized below.

**TABLE 4-18:
OVERHEAD NOTIFICATIONS (MAT 2AA): PG&E'S CAPITAL FORECAST
AND PARTIES RECOMMENDED REDUCTIONS (\$000s)^(a)**

Party	2020 Rec.	2021	2022	2023	2024	2025	2026
PG&E	\$179,951	\$232,990	\$201,316	\$205,363	\$212,044	\$218,717	\$230,716
Cal Advocates		\$(73,820)	\$(70,701)	\$(72,310)			
TURN			\$(84,279)	\$(85,282)			
(a) PG&E-17, p. 11-38, Table 11-5, line 1 (PG&E's 2020-2026 recorded and forecast costs); p. 11-39, Table 11-6, line 1; p. 11-4, Table 11-2, line 1 (Parties' recommendations).							

Both Cal Advocates and TURN recommend forecast reductions based on reducing the average unit costs used to calculate the forecast.²⁰¹⁴ Cal Advocates uses escalated unit costs from 2016-2018, and TURN proposes using average recorded unit cost from 2016 to 2018.²⁰¹⁵ TURN again argues that customers should not pay a premium that allegedly results from PG&E's maintenance backlog.²⁰¹⁶

²⁰¹³ See PG&E-04, Ch. 10, which discusses PG&E electric distribution inspection activities.

²⁰¹⁴ CALPA-06, p. 31, Table 6-12; TURN-09, p. 33, lines 13-15.

²⁰¹⁵ CALPA-06, p. 31, Table 6-12; TURN-09, p. 34, lines 4-7.

²⁰¹⁶ TURN-09, p. 33, lines 9-10.

The Commission should reject Cal Advocates’ and TURN’s adjusted forecasts for the same reasons discussed above in regard to the MAT KAA forecast. Both Cal Advocates and TURN propose forecast reductions based on cost information that does not reflect current market conditions or the planned work. The more-recent 2019-2020 unit cost data used by PG&E reflects current circumstances and is a better basis for the forecast.²⁰¹⁷ Moreover, PG&E’s forecast is aligned to work that was completed in 2019-2020, making these years an appropriate basis for the forecast.²⁰¹⁸

4.11.4.2.2 PG&E’s Capital Forecast For Bird Safe Installation (MAT 2AB) Is Reasonable

MAT 2AB tracks capital modifications to distribution poles in response to a bird incident. It includes retrofit on the pole where the incident occurred and/or adjacent poles.²⁰¹⁹ PG&E’s capital forecast and Cal Advocates’ recommended forecast reductions for MAT 2AB are summarized below.

**TABLE 4-19:
BIRD SAFE INSTALLATIONS (MAT 2AB): PG&E’S CAPITAL FORECAST
AND PARTIES RECOMMENDED REDUCTIONS (\$000s)^(a)**

Party	2020 Rec.	2021	2022	2023	2024	2025	2026
PG&E	\$1,975	\$3,023	\$3,481	\$3,474	\$3,481	\$3,487	\$3,494
Cal Advocates			\$(736)	\$(735)			
(a) PG&E-17, p. 11-38, Table 11-5, line 2 (PG&E’s 2020-2026 recorded and forecast costs); p. 11-39, Table 11-6, line 2; p. 11-4, Table 11-2, line 2 (Cal Advocates’ recommendations).							

Cal Advocates recommends reducing PG&E’s unit-cost forecast by using 2016-2018 data.²⁰²⁰ The Commission should reject this recommendation for similar reasons to those discussed above regarding the use of inapplicable cost information. Cal Advocates proposes using cost information that does not reflect current market conditions and work plans, in contrast

²⁰¹⁷ PG&E-17, p. 11-13, lines 14-15.

²⁰¹⁸ PG&E-17, p. 11-13, lines 16-19.

²⁰¹⁹ PG&E-04, p. 11-30, lines 3-17.

²⁰²⁰ CALPA-06, p. 32, lines 6-8.

to PG&E’s unit-cost forecast based on recorded 2019-2020 costs for similar work.²⁰²¹ The Commission should reject Cal Advocates’ recommendation for MAT 2AB.

4.11.4.2.3 PG&E’s Capital Forecast For Bird Safe Retrofit (MAT 2AC) Is Reasonable

MAT 2AC tracks capital modifications to distribution poles as part of the annual program which requires selecting and retrofitting a minimum of 2,000 poles. Additionally, this program supports PG&E’s commitment made to the US Fish and Wildlife Service to retrofit poles in raptor concentration zones to mitigate bird-related outages.²⁰²² PG&E’s capital forecast and Cal Advocates’ recommended forecast reductions for MAT 2AC are summarized below.

**TABLE 4-20:
BIRD SAFE RETROFIT (MAT 2AC): PG&E’S CAPITAL FORECAST AND
PARTIES RECOMMENDED REDUCTIONS (\$000s)^(a)**

Party	2020 Rec.	2021	2022	2023	2024	2025	2026
PG&E	\$6,003	\$3,432	\$3,626	\$3,615	\$3,927	\$3,938	\$3,949
Cal Advocates		\$(1,572)	\$(1,736)	\$(1,674)			
(a) PG&E-17, p. 11-38, Table 11-5, line 3 (PG&E’s 2020-2026 recorded and forecast costs); p. 11-9, Table 11-6, line 3; p. 11-4, Table 11-2, line 3 (Cal Advocates’ recommendations).							

Cal Advocates recommends reducing the number of TY 2023 forecasted units and the associated unit cost.²⁰²³ To reduce the forecast number of units, Cal Advocates extrapolates 2019-2021 pace-of-work information and asserts that this is an appropriate basis for forecasting future work.²⁰²⁴ Cal Advocates also recommends basing unit costs on 2017-2019 cost information. The Commission should reject these recommendations for reasons similar to those discussed above for other MWC 2A programs.

²⁰²¹ PG&E-17, p. 11-20, lines 9-11.

²⁰²² PG&E-04, p. 11-30, lines 18-28.

²⁰²³ CALPA-06, p. 34, line 1.

²⁰²⁴ CALPA-06, p. 33, lines 10-19.

By reducing the forecast units based on work completed in prior years, Cal Advocates ignored PG&E’s testimony: “PG&E’s 2023 forecast [costs and number of units in 2023] is higher than 2020 recorded costs due to a workplan shift from priority E tags to priority B tags resulting in more tags to be executed in a shorter time frame”²⁰²⁵ Priority B tags are issued when the condition of an asset is of moderate potential impact to safety or reliability and corrective action is required within 3 months from the date the condition is identified. Priority E tags require corrective action within 12 months from the date the condition is identified (or within 6 months if the tag creates a potential fire ignition risk in HFTD Tier 3).²⁰²⁶ Because PG&E is planning to complete more Priority B tags in 2023 – tags that must be completed within 3 months from the date the condition is identified – PG&E will necessarily be completing more work in a given year than it has historically. PG&E also explained that the number of units forecast for TY2023 is based on compliance requirements and risk-based prioritization.²⁰²⁷ It is inappropriate to compare a forecast number of units based on risk prioritization to an average number of units from prior years that were not based on a similar prioritization method. The Commission should reject Cal Advocates’ recommendation for MAT 2AC.

4.11.4.2.4 PG&E’s Capital Forecast For Idle Facilities Removal (MAT 2AF) Is Reasonable

The MAT 2AF program involves removing (decommissioning) distribution infrastructure that is no longer necessary to serve customers.²⁰²⁸ These facilities can pose a safety and wildfire threat to the extent they can inadvertently become energized. PG&E’s capital forecast and Cal Advocates’ recommended forecast reductions for MAT 2AF are summarized below.

²⁰²⁵ PG&E-04, p. 11-30, lines 14-17.

²⁰²⁶ PG&E-04, p. 11-8, lines 1-7.

²⁰²⁷ PG&E-17, PG&E’s response to Data Request Cal Advocates_090-Q04, dated 10/19/21, pp. App A-135 to App A-136.

²⁰²⁸ PG&E-04, p. 11-27, lines 5-15.

**TABLE 4-21:
IDLE FACILITIES REMOVAL (MAT 2AF): PG&E’S CAPITAL FORECAST
AND PARTIES RECOMMENDED REDUCTIONS (\$000s)^(a)**

Party	2020 Rec.	2021	2022	2023	2024	2025	2026
PG&E	\$4,966	\$20,500	\$2,732	\$2,726	\$2,732	\$2,737	\$2,742
Cal Advocates		\$(8,634)	\$(1,152)	\$(1,148)			
(a) PG&E-17, p. 11-38, Table 11-5, line 4 (PG&E’s 2020-2026 recorded and forecast costs); p. 11-9, Table 11-6, line 4; p. 11-4, Table 11-2, line 4 (Cal Advocates’ recommendations).							

Cal Advocates recommends reducing the unit cost for MAT 2AF to the values authorized in the 2020 GRC.²⁰²⁹ Notably, Cal Advocates does not recommend reducing the amount of work forecast. The Commission should reject Cal Advocates’ recommendation because it effectively reduces the amount of work PG&E can complete.²⁰³⁰ Reducing PG&E’s idle facilities removal program would limit critical system hardening efforts in high-risk wildfire areas.²⁰³¹ The Commission should reject Cal Advocates’ recommendation for MAT 2AF.

4.11.4.2.5 PG&E’s Capital Forecast For Non-Wood Streetlights and Equipment With Access Issues (MAT 2AP) Are Reasonable

The Non-Wood Streetlight Replacement program replaces poles installed prior to 2005 that have an unacceptable level of corrosion.²⁰³² The Equipment with Access Issues program involves relocating equipment where line workers have identified hazards in accessing equipment at its current site.²⁰³³ Both programs are tracked and recorded in MAT 2AP. PG&E’s capital forecast and Cal Advocates’ recommended reductions to these MAT 2AP programs are below.

2029 PG&E-04, WP 11-40, Table 11-36, line 9.

2030 PG&E-17, p. 11-23, line 13-16.

2031 PG&E-17, p. 11-23, lines 12-13.

2032 PG&E-04, p. 11-26, line 15 to p. 11-27, line 3.

2033 PG&E-04, WP 11-35, Table 11-31, line 14.

**TABLE 4-22:
NON-WOOD STREETLIGHTS (MAT 2AP): PG&E’S CAPITAL FORECAST
AND PARTIES RECOMMENDED REDUCTIONS (\$000s)^(a)**

Party	2020 Rec.	2021	2022	2023	2024	2025	2026
PG&E	\$481	\$1,943	\$2,243	\$2,243	\$1,943	\$1,943	\$1,943
Cal Advocates		\$(687)	\$(659)	\$(629)			
(a) PG&E-17, p. 11-38, Table 11-5, line 7 (PG&E’s 2020-2026 recorded and forecast costs); p. 11-9, Table 11-6, line 7; p. 11-4, Table 11-2, line 7 (Cal Advocates’ recommendations).							

For the Non-Wood Streetlight Replacement program, Cal Advocates reiterates its objection regarding PG&E’s forecasted pace of work²⁰³⁴ and recommends a funding level equal to the escalated average capital expenditures for 2019-2021.²⁰³⁵ Cal Advocates’ recommended funding levels are inadequate and would compromise PG&E’s safety objectives for program. Indeed, Cal Advocates proposes nearly a 30 percent reduction, which they characterize inaccurately as “virtually no change.”²⁰³⁶ Replacing non-wood poles, however, mitigates a public safety risk of catastrophic streetlight pole failures due to corrosion or damage.²⁰³⁷ Reducing PG&E’s forecast by nearly 30 percent is unreasonable in light of this public safety risk.

In regard to the Equipment With Access Issues program, Cal Advocates recommends authorizing a budget equal to the escalated average of 2016-2018 because PG&E had no program expenditures in 2019 or 2020.²⁰³⁸ If adopted, Cal Advocates’ recommendation would reduce PG&E’s funding by more than half.²⁰³⁹ Cal Advocates speculates that there is no reason for PG&E to expect to have more issues on its system than it did from 2016-2018.²⁰⁴⁰ The

²⁰³⁴ CALPA-06, p. 43, lines 8-10.

²⁰³⁵ CALPA-06, p. 43, lines 13-14.

²⁰³⁶ CALPA-06, p. 43, Table 6-20 (percent change calculated as: $(\$1,028 - \$743) / \$1,028 = 28\%$ and $(\$1,028 - \$763) / \$1,028 = 26\%$); p. 43, lines 6-7.

²⁰³⁷ PG&E-04, WP 11-54.

²⁰³⁸ CALPA-06, p. 41, lines 10-13.

²⁰³⁹ CALPA-06, p. 42, lines 1-3 and Table 6-19.

²⁰⁴⁰ CALPA-06, p. 41, lines 7-8.

Commission should reject this speculative reasoning. PG&E’s forecast is based on anticipated emergent work given known hazards identified by PG&E electrical engineers and planning experts²⁰⁴¹. It is not reasonable to use PG&E’s 2016-2018 work volume rather than PG&E’s current engineering judgment to forecast work for 2023.

4.11.4.2.6 PG&E’s Capital Forecast For Ceramic Post Insulators (MAT 2AQ) Is Reasonable

The MAT 2AQ program replaces Ceramic Post Insulators manufactured prior to 1972.²⁰⁴² PG&E’s capital forecast and Cal Advocates’ recommended reductions for MAT 2AQ are summarized below.

**TABLE 4-23:
CERAMIC POST INSULATORS (MAT 2AQ): PG&E’S CAPITAL FORECAST
AND PARTIES RECOMMENDED REDUCTIONS (\$000s)^(a)**

Party	2020 Rec.	2021	2022	2023	2024	2025	2026
PG&E	\$2,753	\$3,960	\$5,832	\$5,821	\$5,832	\$5,843	\$5,855
Cal Advocates		\$(3,266)	\$(4,758)	\$(4,718)			
(a) PG&E-17, p. 11-38, Table 11-5, line 8 (PG&E’s 2020-2026 recorded and forecast costs); p. 11-9, Table 11-6, line 8; p. 11-4, Table 11-2, line 8 (Cal Advocates’ recommendations)							

Cal Advocates recommends reducing the forecast 2023 pace of work for the program to the 2019-2021 pace of work, resulting in a reduction of approximately 80 percent. The reduction is unwarranted. In rebuttal testimony, PG&E explained that it is increasing the pace of work from 2022-2026 due to its plans to increase replacement activities in the Tier 2/Tier 3 HFTD areas.²⁰⁴³ Adopting Cal Advocates’ proposal to reduce the number of Ceramic Post Insulators replaced by more than 80 percent in 2023 would significantly reduce the risk reduction afforded by this mitigation. The Commission should reject the proposal and adopt PG&E’s forecast for MAT 2AQ.

²⁰⁴¹ PG&E-17, PG&E’s response to Data Request CalAdvocates_028-Q10, dated 9/7/21, p. App A-132.

²⁰⁴² PG&E-04, p. 11-29, line 1 to p. 11-30, line 2.

²⁰⁴³ PG&E-17, PG&E’s response to Data Request Cal Advocates_090_Q04, dated 10/19/21, pp. App A-135 to App A-136.

4.11.4.2.7 PG&E's Capital Forecast For Field Automation System Overhead Replacement (MAT 2AS) Is Reasonable

This program involves capital work identified during field work completed by a single troubleshooter. The work could be replacement or installations of overhead facilities such as electric distribution conductors, components, structures and associated equipment constructed above ground level.²⁰⁴⁴ PG&E's capital forecast and Cal Advocates' recommended reductions for MAT 2AS are summarized below.

TABLE 4-24:
FIELD AUTOMATION SYSTEM OVERHEAD REPLACEMENT (MAT 2AS): PG&E'S CAPITAL FORECAST AND PARTIES RECOMMENDED REDUCTIONS (\$000s)^(a)

Party	2020 Rec.	2021	2022	2023	2024	2025	2026
PG&E	\$221	\$639	\$831	\$830	\$831	\$833	\$835
Cal Advocates			\$(176)	\$(156)			
(a) PG&E-17, p. 11-38, Table 11-5, line 10 (PG&E's 2020-2026 recorded and forecast costs); p. 11-9, Table 11-6, line 10; p. 11-4, Table 11-2, line 10 (Cal Advocates' recommendations).							

Cal Advocates recommends reducing the forecast based on using PG&E's average pace of work from 2017-2019.²⁰⁴⁵ Cal Advocates claims that there is no reason why PG&E should expect to have more issues on its system compared to the historical norm.²⁰⁴⁶

PG&E's forecast is based on PG&E engineers' best estimate about how the system is functioning today.²⁰⁴⁷ To revert to the number of units from prior years, contrary to these system experts' judgment, is unreasonable. The Commission should reject Cal Advocates' recommendation for MAT 2AS.

²⁰⁴⁴ PG&E-04, WP 11-44, Table 11-40, line 3.

²⁰⁴⁵ CALPA-06, p. 42, Table 6-19.

²⁰⁴⁶ CALPA-06, p. 40, line 21 to p. 41, line 3.

²⁰⁴⁷ PG&E-17, p. 11-32, lines 14-16.

4.11.4.2.8 PG&E's Capital Forecast For Surge Arrester Replacement (MAT 2AR) Is Reasonable

This program involves replacing non-exempt surge arresters with exempt surge arresters and corrects abnormal grounding issues where necessary.²⁰⁴⁸ PG&E's capital forecast and TURN's recommended forecast reductions for MAT 2AR are summarized below.

**TABLE 4-25:
SURGE ARRESTER (MAT 2AR): PG&E'S CAPITAL FORECAST AND
PARTIES RECOMMENDED REDUCTIONS (\$000s)^(a)**

Party	2020 Rec.	2021	2022	2023	2024	2025	2026
PG&E	\$63,497	\$88,859	\$16,804	\$17,759	\$35,472	\$36,429	\$37,413
TURN			\$(16,804)	\$(17,759)			
(a) PG&E-17, p. 11-38, Table 11-5, line 9 (PG&E's 2020-2026 recorded and forecast costs); p. 11-4, Table 11-2, line 9; p. 11-39, Table 11-6, line 9 (TURN's recommendations).							

TURN's primary recommendation is to provide no funding for this program.²⁰⁴⁹ TURN further recommends that the Commission order PG&E to record all work in the program to a below-the-line account unless PG&E can show the replacement work is within a HFTD or HFTD buffer area. TURN also recommends the Commission require PG&E to file a Tier 1 advice letter to show the accounting associated with non-exempt surge arrester replacements in HFTD areas and below-the-line treatment of replacements outside HFTD areas.²⁰⁵⁰ If the Commission declines to adopt TURN's primary recommendation, TURN makes the alternative recommendation that the Commission reduce PG&E's forecast by \$10.4 million for 2022 and \$11.0 million for 2023 and order PG&E to track and report activity as in their primary recommendation.²⁰⁵¹ TURN claims that PG&E's forecast should be reduced because: (1) PG&E has already received ratepayer funds for the grounding-correction part of the MAT 2AR program as part of an expense program that was cancelled;²⁰⁵² (2) PG&E is partly

²⁰⁴⁸ PG&E-04, p. 11-27, line 25 to p. 11-28, line 29.

²⁰⁴⁹ TURN-09, p. 30, Table 2.

²⁰⁵⁰ TURN-09, p. 42, lines 4-15.

²⁰⁵¹ TURN-09, p. 42, line 16 to p. 43, line 12.

²⁰⁵² TURN-09, p. 35, lines 3-10.

responsible for the defective grounding;²⁰⁵³ and (3) the replacement of non-exempt surge arresters in non-HFTD areas has little benefit.²⁰⁵⁴ The Commission should reject these arguments for the reasons described below.

First, the fact that PG&E did not spend previous GRC-authorized *expense* funding for the program should not disqualify its *capital* funding request in this GRC. As PG&E explained in its rebuttal testimony in the 2020 GRC when TURN made this same argument, when the scope of the surge arrester program changed from a stand-alone grounding correction program to a combined grounding and replacement program, it became appropriate to capitalize the work.²⁰⁵⁵ As a result, PG&E could not and did not spend the expense amounts authorized in the 2017 GRC for the Surge Arrester Grounding program (MAT KAR) or the new Non-Exempt Surge Arrester Replacement Program (MAT 2AR).²⁰⁵⁶ Changes in spending due to changes in program scope and accounting treatment are a routine part of test-year forecast ratemaking.

Further, due to forecast ratemaking, in some circumstances adopted amounts exceed actual spending and other times actual spending is higher than adopted amounts. It would not be equitable to penalize PG&E for its expense underspending here when it is not credited for expense overspending in this or other years for other programs.

Second, TURN's argument that PG&E was imprudent is also incorrect. PG&E followed Commission guidance from 1974 regarding this grounding work; PG&E should not be penalized in hindsight for following guidance that was reasonably provided by the Commission at that time. TURN is repeating previous arguments it made about PG&E's Surge Arrester Grounding Program in PG&E's 2017 and 2020 GRCs. PG&E provided testimony rebutting these arguments in the 2017 GRC, which PG&E incorporated as part of its rebuttal here (as it did in its 2020

²⁰⁵³ TURN-09, p. 37, lines 4-6.

²⁰⁵⁴ TURN-09, p. 38, lines 13-14.

²⁰⁵⁵ A.18-12-009, HE-20: Exhibit (PG&E-18), p. 6-23, lines 22-25.

²⁰⁵⁶ PG&E-17, p. 11-15, lines 16-19.

GRC).²⁰⁵⁷ As explained in PG&E’s 2017 GRC rebuttal testimony, prior to 1974, when PG&E installed surge arresters and pole-mounted distribution transformers together, it grounded both the arresters and the transformers separately, but connected the two grounds through an isolating gap.²⁰⁵⁸ In 1974, PG&E met with the Commission and proposed eliminating the isolating gap and connecting non-tank-mounted²⁰⁵⁹ surge arresters and transformer neutrals together and grounding them through a single solid connection to the ground (also known as a “common ground”). PG&E sought guidance from the Commission as to whether this proposed change complied with Rule 33.3(b) of GO 95. As documented in a PG&E memorandum memorializing the meeting, the Commission agreed with the proposed change based on its interpretation of Rule 33.3(b) of GO 95.²⁰⁶⁰ In 2006, PG&E sought guidance from the Commission again, in response to an allegation in a lawsuit that PG&E’s use of a common ground violated GO 95. This time Commission staff concluded that common ground installations were not compliant with GO 95, except in certain limited circumstances.²⁰⁶¹

As it did in the 2017 and 2020 GRC, TURN recommends a disallowance of 20% of non-tank mounted grounding work, rather than 100%, “because CPUC staff did support PG&E’s erroneous proposed practices.”²⁰⁶² TURN, however, recommends that 100 percent of PG&E’s

²⁰⁵⁷ A.15-09-001, Exhibit (PG&E-23), p. 6-8, line 11 to p. 6-18, line 8.

²⁰⁵⁸ A.15-09-001, Exhibit (PG&E-23), p. 6-9, lines 12-15.

²⁰⁵⁹ Surge arresters are either tank-mounted (i.e., mounted on the side of transformer tank) or non-tank-mounted (i.e., mounted on a cross-arm or bracket above the transformer). PG&E is not aware of any technical reason to maintain different grounding configurations for tank-mounted vs. non-tank-mounted surge arresters. See A.15-09-001, PG&E’s response to Data Request TURN_069-Q25(f), dated 4/8/16, pp. App A-389 to App A-390.

²⁰⁶⁰ A Commission memo from the same meeting stated that Commission staff “could find nothing in G.O. 95 requiring the spark gap device.” See A.15-09-001, PG&E’s response to Data Request TURN_009-Q03Rev01 and Attachments TURN_009-Q03Atch01 and Atch02, dated 4/6/16, pp. App A-214 to App A-217.

²⁰⁶¹ A.15-09-001, Exhibit (PG&E-23), p. 6-10, lines 11-32.

²⁰⁶² TURN-09, p. 38, lines 11-13.

expenditures for correcting the grounding of tank-mounted surge arresters be recorded below the line and/or removed from rate base on the basis that the Commission's 1974 guidance supposedly only applied to non-tank mounted surge arresters.²⁰⁶³ But, as PG&E explained in testimony, there is no functional difference between tank-mounted and non-tank-mounted surge arrestor from the perspective of grounding.²⁰⁶⁴ Therefore, PG&E reasonably followed the Commission's guidance for both non-tank-mounted and tank-mounted surge arrestors. This was not PG&E making an error in judgment; this was PG&E attempting to ensure its compliance with GO 95 and following Commission guidance. PG&E only went forward with common grounding of surge arresters after receiving an interpretation from Commission staff that Rule 33.3(b) permitted the change. PG&E should not be penalized for following the Commission's guidance regarding Rule 33.3(b).

Finally, TURN's suggestion that replacing non-exempt surge arrestors in non-HFTD areas has little benefit is wrong. Indeed, it is contrary to the findings of California state agencies. Non-exempt surge arresters are a known fire risk, which is why the California Department of Forestry and Fire Protection includes them on the list of equipment subject to PRC § 4292.²⁰⁶⁵ That risk is present on all poles, albeit to a lesser extent outside the HFTD areas.²⁰⁶⁶ Installing exempt surge arresters is a prudent mitigation of the fire risk; when a non-exempt surge arrester fails due to thermal overload, the arrester failure can produce hot particles, including metals, capable of starting a fire in the presence of fuel.²⁰⁶⁷ Vegetation management under poles with non-exempt equipment reduces risk, but it does not eliminate it; for example, wind can blow the

²⁰⁶³ TURN-09, p. 38, lines 4-8.

²⁰⁶⁴ PG&E-17, p. 11-18, lines 16-18.

²⁰⁶⁵ PG&E-17, p. 11-18, lines 25-27.

²⁰⁶⁶ PG&E-17, p. 11-18, lines 27-28.

²⁰⁶⁷ PG&E-17, p. 11-19, lines 1-4.

particles outside the perimeter that is cleared as part of the PRC §4292 compliance requirement.²⁰⁶⁸

What is more, the Commission agreed that the replacement program provides wildfire-risk-mitigation benefits. In adopting the 2020 GRC Settlement Agreement in its final decision on the 2020 GRC, the Commission found that replacing non-exempt surge arresters mitigates fire risk in HFTDs and non-HFTDs.

While not identified as a top risk, replacement of non-exempt surge arresters serves to mitigate fire risk in HFTD and also non-HFTD areas. In this case, we find it prudent to give due regard to the agreement reached by the settling parties to adopt PG&E's proposed capital forecasts for EDM for 2019 and 2020 as the settling parties include both TURN and Cal Advocates.²⁰⁶⁹

The Commission should reject TURN's recommended disallowances as unsupported. TURN has offered no compelling reasons why arguments it raised in the 2017 and 2020 GRCs should not be rejected again. The Commission should adopt PG&E's forecast for Surge Arrester Replacements (MAT 2AR).

4.11.4.3 PG&E's Capital Forecast For Underground Equipment Replacement (MWC 2B) Is Reasonable

PG&E uses MWC 2B to record capital expenditures for underground preventive maintenance. PG&E's capital forecasts and Cal Advocates' recommended adjustments for MWC 2B are summarized below.

**TABLE 4-26:
UNDERGROUND EQUIPMENT REPLACEMENT – PG&E'S CAPITAL FORECAST AND
PARTIES RECOMMENDED REDUCTIONS (\$000s)^(a)**

Party	2020 Rec.	2021	2022	2023	2024	2025	2026
PG&E	\$47,590	\$57,339	\$60,873	\$63,731	\$65,459	\$70,281	\$72,170
Cal Advocates		\$(12,405)	\$(11,986)	\$(12,733)			
(a) PG&E-17, p. 11-4, Table 11-2, lines 1-10; p. 11-38, Table 11-5, lines 1-10; p. 11-39, Table 11-6, lines 1-10.							

²⁰⁶⁸ PG&E-17, p. 11-19, lines 4-7.

²⁰⁶⁹ D.20-12-005, p. 98 (emphasis added).

Cal Advocates recommends forecast reductions for the following programs within PG&E’s capital forecast for MWC 2B: (1) Underground Notifications (MAT 2BA); and (2) Underground Critical Operating Equipment (MAT 2BD). PG&E’s addresses Cal Advocates’ specific contentions below.

4.11.4.3.1 PG&E’s Underground Notifications (MAT 2BA) Capital Forecast Is Reasonable

Work tracked in MAT 2BA improves system reliability and safety, and ensures regulatory compliance, by correcting abnormal maintenance conditions related to PG&E’s underground facilities.²⁰⁷⁰ PG&E’s capital forecast and Cal Advocates’ recommended forecast reductions for MAT 2BA are summarized below.

**TABLE 4-27:
UNDERGROUND NOTIFICATIONS (MAT 2BA): PG&E’S CAPITAL FORECAST AND
PARTIES RECOMMENDED REDUCTIONS (\$000s)^(a)**

Party	2020 Rec.	2021	2022	2023	2024	2025	2026
PG&E	\$37,864	\$46,680	\$46,391	\$47,807	\$49,171	\$53,333	\$54,773
Cal Advocates		\$(11,142)	\$(11,080)	\$(11,402)			
(a) PG&E-17, p. 11-38, Table 11-5, line 11 (PG&E’s 2020-2026 recorded and forecast costs); p. 11-9, Table 11-6, line 11; p. 11-4, Table 11-2, line 11 (Cal Advocates’ recommendations).							

Cal Advocates recommends reducing PG&E’s MAT 2BA forecast based on reducing unit costs by using the average 2016-2018 recorded unit cost to forecast capital expenditures.²⁰⁷¹ As explained in several sections above, it is not appropriate to base a forecast on cost information that does not reflect current market conditions or the work plan presented in the forecast. The 2019-2020 unit-cost data used by PG&E reflects current circumstances and should be used as the basis of the forecast.

As PG&E explained in rebuttal testimony, unit costs for MAT 2BA started increasing in 2018 because of additional work for known regulatory tags (“F Priority”), which were identified

²⁰⁷⁰ PG&E-04, p. 11-33, line 21 to p. 34, line 16.

²⁰⁷¹ CALPA-06, p. 45, lines 17-19.

during the 2014-2017 timeframe to be completed in the 2018-2020 timeframe.²⁰⁷² In addition, forecast work in MAT 2BA for this GRC period includes increasing work on primary enclosures (larger enclosures that contain high-voltage cables), as opposed to secondary enclosures (smaller enclosures that contain low-voltage cables).²⁰⁷³ Primary enclosures require more excavation than secondary enclosures and generally cost more to replace, which contributes to higher average unit costs starting in 2018.²⁰⁷⁴ Accordingly, PG&E's use of more recent 2019-2020 cost information to determine unit costs is reasonable. The Commission should reject Cal Advocates' recommendation for MAT 2BA.

4.11.4.3.2 PG&E's Underground Critical Operating Equipment (MAT 2BD) Capital Forecast Is Reasonable

The Underground Critical Operating Equipment program (Underground COE) is comprised of corrective maintenance of certain defined equipment.²⁰⁷⁵ PG&E's capital forecast and Cal Advocates' recommended reduction for MAT 2BD are summarized below.

**TABLE 4-28:
UNDERGROUND CRITICAL OPERATING EQUIPMENT (MAT 2BD): PG&E'S CAPITAL
FORECAST AND PARTIES RECOMMENDED REDUCTIONS (\$000s)^(a)**

Party	2020 Rec.	2021	2022	2023	2024	2025	2026
PG&E	\$7,579	\$6,573	\$6,354	\$6,926	\$7,113	\$7,305	\$7,502
Cal Advocates		\$(1,263)	\$(906)	\$(1,331)			
(a) PG&E-17, p. 11-38, Table 11-5, line 12 (PG&E's 2020-2026 recorded and forecast costs); p. 11-9, Table 11-6, line 12; p. 11-4, Table 11-2, line 12 (Cal Advocates' recommendations).							

Cal Advocates recommends reducing the MAT 2BD forecast based upon the average volume of work completed in 2018-2020.²⁰⁷⁶ Cal Advocates fails to acknowledge 2020 as an outlier year that should not be included in the averaging methodology. MAT 2BD is comprised

²⁰⁷² PG&E-17, PG&E's response to Data Request TURN_128-Q04, dated 3/4/22, p. App A-139.

²⁰⁷³ PG&E-17, p. 11-33, lines 14-17.

²⁰⁷⁴ PG&E-17, PG&E's response to Data Request TURN_128-Q04, dated 3/4/22, p. App A-139.

²⁰⁷⁵ PG&E-04, p. 11-35, line 23 to p. 11-36, line 11.

²⁰⁷⁶ CALPA-06, p. 47, Table 6-23.

of reliability focused work but has lower priority than other maintenance work. In 2020, as a relatively lower-priority item, MAT 2BD work activities were impacted by COVID-19.²⁰⁷⁷ Including a COVID-impacted 2020 work volume in an average to determine the 2023 unit forecast is inappropriate and results in an understated forecast not reflective of PG&E's work plans.²⁰⁷⁸ Instead, PG&E used a 2018-2019 two-year average of the find rate²⁰⁷⁹ plus additional units for open or pending jobs. Further demonstrating the reasonableness of PG&E's forecast, the 144 units PG&E forecasts in 2023 is similar to the recorded number of units in 2016, 2017 and 2018.²⁰⁸⁰ The Commission should reject Cal Advocates' recommendation for MAT 2BD.

4.11.5 Non-Financial Recommendations Regarding RSE Scores

Cal Advocates recommends that the Commission should require PG&E to provide more granular RSE scores at the individual MAT code program rather than at a mitigation or control code level.²⁰⁸¹ Cal Advocates states that this recommendation should be applied to all relevant MAT codes related to all GRC chapters related to electric distribution infrastructure.²⁰⁸² PG&E addresses this recommendation in Section 2.3.3

4.12 Pole Asset Management

PG&E's electric distribution system includes approximately 2.3 million wood poles.²⁰⁸³ PG&E's Pole Asset Management Program maintains the safety and reliability of wood pole

²⁰⁷⁷ PG&E-17, p. 11-35, line 5.

²⁰⁷⁸ PG&E-17, PG&E's response to Data Request CalAdvocates_028-Q04, dated 8/30/21, pp. App A-129.

²⁰⁷⁹ PG&E-04, p. 11-36, lines 1-3.

²⁰⁸⁰ PG&E-04, WP 11-48, line 12.

²⁰⁸¹ CALPA-06, p. 27, lines 22-24.

²⁰⁸² CALPA-06, p. 28, lines 5-7.

²⁰⁸³ PG&E-04, p. 12-9, lines 27-29.

assets through comprehensive inspection and repair/replacement programs.²⁰⁸⁴ PG&E's prepared testimony more fully describes PG&E's pole asset management plans for the 2023 GRC period.²⁰⁸⁵

Cal Advocates and TURN do not oppose PG&E's Pole Asset Management expense forecast but do recommend various reductions to PG&E's capital forecast for pole replacements. These recommendations, if adopted, would limit funding necessary to replace deteriorated and damaged poles that PG&E identified through WSIP as posing wildfire risk if not replaced.²⁰⁸⁶ As explained further below, the proposed forecast recommendations are not justified, as they generally are based on Cal Advocates' and TURN's incorrect speculation that the volume of poles to be replaced has increased because PG&E has deferred pole-replacement work or failed to properly complete pole inspections in the past. This is not the case. PG&E's deferred work analysis submitted in this GRC demonstrated that there were no deferred pole replacements from the 2020 GRC.²⁰⁸⁷ The increased volume of pole-replacement work is due to stricter criteria under the WSIP in order to mitigate wildfire risk, not prior inspection failures.

In the sections that follow, PG&E: (1) summarizes the expense and capital forecast for Pole Asset Management activities; (2) summarizes parties' recommendations concerning this program; (3) explains why the forecast to install and replace overhead poles is reasonable; and (4) addresses Cal Advocates' non-financial recommendation.

4.12.1 PG&E's Expense and Capital Forecast

PG&E's TY 2023 expense forecast presented in rebuttal testimony is \$39.340 million.²⁰⁸⁸ PG&E's TY 2023 forecast in the JCE, including the September escalation

²⁰⁸⁴ PG&E-04, p. 12-9, line 25 to p. 12-10, line 7.

²⁰⁸⁵ PG&E-04, p. 12-4, line 4 to p. 12-15, line 6.

²⁰⁸⁶ See Section 4.10 for additional information regarding the WSIP.

²⁰⁸⁷ PG&E-04, p. 12-33, lines 8-12.

²⁰⁸⁸ PG&E-17, p. 12-3, Table 12-1, line 6.

adjustment, is \$49.188 million.²⁰⁸⁹ PG&E’s expense forecast is tracked in MWC GA, Poles – Intrusive Inspection/Test and Treat Program, and is uncontested, as indicated in Appendix A.

PG&E capital expenditures forecast presented in rebuttal testimony is \$311.884 million in 2021, \$366.453 million in 2022, \$379.514 million in 2023, \$400.215 million in 2024, \$400.989 million in 2025, and \$402.489 million in 2026.²⁰⁹⁰ PG&E’s capital expenditures forecast including the September escalation adjustment is \$321.540 million in 2021, \$399.466 million in 2022, \$428.667 million in 2023, \$467.723 million in 2024, \$469.907 million in 2025, and \$461.161 million in 2026.²⁰⁹¹ Capital work is tracked in MWC 07, Electric Distribution – Install/Replace Overhead Poles.

4.12.2 PG&E’s Capital Forecast For Install/Replace Overhead Poles (MWC 07) Is Reasonable

PG&E uses MWC 07 to record capital expenditures for Pole Asset Management. PG&E’s capital forecasts and Cal Advocates’ recommended adjustments for MWC 07 are summarized below.

**TABLE 4-29:
INSTALL/REPLACE OVERHEAD POLES - PG&E’S CAPITAL FORECAST
AND PARTIES RECOMMENDED REDUCTIONS (\$000s)^(a)**

Party	2020 Rec.	2021	2022	2023	2024	2025	2026
PG&E	\$249,238	\$311,884	\$366,453	\$379,514	\$400,215	\$400,989	\$402,489
Cal Advocates ^(b)		\$(151,900)	\$(277,390)	\$(31,835)			
TURN			\$(76,660)	\$(79,764)			
(a) PG&E-17, p. 12-4, Table 12-2, line 4; p. 12-14, Table 12-5, line 7; p. 12-15, Table 12-6, line 7. (b) Includes Cal Advocates recommendation to increase 2021 costs by \$0.594 million in MWC 21 – Miscellaneous Capital							

Cal Advocates and TURN both recommend forecast reductions for one MAT in MWC 07: Pole Replacement Program (MAT 07D). Cal Advocates recommends forecast reductions

²⁰⁸⁹ PG&E-64, p. 3-2, Table 3A-1, line 75.

²⁰⁹⁰ PG&E-17, p. 12-14, Table 12-5, line 7.

²⁰⁹¹ PG&E-67, WP 2, line "[Exhibit 4, Chapter] 12," MWC 07.

for two additional MATs in MWC 07: (1) Overloaded Poles (MAT 07O); and (2) Center-Bore Streetlights/Tree Attachments (MAT 07C).

Cal Advocates also recommends increases to the Joint Pole Program (MAT 07G, 07#) and Miscellaneous Capital (MAT21A). PG&E does not dispute Cal Advocates' recommended forecast increase for these three MAT activities: MAT 07G, MAT 07#, and MAT 21A.

PG&E responds below to Cal Advocates' and TURN's recommended forecast reductions for the contested items.

4.12.2.1 PG&E's Forecasts For Pole Replacement Programs (MAT 07D, 07O and 07C) Are Reasonable

Under the Pole Replacement Program, MAT 07D activities involve replacing poles that are identified through PG&E's inspection programs as deteriorated, degraded, or damaged. MAT 07O is used for poles that are identified as potentially overloaded. MAT 07C covers replacements of tree attachments.²⁰⁹² PG&E's capital forecast and Cal Advocates' and TURN's recommended reductions for MAT 07D, 07O, and 07C are summarized below.

**TABLE 4-30:
POLE REPLACEMENT PROGRAMS (MATS 07D, 07O AND 07C): PG&E'S CAPITAL
FORECAST AND PARTIES RECOMMENDED REDUCTIONS (\$000s)^(a)**

Party	2020 Rec.	2021	2022	2023	2024	2025	2026
MAT 07D							
PG&E	\$238,714	\$301,007	\$355,298	\$368,381	\$388,115	\$387,889	\$388,355
Cal Advocates				\$(30,901)			
TURN			\$(76,660)	\$(79,764)			
MAT 07O							
PG&E	\$11,114	\$10,877	\$7,852	\$7,837	\$8,600	\$9,391	\$10,210
Cal Advocates				\$(657)			
MAT 07C							
PG&E	\$87	\$--	\$3,303	\$3,296	\$3,500	\$3,709	\$3,924
Cal Advocates				\$(276)			
Cal Advocates ^(b)		\$(155,605)	\$(227,390)				
Total Forecast	\$249,916	\$311,884	\$366,453	\$379,514			

²⁰⁹² PG&E-17, p. 12-5, lines 13-16.

Party	2020 Rec.	2021	2022	2023	2024	2025	2026
Cal Advocates Total Rec. Reduction		\$(155,605)	\$(227,390)	\$(31,835)			
TURN Total Rec. Reduction			\$(76,660)	\$(79,764)			
(a) PG&E-17, p. 12-14, Table 12-5, lines 1-3 (PG&E's 2020-2026 recorded and forecast costs); p. 12-15, Table 12-6, lines 1 and 4; p. 12-4, Table 12-2, lines 1-3 (Parties' recommendations). (b) Cal Advocates' recommended reductions for 2021 and 2022 are related to PG&E's Pole Replacement Program and are not allocated by MAT.							

Cal Advocates recommends reducing PG&E's capital forecast for the Pole Replacement Program.²⁰⁹³ Cal Advocates suggests that PG&E historically has not adequately inspected and replaced when necessary distribution poles under the Pole Replacement Program,²⁰⁹⁴ and further criticizes PG&E for having a history of deferring needed capital projects that had previously been authorized by the Commission.²⁰⁹⁵ Cal Advocates argues that it is unlikely that PG&E's WSIP identified additional poles that would not have been identified sooner had PG&E inspected them properly in years prior to WSIP.²⁰⁹⁶ Cal Advocates contends that in light of these alleged historical deficiencies, adjustments should be made to the forecast to exclude higher replacement costs that PG&E allegedly could have avoided had the degraded pole conditions been identified years sooner.²⁰⁹⁷ Cal Advocates asserts these higher costs consist of contract workers under increased overtime²⁰⁹⁸ and calculates a proposed exclusion (disallowance) of \$31.8 million.²⁰⁹⁹

TURN proposes a reduction of \$79.8 million to the 2022 and 2023 total-cost forecast for the Pole Replacement Program based on reductions to unit costs, which have increased since

²⁰⁹³ CALPA-05, p. 16, Table 05-3.

²⁰⁹⁴ CALPA-05, p. 35, lines 27-30.

²⁰⁹⁵ CALPA-05, p. 21, lines 8-10.

²⁰⁹⁶ CALPA-05, p. 36, lines 5-9.

²⁰⁹⁷ CALPA-05, p. 36, lines 5-9, p. 36, line 26 to p. 37, line 4.

²⁰⁹⁸ CALPA-05, p. 37, lines 2-4.

²⁰⁹⁹ CALPA-05, p. 16, Table 05-3.

PG&E initiated the WSIP in 2019.²¹⁰⁰ TURN believes there are various premiums attributable to PG&E's accelerated work plans that customers should not have to pay.²¹⁰¹ In calculating the proposed reduction, TURN uses average recorded unit costs from 2016-2017 plus an adjustment for heavy-equipment use.²¹⁰²

4.12.2.1.1 Cal Advocates Ignores PG&E's Efforts To Mitigate Wildfire Risks While Controlling Costs

The Commission should reject Cal Advocates' proposed disallowance. Cal Advocates' contention that imprudent inspections by PG&E caused a higher unit cost is incorrect for two reasons: (1) PG&E was not imprudent in its prior inspections but instead prudently changed its inspection criteria to address increasing wildfire risk; and (2) PG&E ensured it obtained competitive pricing from contractors to complete the work.²¹⁰³

Cal Advocates' criticism of PG&E's historical inspections is similar to TURN's criticism addressed in Section 4.10, above. Like TURN, Cal Advocates reaches a faulty conclusion by incorrectly correlating the current higher volume of pole maintenance items (including pole replacements) with supposed past inspection failures. The correct correlation is that the higher volume of maintenance items is due to PG&E's prudent decision to apply stricter inspection criteria in order to ensure that wildfire risks were being addressed sufficiently. It was critical for PG&E to change inspection criteria as increasing wildfire risk has become apparent following the 2017 and 2018 northern California wildfires. To that end, in 2019, PG&E developed detailed and objective criteria for the GO 165 detailed visual inspections based on the asset wildfire risk analysis that was informed by a Failure Mode and Effects Analysis (FMEA).²¹⁰⁴ The analysis

²¹⁰⁰ PG&E-17, p. 12-8, lines 8-12.

²¹⁰¹ TURN-09, p. 47, lines 4-14.

²¹⁰² TURN-09, p. 50, lines 9-13.

²¹⁰³ PG&E-17, p. 12-6, lines 19-22.

²¹⁰⁴ PG&E-17, p. 12-7, lines 2-5.

identified single points of failure on electric components that could lead to fire ignition.²¹⁰⁵ PG&E used this information to develop enhanced inspection criteria and initiate accelerated inspections of electric facilities in HFTDs to identify and repair non-conforming facilities (including non-conforming poles) that posed an ignition, safety, or reliability risk.²¹⁰⁶ Under the new inspection program (referred to as the Wildfire Safety Inspection Program or WSIP), PG&E is now performing inspections at an accelerated rate and inspecting more assets, including poles, annually than had been inspected in the past.²¹⁰⁷ The new inspection program uses stricter criteria for completing the pole health assessment, resulting in a higher find-rate and increased volume of pole replacements than was historically the case.²¹⁰⁸

In addition, Cal Advocates' assertion that higher unit costs forecast by PG&E were caused by the need to hire additional contractors with increased overtime ignores the meaningful actions PG&E implemented to reduce costs.²¹⁰⁹ PG&E conducted a Request for Proposal (RFP) process with multiple vendors to establish cost-competitive pricing for Distribution and Transmission Overhead and Underground work, which includes pole replacements. The RFP process encourages suppliers to manage their productivity and ensures that PG&E obtains favorable cost terms. The RFP contracts were issued in April 2021 and resulted in significant savings in 2021 that PG&E anticipates will continue forward.²¹¹⁰

Lastly, contrary to Cal Advocates' speculation regarding the reasons for the increased number of pole replacements forecast in this GRC, PG&E has not deferred the count of poles to be replaced in the prior years. As discussed above, the high volume of pole replacements is a

²¹⁰⁵ PG&E-17, p. 12-7, lines 5-6.

²¹⁰⁶ PG&E-17, PG&E's response to Data Request TURN_120-Q02(a), dated 2/28/22, p. App A-142.

²¹⁰⁷ PG&E-17, p. 12-7, lines 11-14.

²¹⁰⁸ PG&E-17, p. 12-7, lines 14-16.

²¹⁰⁹ CALPA-05, p. 36, line 26 to p. 37, line 4.

²¹¹⁰ PG&E-17, PG&E's response to Data Request TURN_120-Q05(a), dated 2/28/22, App A-145.

result of the larger volume of inspections and stricter inspection criteria applied under WSIP, not deferred work from prior years. Indeed, as a required part of PG&E's showing, PG&E's deferred-work analysis did not identify pole replacements as deferred work.²¹¹¹ During cross-examination in evidentiary hearings, PG&E witness, Mr. Arvind Simhadri, confirmed that there was no deferred work contributing to the increased number of required pole replacements.²¹¹²

4.12.2.1.2 TURN's Forecast Is Based On Inapplicable Cost Information And Ignores That Cost Drivers Are Beyond PG&E's Control

The Commission should also reject TURN's recommendation to use 2016-2017 costs to derive the forecast. TURN's proposal seems expressly designed to derive an artificially-lower forecast that ignores current market conditions and work plans.²¹¹³ In contrast, PG&E uses an unbiased forecasting methodology utilizing the last three years of recorded costs (2018–2020) to calculate the capital forecasts for pole replacements.²¹¹⁴ PG&E's use of an averaging methodology is reasonable given that annual costs fluctuate from year to year. More importantly, the three-year average reflects existing market conditions and work plans.²¹¹⁵

Further, the cost increases driving PG&E's unit costs are due to external market factors beyond PG&E's control, including higher labor and non-labor costs, disposal costs, and environmental/permitting costs.²¹¹⁶ The increase of pole replacement costs in recent years can also be attributed to the locations of the pole replacements.²¹¹⁷ PG&E has appropriately prioritized pole replacements in HFTD Tier 2 and Tier 3 areas, where the poles at times are not

²¹¹¹ PG&E-04, p. 2-35, Table 2-5; see also A.18-12-009, HE-16: Exhibit (PG&E-04), p. 1-27, Table 1-4 (noting that pole replacements was not deferred work in the 2020 GRC as well).

²¹¹² Tr. Vol. 7, 1228:8-19, PG&E/Simhadri.

²¹¹³ PG&E-17, p. 12-9, lines 4-6.

²¹¹⁴ PG&E-17, p. 12-9, lines 8-10.

²¹¹⁵ PG&E-17, p. 12-9, lines 17-19.

²¹¹⁶ PG&E-17, p. 12-9, line 23 to p. 12-10, line 2.

²¹¹⁷ PG&E-17, p. 12-10, lines 3-4.

accessible with bucket trucks and require the use of more expensive equipment, including helicopters, large cranes or other heavy equipment, which adds significant cost to those replacements.²¹¹⁸ PG&E expects to continue to replace poles in difficult-to-access locations, which require additional equipment, special permits and safety precautions.²¹¹⁹ In addition, PG&E expects material costs to continue to increase.²¹²⁰ Like Cal Advocates, TURN suggests that PG&E should bear these increases because PG&E's prior actions created a pole-replacement backlog. But, as noted above, there was no deferred work. The current backlog is due to PG&E's prudent wildfire risk management efforts to inspect an increased volume of poles under stricter criteria.

TURN and Cal Advocates ignore all of these factors and propose forecast reductions that would create resource constraints to complete the work. For the reasons discussed above, the Commission should reject Cal Advocates' and TURN's recommended disallowances and approve PG&E's Pole Replacement Program (MAT 07D, 07O and 07C) forecasts with zero disallowances.

4.12.3 Cal Advocates' Non-Financial Recommendations

Cal Advocates recommends that all pole replacement costs that are tracked under the Wildfire Mitigation Plan Memorandum Account (WMPMA) be removed from the capital forecast in MWC 07. Cal Advocates is opposed to including WMPMA-related capital expenditures in ratebase although the poles are used and useful.²¹²¹ PG&E addresses this issue in Section 10.4 of this brief.

²¹¹⁸ PG&E-17, p. 12-10, lines 4-9.

²¹¹⁹ PG&E-17, p. 12-10, lines 9-11.

²¹²⁰ PG&E-17, PG&E's response to Data Request TURN_120-Q10, dated 2/28/22, pp. App A-150 to App A-151.

²¹²¹ CALPA-05, p. 19, lines 12-14.

4.13 Overhead and Underground Asset Management and Reliability

PG&E's Overhead Asset Management (OAM) program involves overhead asset replacement for deteriorated overhead conductor and switches.²¹²² PG&E's Underground Asset Management (UAM) program addresses asset replacement for underground assets, including primary underground distribution cable, switches, vaults, enclosures and conduits.²¹²³ In addition to these asset replacement programs, PG&E implements a Reliability Program that involves adding additional distribution protection device zones or automated switching equipment to reduce or mitigate the number of customers impacted by future outages. The distribution circuit zone reliability improvements are designed to reduce sustained customer interruptions and outage durations, and contribute to public safety.²¹²⁴ The OAM, UAM, and Reliability programs improve the safety and reliability of PG&E's overhead and underground electric distribution system for the benefit of customers. PGE's opening testimony more fully describes the programs PG&E plans for the 2023 GRC period.

Cal Advocates and AARP recommend forecast reductions in these programs. Many of Cal Advocates' recommendations do not dispute that the planned work is necessary, and instead are based on PG&E's prior pace of work when PG&E was resource-constrained while addressing emergent wildfire mitigation work, other higher-priority work, and the COVID-19 pandemic. Cal Advocates' proposed cuts do not reflect current circumstances and PG&E's resource and work plans. They should be denied. AARP argues that overhead conductor replacement is unnecessary in non-HFTDs, but largely ignores other safety and reliability issues. The Commission should reject AARP's recommendations as well.

²¹²² PG&E-04, p. 13-5, lines 23-25.

²¹²³ PG&E-04, p. 13-6, lines 6-9.

²¹²⁴ The circuit zone reliability activities described in this Section are limited to non-HFTD areas only. For details of the circuit zone reliability work performed in HFTD areas, please refer to Chapter 4 of this exhibit.

In the sections that follow, PG&E: (1) summarizes its capital forecasts for the OAM, UAM, and Reliability programs; (2) summarizes parties' recommendations concerning these programs; (3) addresses Cal Advocates' pace of work argument; (4) addresses AARP's proposal not to replace overhead conductor in non-HFTD areas; (5) demonstrates that PG&E's capital forecasts for overhead asset replacement (MWC 08) are reasonable; (6) demonstrates PG&E's forecast for distribution circuit reliability (MWC 49) is reasonable; and (7) demonstrates that PG&E's forecast for underground asset replacement (MWC 56) is reasonable.

4.13.1 PG&E's Capital Forecast

PG&E capital expenditures forecast for the OAM, UAM, and Reliability programs presented in rebuttal testimony is \$153.720 million in 2021, \$145.742 million in 2022, \$164.438 million in 2023, \$167.528 million in 2024, \$171.152 million in 2025, and \$176.895 million in 2026.²¹²⁵ PG&E's capital expenditures forecast presented in the JCE, including the September escalation adjustment, is \$158.479 million in 2021, \$158.871 million in 2022, and \$185.735 million in 2023, \$195.787 million in 2024, \$200.568 million in 2025, and \$202.682 million in 2026.²¹²⁶ Capital work is tracked in three MWCs: Electric Distribution Overhead Asset Replacement (MWC 08); Distribution Circuit Zone Reliability (MWC 49); and Electric Distribution Underground Asset Replacement (MWC 56).

4.13.2 The Commission Should Reject Cal Advocates' Pace-Of-Work Argument

As it does for other portions of PG&E's forecasts (such as overhead and underground maintenance activities discussed in Section 4.11), Cal Advocates continues to speculate that PG&E will not meet the forecasted "pace of work" (i.e., number of units forecasted to be completed) based on trends in prior years and recommends adjusting PG&E's forecasted units for 2021-2023 by using values achieved in prior years. In Section 4.11.2, PG&E showed why

²¹²⁵ PG&E-17, p. 13-28, Table 13-4, line 23.

²¹²⁶ PG&E-67, WP-3, lines "[Exhibit 4, Chapter] 13," MWCs 08, 09, 49, 56, 2A and 2F.

Cal Advocates’ approach should not be adopted. Briefly reiterated here in regard to PG&E asset replacement and reliability programs, the Commission should reject Cal Advocates’ “pace of work” argument because: (1) limiting maintenance work could increase PG&E’s wildfire and other electric system risk; (2) Cal Advocates bases its recommendations on speculation; and (3) PG&E has provided sufficient justification for all relevant programs. If adopted, Cal Advocates’ recommended funding levels would limit PG&E’s ability address various electric reliability and equipment failure risks.

Without an effective replacement program, the risk to PG&E’s system will increase. An effective replacement program helps reduce asset risk by correcting identified hazards, degraded conditions, and non-standard equipment concerns.²¹²⁷ In addition, Cal Advocates’ argument essentially is based on conditions that do not exist today. Cal Advocates makes its assertions based on its review of the PG&E’s 2021 Risk Spending Accountability Report²¹²⁸ which is reporting on work completed in 2021 and does not in any way address PG&E’s capacity to do work in TY 2023. PG&E continues to evaluate and align resources to complete work as efficiently as possible and is eliminating the need to divert resources from its asset replacement and reliability work.²¹²⁹ Finally, PG&E provided sufficient justification for its forecast work in testimony, workpapers, and discovery regarding the capital programs at issue, explaining both the importance of the work for safety and reliability and why the forecasted pace of work is necessary.²¹³⁰

²¹²⁷ PG&E-04, p. 13-19, line 6 to p. 13-25, Table 13-6; PG&E’s 2022 Wildfire Mitigation Plan, OEIS Docket #2022-WMP (Feb. 25, 2022), p. 507.

²¹²⁸ CALPA-06, p. 21, lines 1-7.

²¹²⁹ PG&E-17, p. 13-9, lines 22-23.

²¹³⁰ PG&E-04, Ch. 13; PG&E-04, WP Ch. 13; PG&E-17, p. 11-6, line 22 to p. 11-9, line 8.

4.13.3 The Commission Should Reject AARP’s Recommendations As Counter To Sound And Prudent Utility Practices

AARP questions the cost effectiveness of replacing overhead conductors in non-HFTDs given that the fire risk is low, and suggests that increasing the conductor replacement rate may be unnecessary, at least until wildfire risk spending slows, or until data is collected that indicates preemptive conductor replacement delivers benefits in excess of costs.²¹³¹ In making this recommendation and others like it (see discussion in Section 14.4), AARP appears to embrace a run-to-failure operations strategy that largely ignores safety and reliability issues, including for customers, public, and PG&E workers. This approach to maintaining utility assets is unreasonable and creates safety risks. The Commission should reject AARP’s recommendation that are based on run-to-failure principles.

4.13.4 PG&E’s Capital Forecast For Electric Distribution Overhead Asset Replacement (MWC 08) Is Reasonable

PG&E uses MWC 08 to record capital expenditures for Overhead Asset Management. PG&E’s capital forecasts and Cal Advocates’ and AARP’s recommended adjustments for MWC 08 are summarized below.

**TABLE 4-31:
ELECTRIC DISTRIBUTION OVERHEAD ASSET REPLACEMENT - PG&E’S CAPITAL
FORECAST AND PARTIES RECOMMENDED REDUCTIONS (\$000s)^(a)**

Party	2020 Rec.	2021	2022	2023	2024	2025	2026
PG&E	\$16,595	\$42,105	\$33,637	\$44,011	\$45,487	\$46,729	\$47,990
Cal Advocates		\$(17,185)	\$(16,561)	\$(26,474)			
AARP				\$(28,879)	\$(30,329)	\$(31,544)	\$(32,777)
(a) PG&E-17, p. 13-5, Table 13-1, lines 1-2; p. 13-6, Table 13-2, lines 1-2; p. 13-28, Table 13-4, lines 1-2.							

Cal Advocates and AARP both recommend forecast reductions for one program within PG&E’s capital forecast for Electric Distribution Overhead Asset Replacement: Overhead Conductor Replacement Program (MAT 08J). Cal Advocates recommends forecast reductions for one additional program in MWC 08: Grasshopper/Overhead Switch Replacements (MAT

²¹³¹ AARP-01, p. 51, line 13 to p. 52, line 11.

08S). Cal Advocates’ and AARP’s recommendations regarding these MATs are addressed in the subsections below.

4.13.4.1 PG&E’s Capital Forecast For Overhead Conductor Replacement Program (MAT 08J) Is Reasonable

MAT 08J tracks PG&E’s proactive replacement of overhead conductor in non-HFTD areas to address elevated rates of wires down and deteriorated/damaged conductors, and to improve system safety, reliability, and integrity.²¹³² PG&E’s capital forecast and Cal Advocates’ and AARP’s recommended forecast reductions for MAT 08J are summarized below.

**TABLE 4-32:
OVERHEAD CONDUCTOR REPLACEMENT (MAT 08J) - PG&E’S CAPITAL FORECAST
AND PARTIES RECOMMENDED REDUCTIONS (\$000s)^(a)**

Party	2020 Rec.	2021	2022	2023	2024	2025	2026
PG&E	\$16,591	\$41,180	\$32,688	\$43,036	\$44,486	\$45,701	\$46,934
Cal Advocates		\$(16,626)	\$(15,906)	\$(25,801)			
AARP				\$(28,879)	\$(30,329)	\$(31,544)	\$(32,777)
(a) PG&E-17, p. 13-28, Table 13-4, line 1 (PG&E recorded and forecast costs); p. 13-29, Table 13-5, line 1; p. 13-5, Table 13-1, line 1; p. 13-6, Table 13-1, line 1 (Parties’ recommendations).							

Cal Advocates questions whether PG&E will achieve the pace of work assumed in PG&E’s capital forecast for the Overhead Conductor Replacement Program and argues for forecast reductions based on PG&E’s recent work history.²¹³³ Cal Advocates recommends that the Commission reduce PG&E’s MAT 08J forecast based upon the pace of work PG&E averaged for this activity from 2019-2021.²¹³⁴ The Commission should reject this recommendation for three reasons.

First, Cal Advocates is incorrect in its assumption that PG&E will not have the capacity to complete the work. Cal Advocates misses the point that the lower pace of work from 2019-2021 was due to various resource constraints. In 2019, proactive conductor replacement in MAT 08J was lower due to resource constraints and focus on higher priority work in other

²¹³² PG&E-04, p. 13-28, lines 12-15.

²¹³³ CALPA-06, p. 52, lines 10-16.

²¹³⁴ CALPA-06, p. 52, lines 18-19.

programs such as major emergency, wildfire system hardening within Tier 2 and 3 HFTDs, pole replacements, and overhead maintenance.²¹³⁵ In 2020, proactive conductor replacement in MAT 08J was lower because PG&E needed to direct construction resources to higher priority work which included some emergency overhead conductor replacement, wildfire mitigation work, Public Safety Power Shutoff events, and high-risk, time-dependent maintenance work.²¹³⁶ Later, in 2020 and 2021, the COVID-19 pandemic further required PG&E to defer some work, including deteriorated conductor replacement, to protect the health and safety of workers and the public.²¹³⁷ The deferrals could reasonably be made at that time but are not recommended to continue. It would be imprudent to base future GRC funding for OAM activities on the prior resource-constrained pace of work that occurred from 2019-2021. Increased funding is necessary to address reliability issues as these assets age.

Second, Cal Advocates' proposed forecast reduction, which would provide less than half of PG&E's forecast, is insufficient for a program that is necessary to keep the electric distribution system reliable. While the Overhead Conductor Replacement Program is not specifically tied to wildfire safety, the program is fundamental to maintaining the reliability of the grid for customers.²¹³⁸ PG&E's overhead assets are aging (deteriorating) at a pace faster than the assets can be replaced, particularly in non-HFTD areas.²¹³⁹ To address this challenge, PG&E submitted a forecast sufficient to fund the replacement of an average of 71.3 miles of overhead conductor annually from 2021-2026.²¹⁴⁰ This proposed replacement level will allow PG&E to address the conductors with the highest risk of failure based upon a stringent review

²¹³⁵ A.18-12-009, PG&E's 2019 RSAR (Sept. 23, 2020), p. 3-69, lines 23-30.

²¹³⁶ PG&E-04, p. 13-54, line 10 to p. 13-55, line 5.

²¹³⁷ PG&E-17, p. 13-12, lines 21-24.

²¹³⁸ PG&E-17, p. 13-12, line 29 to p. 13, line 3.

²¹³⁹ PG&E-17, p. 13-13, lines 3-4.

²¹⁴⁰ PG&E-17, p. 13-13, lines 4-7.

process and to maintain a steady replacement of aging conductors in the system.²¹⁴¹ The replacement level is further supported by a 2018 study completed by the National Electric Energy Testing Research and Applications Center (NEETRAC) that concluded a significant annual increase of total conductor replacements would be needed to avoid increasing outage levels.²¹⁴²

Third, PG&E has met forecast replacement levels in the past and is positioned to do so during the GRC forecast period. In 2016, for example, PG&E completed the forecast replacement level of approximately 70 miles.²¹⁴³ Work plans have also been reprioritized to ensure resources are available to complete this work, with new risk assessment tools being developed to prioritize work.²¹⁴⁴ The 2016 replacement rate and PG&E's efforts to reprioritize its resources demonstrate that PG&E's planned replacement rate of 71.3 annual miles is achievable. In short, PG&E must replace more conductor, not less as recommended by Cal Advocates. PG&E's forecast is based upon reasonable and achievable replacement levels, and should be approved.

AARP argues for forecast reductions on the ground that the program forecast is not cost-effective given the low fire risk in non-HFTDs.²¹⁴⁵

The Commission should also reject AARP's recommendation as it is insufficient to maintain system reliability. AARP asserts that the 2018 NEETRAC study does not recommend the increased conductor replacement rate forecast by PG&E and instead only recommends that

²¹⁴¹ PG&E-17, p. 13-13, lines 7-10.

²¹⁴² PG&E-17, PG&E's response to Data Request CalAdvocates_027-Q02, Attachment CalAdvocates_027-Q02Atch01, dated 8/31/21, pp. App A-158, line 140 to App A-159, line 143.

²¹⁴³ PG&E-17, p. 13-13, lines 23-24.

²¹⁴⁴ PG&E-17, p. 13-13, lines 25-27.

²¹⁴⁵ AARP-01, p. 51, line 12 to p. 52, line 12.

more data be collected to guide proactive replacements.²¹⁴⁶ AARP misreads the report, which, as noted above, states that a year-over-year increase in replacement rates is needed to maintain reliability:

[T]o keep the present level of performance (a constant annual sustained outages), the total replacement length (reliability plus emergency & maintenance) needs to have a significant year-over-year increase along with a change in remediation strategy from repair to replace.²¹⁴⁷

PG&E is following this guidance, including placing increased focus on overhead conductor replacements and on targeted analyses to identify those lines with the highest risk of failures. Regardless, in focusing its testimony on wildfire risk as opposed to reliability risk,²¹⁴⁸ AARP appears to miss the point and is generally dismissive of the important role the Overhead Conductor Replacement Program has in ensuring system reliability. The program is fundamental to maintaining system reliability as these assets age. AARP's proposed reduction, which provides less than half of PG&E's forecast, will not provide sufficient funding for this important reliability program.

AARP notes that PG&E routinely replaces conductor for a variety of reasons outside of the Overhead Conductor Replacement Program (such as accommodating new load, distributed energy resources (DER), etc.), and argues that these other activities may make PG&E's Overhead Conductor Replacement Program duplicative and unnecessary.²¹⁴⁹ This is incorrect.

AARP's argument reflects a misunderstanding of the relatively narrow scope of these other conductor-installation activities. This other work is typically dictated by requirements unrelated to reliability, for example, areas with new load increases requiring upgraded

²¹⁴⁶ AARP-01, p. 50, lines 6-9.

²¹⁴⁷ PG&E-17, PG&E's response to Data Request CalAdvocates_027-Q02, Attachment CalAdvocates_027-Q02Atch01, dated 8/31/21, pp. App A-158, line 140 to App A-159, line 143.

²¹⁴⁸ AARP-01, p. 51, lines 13-16.

²¹⁴⁹ AARP-01, p. 51, lines 3-9.

conductor.²¹⁵⁰ In contrast, PG&E’s Overhead Conductor Replacement program focuses on replacing overhead conductor with the highest conductor and splice failure rates.²¹⁵¹ Further reduction of overhead conductor replacement could present safety hazards as well as reliability issues for PG&E customers.

4.13.4.2 PG&E’s Capital Forecast For Grasshopper/Overhead Switch Replacements (MAT 08S) Is Reasonable

Grasshopper switches are obsolete overhead distribution line switches that PG&E is eliminating from its system. PG&E’s Grasshopper/Overhead Switch Replacement Program proactively replaces obsolete switches installed between 1950 and 1970, to minimize potential safety issues during switching operations and to improve reliability.²¹⁵² PG&E’s capital forecast and Cal Advocates’ recommended forecast reductions for Grasshopper/Overhead Switch Replacements (MAT 08S) are summarized below.

**TABLE 4-33:
GRASSHOPPER/OVERHEAD SWITCH REPLACEMENT (MAT 08S) - PG&E’S CAPITAL
FORECAST AND PARTIES RECOMMENDED REDUCTIONS (\$000s)^(a)**

Party	2020 Rec.	2021	2022	2023	2024	2025	2026
PG&E	\$536	\$925	\$949	\$975	\$1,001	\$1,028	\$1,056
Cal Advocates		\$(559)	\$(655)	\$(673)			
(a) PG&E-17, p. 13-28, Table 13-4, line 2 (PG&E recorded and forecast costs); p. 13-29, Table 13-5, line 2; p. 13-5, Table 13-1, line 2 (Parties’ recommendations).							

Cal Advocates’ recommended forecast reduction is based on: (1) reducing PG&E’s 2021, 2022 and 2023 replacement levels.²¹⁵³ Cal Advocates asserts that PG&E did not explain how PG&E scoped the pace of work for the program. That is not so. As explained in rebuttal testimony, PG&E’s proposed replacement rate of 30 switches per year in its 2023 forecast is

²¹⁵⁰ PG&E-17, p. 13-15, lines 4-6.

²¹⁵¹ PG&E-17, p. 13-15, lines 6-9.

²¹⁵² PG&E-04, p. 13-31, lines 15-22.

²¹⁵³ CALPA-06, p. 53, lines 13-18.

consistent with the agreed-upon replacement rate in the 2017 GRC and with the funding authorized in the 2020 GRC, both proceedings in which Cal Advocates was a party.²¹⁵⁴

Cal Advocates' proposed forecast departs from this GRC replacement rate, reducing PG&E's 2021 replacement level to 12 switches and 2022-2023 replacement level to 9 switches per year. Cal Advocates' proposed forecast is less than one-third of what PG&E forecasted and will not provide sufficient funding for this program. As discussed above, Cal Advocates misses the point that the lower pace of work from 2019-2021 was due to various resource constraints. PG&E completed fewer grasshopper switch replacements in MAT 08S during 2020-2021 due to the reprioritization of resources to higher-priority work. The deferrals could reasonably be made at that time but keeping obsolete equipment on PG&E's system should be avoided.

In addition, Cal Advocates' recommended replacement levels are arbitrary. For example, Cal Advocates does not dispute the safety and reliability risks identified by PG&E. Nor does Cal Advocates suggest that PG&E does not have the capacity to complete the work at the level in PG&E's forecast. Without a valid basis to do so, the proposed reduction is not warranted.

PG&E's GRC forecast of approximately \$1 million per year to replace 30 switches per year from 2023 to 2026 is reasonable and should be adopted.

4.13.5 PG&E's Capital Forecast For Distribution Circuit Zone Reliability (MWC 49) Is Reasonable

Work in Distribution Circuit Zone Reliability (MWC 49) focuses on achieving reliability improvements through the following targeted reliability measures: (1) performance of base reliability work including work to improve service to customers; (2) installation of overhead protective devices including fuses; (3) installation of distribution system line reclosers; (4) installation of FuseSaver devices; and (5) installation of Fault Location, Isolation and Service

²¹⁵⁴ PG&E-17, p 13-16, line 30 to p. 13-17, line 1; *see also* A.15-09-001, Joint Motion for Adoption of Settlement Agreement (Aug. 13, 2016), Appendix C, GRC Settlement Agreement (as ratified by D.17-05-013), p. 15, Section 3.1.3.4; A.18-12-009, Settlement Agreement adopted in the final GRC decision, D.20-12-005, pp. 12-13, Section 2.3.6.5.

Restoration (FLISR) systems.²¹⁵⁵ PG&E’s capital forecasts and Cal Advocates’ recommended adjustments for MWC 49 are summarized below.

**TABLE 4-34:
DISTRIBUTION CIRCUIT ZONE RELIABILITY (MWC 49) - PG&E’S CAPITAL FORECAST
AND PARTIES RECOMMENDED REDUCTIONS (\$000s)^(a)**

Party	2020 Rec.	2021	2022	2023	2024	2025	2026
PG&E	\$20,175	\$21,455	\$26,722	\$29,110	\$28,974	\$29,578	\$32,245
Cal Advocates		\$(188)	\$(1,113)	\$(1,143)			
(a) PG&E-17, p. 13-5, Table 13-1, lines 8-14; p. 13-28, Table 13-4, lines 8-14; p. 13-29, Table 13-45 lines 8-14.							

Cal Advocates recommends forecast reductions for one program within PG&E’s capital forecast for MWC 49: Overhead Fuses (MAT49C). PG&E responds to Cal Advocates’ specific contentions below.

4.13.5.1 PG&E’s Capital Forecast For Overhead Fuses (MAT 49C) Is Reasonable

The work in MAT 49C consists of installing new line fuses on overhead distribution circuits in order to limit the impact and scope of outages and limit the number of customers affected.²¹⁵⁶ PG&E plans to install approximately 100 new sets of overhead fuses per year on tap lines to prevent mainline outages.²¹⁵⁷ PG&E’s capital forecast and Cal Advocates’ recommended forecast reductions for MAT 49C are summarized below.

**TABLE 4-35:
OVERHEAD FUSES (MAT 49C) - PG&E’S CAPITAL FORECAST AND PARTIES
RECOMMENDED REDUCTIONS (\$000s)^(a)**

Party	2020 Rec.	2021	2022	2023	2024	2025	2026
PG&E	\$312	\$882	\$1,519	\$1,560	\$1,422	\$1,497	\$2,967
Cal Advocates		\$(188)	\$(1,113)	\$(1,143)			
(a) PG&E-17, p. 13-28, Table 13-4, line 14 (PG&E recorded and forecast costs); p. 13-29, Table 13-5, line 11; p. 13-5, Table 13-1, line 11 (Cal Advocates’ recommendations).							

²¹⁵⁵ PG&E-04, p. 13-44, lines 2-10.

²¹⁵⁶ PG&E-04, p. 13-47, line 28 to p. 13-48, line 2.

²¹⁵⁷ PG&E-17, p. 13-26, lines 6-8.

Cal Advocates recommends reducing PG&E's 2022-2023 pace of work from 129 to 13 installations per year, the approximate average pace of work from 2019-2021.²¹⁵⁸ Cal Advocates proposed reduction is unwarranted.

As PG&E explained in rebuttal testimony, replacement of overhead fuses is a cost-effective targeted reliability program. Cal Advocates does not provide any justification for reducing PG&E's forecast. Indeed, Cal Advocates does not dispute that the work is necessary. Nor does it dispute that PG&E's unit cost forecast is reasonable. Further, Cal Advocates' extrapolation of PG&E's pace of work at 13 units based upon partial 2021 costs is inconsistent with PG&E's actual pace of work for the year. PG&E successfully installed 97 fuses in 2021 as reported in PG&E's Risk Spend Accountability Report.²¹⁵⁹ PG&E plans to increase this pace going forward during the GRC period.²¹⁶⁰ PG&E acknowledges that the lower 2018-2020 pace of work was primarily driven by our focus on wildfire mitigation efforts.²¹⁶¹ However, PG&E has since renewed its efforts to utilize MAT 49C work to improve reliability. The 2023 GRC forecast for MAT 49C reflects PG&E's return to a pace of work similar to its 2016-2017 unit completion rate – which is achievable as demonstrated by PG&E's 2021 actual pace of work.²¹⁶² Accordingly, the Commission should approve PG&E's forecast for MAT 49C.

4.13.6 PG&E's Capital Forecast For Electric Distribution Underground Asset Replacement (MWC 56) Is Reasonable

PG&E's electric underground distribution system consists of primary distribution cable and associated switches, vaults, enclosures, conduits, splices, cable connectors, and other equipment. Capital work in the UAM program primarily consists of replacing underground

²¹⁵⁸ CALPA-06, p. 55, lines 2-5.

²¹⁵⁹ A.18-12-009, PG&E's 2021 RSAR (Mar. 31, 2022), p. 3-20, Table 3-4, line 116.

²¹⁶⁰ PG&E-17, p. 13-27, lines 1-2.

²¹⁶¹ PG&E-17, p. 13-27, lines 2-4.

²¹⁶² PG&E-17, p. 13-27, lines 5-8.

cables and switches.²¹⁶³ PG&E’s capital forecast and Cal Advocates’ total recommended forecast reductions for MWC 56 are summarized below.

**TABLE 4-36:
ELECTRIC DISTRIBUTION UNDERGROUND ASSET REPLACEMENT - PG&E’S CAPITAL
FORECAST AND PARTIES RECOMMENDED REDUCTIONS (\$000s)^(a)**

Party	2020 Rec.	2021	2022	2023	2024	2025	2026
PG&E	\$57,995	\$90,160	\$85,382	\$91,317	\$93,066	\$94,845	\$96,660
Cal Advocates		\$(24,864)	\$(30,653)	\$(26,423)			
(a) PG&E-17, p. 13-5, Table 13-1, lines 3-7; p. 13-28, Table 13-4, lines 3-7; p. 13-29, Table 13-45, lines 3-7.							

Cal Advocates recommends forecast reductions for four programs within MWC 56: (1) Reliability Related Cable Replacement (MAT 56A); (2) Critical Operating Equipment Cable Replacement (MAT 56C); (3) Load Break Oil Rotary Switch Replacements (MAT 56S); and (4) Temperature Alarm Devices (MAT 56T).

PG&E addresses Cal Advocates’ specific contentions below.

4.13.6.1 PG&E’s Capital Forecast For Reliability Related Cable Replacement (MAT 56A) Is Reasonable

MAT 56A includes PG&E’s forecast for proactively replacing underground distribution cable based on reliability performance, age, and type (e.g., PILC, HMWPE, and XLPE cables), or a combination of these factors and other influences. Replacement candidates are primarily identified in areas (protective zones) experiencing two or more cable failures within five years.

PG&E’s capital forecast and Cal Advocates’ recommended forecast reductions for MAT 56A are summarized below.

**TABLE 4-37:
OVERHEAD FUSES (MAT 56A) - PG&E’S CAPITAL FORECAST AND PARTIES
RECOMMENDED REDUCTIONS (\$000s)^(a)**

Party	2020 Rec.	2021	2022	2023	2024	2025	2026
PG&E	\$17,987	\$38,013	\$39,556	\$36,976	\$37,616	\$38,266	\$38,927
Cal Advocates		\$(13,715)	\$(14,671)	\$(8,663)			
(a) PG&E-17, p. 13-28, Table 13-4, line 5 (PG&E recorded and forecast costs); p. 13-29, Table 13-5, line 4; p. 13-29, Table 13-5, line 4 (Cal Advocates’ recommendations).							

²¹⁶³ PG&E-04, p. 13-34, line 1 to p. 13-41, line 7.

Cal Advocates recommends utilizing PG&E's 2018-2020 pace of work to derive a lower forecast, as opposed to PG&E's planned replacement rate.²¹⁶⁴ Cal Advocates argues that the higher pace of work forecast by PG&E is not necessary, and that if the work was high priority, PG&E should not have deferred work from prior years.²¹⁶⁵ Cal Advocates is wrong – the work is necessary and should be funded.

As a threshold matter, Cal Advocates misunderstands what work deferrals mean. It should not be construed as meaning the work is not necessary once the reason for the deferral no longer exists. PG&E deferred certain work that could be reasonably deferred at that time in favor of other higher-priority work within MWC 56.²¹⁶⁶ However, further deferral of the replacement of failing and aging assets is not prudent and would have reliability and safety consequences.

In addition, the Commission should again reject Cal Advocates' pace-of-work argument because it is counter to current circumstances and PG&E's work plans for maintaining a reliable system. PG&E's forecast is needed to maintain a steady proactive replacement of aging cables in the system and to complete certain work originally scheduled in 2019 and 2020 that was rescheduled due to construction and estimating (design) resource constraints.²¹⁶⁷ As discussed above, PG&E's 2018-2020 pace of work was impacted by resource constraints caused by an unanticipated volume of wildfire mitigation and other emergent work.²¹⁶⁸ PG&E's experience since this time has allowed for better forecasting (including resource planning) to accommodate

²¹⁶⁴ CALPA-06, p. 56, lines 15-21.

²¹⁶⁵ CALPA-06, p. 56, lines 9-12.

²¹⁶⁶ PG&E-17, p. 13-19, line 31 to p. 13-20, line 1.

²¹⁶⁷ PG&E-17, p. 13-19, lines 17-21.

²¹⁶⁸ PG&E-17, p. 13-19, lines 21-24.

the new scope of work.²¹⁶⁹ PG&E therefore anticipates that it will not have these same resource constraints during the forecast GRC period.

4.13.6.2 PG&E’s Capital Forecast For COE Cable Replacement (MAT 56C) Is Reasonable

MAT 56C includes PG&E’s forecast for replacing failed sections of underground distribution cable.²¹⁷⁰ MAT 56C is a program that replaces single segments of failed cable as opposed to the MAT 56A program that typically replaces much larger segments of cable over several city blocks. PG&E’s capital forecast and Cal Advocates’ recommended forecast reductions for MAT 56C are summarized below.

**TABLE 4-38:
COE CABLE REPLACEMENT (MAT 56C) - PG&E’S CAPITAL FORECAST AND PARTIES
RECOMMENDED REDUCTIONS (\$000s)^(a)**

Party	2020 Rec.	2021	2022	2023	2024	2025	2026
PG&E	\$21,041	\$34,260	\$33,030	\$36,002	\$36,625	\$37,258	\$37,901
Cal Advocates		\$(3,997)	\$(9,094)	\$(11,418)			
(a) PG&E-17, p. 13-28, Table 13-4, line 7 (PG&E recorded and forecast costs); p. 13-29, Table 13-5, line 5; p. 13-29, Table 13-5, line 5 (Cal Advocates’ recommendations).							

Cal Advocates recommends a downward adjustment based on reducing PG&E’s 2023 GRC forecast pace of work to PG&E’s average pace of work from 2019-2021, which was about 134 projects per year.²¹⁷¹ The Commission should reject this pace-of-work recommendation for the same reasons as its other pace-of-work recommendations discussed above.

The lower pace of work executed in 2019-2020 was caused by construction and estimating (design) resource constraints.²¹⁷² Cal Advocates’ concern that PG&E will not be able to increase the pace of work due to continued resource constraints similar to those

²¹⁶⁹ PG&E-17, p. 13-19, lines 24-25.

²¹⁷⁰ When failures of underground cables occur and the nature of the failure requires immediate replacement or repair, that work is charged to MWC 17 – Routine Emergency Capital or BH – Routine Emergency Expense.

²¹⁷¹ CALPA-06, p. 58, lines 9-15.

²¹⁷² PG&E-17, p. 13-20, lines 22-25.

experienced in 2019-2020 misses the point of PG&E’s forecast, however. Those particular past constraints have been addressed. As PG&E has become more experienced at resourcing both wildfire mitigation work and base work, PG&E has adjusted its resource plans accordingly, which is reflected in PG&E’s forecast.²¹⁷³ For example, PG&E has proposed to bolster its estimating resources, which will facilitate PG&E’s capacity to complete the work.²¹⁷⁴ Notably, Cal Advocates does not dispute the need for the work to be completed. The Commission should adopt PG&E’s 2023 GRC forecast for cable replacement under MAT 56C.

4.13.6.3 PG&E’s Capital Forecast For LBOR Switch Replacement (MAT 56S) Is Reasonable

The MAT 56S program targets the removal of antiquated LBOR switches, which are manually operated, oil-filled underground switches that use solid blade mechanisms immersed in oil to break or make loads.²¹⁷⁵ LBOR switches pose a safety risk for crews, as they may fail when operating.²¹⁷⁶ PG&E is working to replace these antiquated switches with devices that conform to current design standards.²¹⁷⁷ PG&E’s capital forecast and Cal Advocates’ recommended forecast reductions for MAT 56S are summarized below.

**TABLE 4-39:
LBOR SWITCH REPLACEMENT (MAT 56S) - PG&E’S CAPITAL FORECAST AND PARTIES
RECOMMENDED REDUCTIONS (\$000s)^(a)**

Party	2020 Rec.	2021	2022	2023	2024	2025	2026
PG&E	\$5,415	\$9,252	\$9,493	\$8,124	\$8,344	\$8,569	\$8,800
Cal Advocates		\$(6,491)	\$(6,680)	\$(5,715)			
(a) PG&E-17, p. 13-28, Table 13-4, line 9 (PG&E recorded and forecast costs); p. 13-29, Table 13-5, line 6; p. 13-5, Table 13-1, line 6 (Cal Advocates’ recommendations).							

²¹⁷³ PG&E-17, p. 13-20, line 28 to p. 13-21, line 4.

²¹⁷⁴ PG&E-17, p. 13-21, lines 4-6.

²¹⁷⁵ PG&E-04, p. 13-39, lines 27-29.

²¹⁷⁶ PG&E-17, p. 13-21, lines 21-22.

²¹⁷⁷ PG&E-17, p. 13-21, lines 23-24.

Cal Advocates recommends a two-thirds decrease from PG&E's forecast, based on using a five-year average unit cost.²¹⁷⁸ Cal Advocates argues that PG&E only should target LBOR switches without oil inspection sight glasses, and that a two-thirds forecast reduction is justified because only about one-third of PG&E's pre-1975 LBOR switches lack oil-inspection glasses and need to be replaced (with the remaining two-thirds not requiring replacement).²¹⁷⁹ Cal Advocates misunderstands the reasons why PG&E is replacing the switches – one hundred percent of the switches must be replaced for public- and employee-safety reasons. For this reason, PG&E's MAT 56S program targets the removal of *all* antiquated pre-1975 LBOR switches.²¹⁸⁰

Cal Advocates confuses the purpose and significance of the sight glass. The presence of a sight glass only allows workers to determine whether there is oil in the switch; but it does not provide information about the dielectric-insulating quality of that oil.²¹⁸¹ PG&E must replace all switches, because as they age through normal operation, increasing carbonization in the oil makes it more likely for the oil to break down and the switch to fail.²¹⁸² The sight glass allows a measure of safety for crews operating a switch, but it is not determinative in the prioritization of replacement of pre-1975 LBOR switches.²¹⁸³ That is, pre-1975 LBOR switches with sight glasses are not prioritized over replacement pre-1975 LBOR switches without sight glasses – all pre-1975 LBOR switches must be replaced.²¹⁸⁴ Statements from the CPUC's Safety and

²¹⁷⁸ CALPA-06, p. 60, lines 4-17.

²¹⁷⁹ CALPA-06, p. 60, lines 8-13.

²¹⁸⁰ PG&E-17, PG&E's response to Data Request TURN_024-Q04(c), dated 10/5/21, pp. App A-184 to App A-185.

²¹⁸¹ PG&E-17, p. 13-22, lines 10-12.

²¹⁸² PG&E-17, p. 13-22, lines 12-15.

²¹⁸³ PG&E-17, p. 13-22, lines 15-18.

²¹⁸⁴ PG&E-17, p. 13-22, lines 6-10.

Enforcement Division (previously known as the Office of the Safety Advocates (OSA)) support this plan, recommending that the Commission require PG&E to significantly accelerate the replacement of pre-1975 switches:

The Commission should require PG&E to accelerate the replacement of pre-1975 vintage oil-filled switches still in operation. These switches are a known safety hazard and pose a threat to public safety and PG&E employees. The continued operation of these switches, long past their service life, elevates the risk of a catastrophic event occurring and threatens the safety of the public and PG&E employees. OSA recommends that the Commission direct PG&E to focus its efforts in this GRC cycle to replace pre-1975 vintage oil-filled switches at a replacement rate of 676 switches annually from 2020 to 2022.²¹⁸⁵

The Commission should reject Cal Advocates proposed two-thirds reduction and approve PG&E's forecast for MAT 56S so that PG&E can replace all pre-1975 LBOR switches.

4.13.6.4 PG&E's Capital Forecast For Temperature Alarm Devices (MAT 56T) Is Reasonable

Initiated in 2018, the Temperature Alarm Devices (TAD) program (MAT 56T) involves installation of temperature monitors on targeted oil-filled subsurface equipment.²¹⁸⁶ A TAD is a battery powered remote sensing unit that continuously captures and analyzes temperature data from the oil-filled equipment.²¹⁸⁷ The program will allow PG&E to transition to a data-informed asset replacement strategy to prevent catastrophic equipment failures.²¹⁸⁸

PG&E's capital forecast and Cal Advocates' recommended forecast reductions for MAT 56T are summarized below.

²¹⁸⁵ A.18-12-009, HE-275: Exhibit (OSA-01), p. 2-1, line 25 to p. 2-2, line 7.

²¹⁸⁶ PG&E-04, p. 13-41, lines 9-11.

²¹⁸⁷ PG&E-04, p. 13-41, lines 12-15.

²¹⁸⁸ PG&E-04, p. 13-41, lines 25-27.

**TABLE 4-40:
TEMPERATURE ALARM DEVICES (MAT 56T) - PG&E'S CAPITAL FORECAST AND
PARTIES RECOMMENDED REDUCTIONS (\$000s)^(a)**

Party	2020 Rec.	2021	2022	2023	2024	2025	2026
PG&E	\$8,162	\$9,589	\$3,303	\$9,099	\$9,345	\$9,597	\$9,856
Cal Advocates		\$(661)	\$(228)	\$(626)			
(a) PG&E-17, p. 13-28, Table 13-4, line 10 (PG&E recorded and forecast costs); p. 13-29, Table 13-5, line 7; p. 13-5, Table 13-1, line 7 (Cal Advocates' recommendations).							

Cal Advocates recommends using the 2019-2020 average costs as opposed to a 2018-2020 average that includes 2018 start-up costs for the program.²¹⁸⁹ Cal Advocates reasons that PG&E should no longer experience startup costs moving forward.²¹⁹⁰ Cal Advocates' reasoning is incorrect.

Because the program is still relatively new, PG&E is still incurring start-up-related costs similar to those incurred in 2018.²¹⁹¹ For example, PG&E is developing a long-term connectivity strategy (and incurring associated startup costs), which includes implementing a new cyber-safe approach outside of PG&E's Distribution Control Center (DCC).²¹⁹² For this reason, Cal Advocates' recommendation to remove 2018 costs from the averaging methodology will cause the program to be underfunded. This underfunding also will be exacerbated, as PG&E expects material costs to increase compared to previous years.²¹⁹³ Accordingly, the unit cost for 2021 to 2026 should be based on a normalized 3-year average from 2018 to 2020, escalated for 2021 through 2026 as PG&E proposes. The Commission should approve PG&E's forecast for MAT 56T in full.

²¹⁸⁹ CALPA-06, p. 62, lines 2-9.

²¹⁹⁰ CALPA-06, p. 62, lines 4-6.

²¹⁹¹ PG&E-17, p. 13-25, lines 5-6.

²¹⁹² PG&E-17, p. 13-25, lines 6-10.

²¹⁹³ PG&E-17, p. 13-25, lines 11-13.

4.14 Network Asset Management

PG&E's distribution networks serve a broad spectrum of commercial and residential customers in the high-density areas of downtown San Francisco and downtown Oakland.²¹⁹⁴ The network system, which is located underneath sidewalks and streets or in high-rise buildings where people live and work, is designed to have the full capacity to serve customers without any power interruption or any negative consequences to network assets in the event of one asset failure.²¹⁹⁵ To achieve this, redundancy is built into the network system to meet the higher reliability needs in limited space commonly found in urban areas.²¹⁹⁶ PG&E's customers who rely on the network system for power include multi-dwelling residences and hotels, San Francisco Bay Area transit stations, large office towers, government buildings, and large commercial buildings.²¹⁹⁷ Thus, even a brief outage can result in significant negative impacts to thousands of residential and commercial customers, significant loss of customer business revenues, and potential disruption to medical services and various governmental functions such as public transportation. Given the magnitude of the impacts when there is an outage, there is generally an expectation that service be restored as soon as practicable.

In the sections that follow, PG&E: (1) summarizes the expense and capital forecast for network asset management programs; (2) summarizes AARP's recommendations concerning this program; and (3) demonstrates that PG&E's capital forecasts for installing and replacing network assets (MWC 2C) and underground assets (MWC 56) are reasonable.

²¹⁹⁴ PG&E-04, p. 14-1, lines 10-11.

²¹⁹⁵ PG&E-04, p. 14-1, lines 10-17; PG&E-17, p. 14-8, lines 13-17.

²¹⁹⁶ PG&E-04, p. 14-1, lines 19-20.

²¹⁹⁷ PG&E-17, p. 14-8, lines 27-30.

4.14.1 PG&E's Expense and Capital Forecast

PG&E's TY 2023 expense forecast presented in rebuttal testimony is \$5.021 million.²¹⁹⁸ PG&E's TY 2023 forecast presented in the JCE, including the September escalation adjustment, is \$5.300 million,²¹⁹⁹ PG&E's expense forecast is tracked in MWC KC, Network Preventive Maintenance and Repair, and is uncontested. See Appendix A.

PG&E capital expenditures forecast presented in rebuttal testimony is \$41.067 million in 2021, \$43.938 million in 2022, \$44.423 million in 2023, \$45.312 million in 2024, \$46.265 million in 2025, and \$47.269 million in 2026.²²⁰⁰ PG&E's capital expenditures forecast presented in the JCE, including the September escalation adjustment, is \$42.338 million in 2021, \$47,896 million in 2022, and \$50.177 million in 2023, \$52.995 million in 2024, \$54.217 million in 2025, and \$54.160 million in 2026.²²⁰¹ Capital work is tracked in two MWCs: Install/Replace Network Assets (MWC 2C); and Electric Distribution Underground Asset Replacement (MWC 56).

4.14.2 PG&E's Capital Forecast For Install/Replace Network Assets (MWC 2C) and Underground Asset Replacement (MWC 56) Are Reasonable

Work recorded in MWC 2C includes ongoing replacement of network transformers and network protectors, installation of new SCADA safety monitoring equipment, and the installation of new venting manhole covers on vaults.²²⁰² Work recorded in MWC 56 includes reliability-related replacement of primary and secondary network cables. PG&E's capital forecasts and AARP's total recommended forecast reductions for MWC 2C and MWC 56 are summarized below.

²¹⁹⁸ PG&E-17, p. 14-3, Table 14-1, line 2.

²¹⁹⁹ PG&E-64, p. 3-2, Table 3A-1, line 76.

²²⁰⁰ PG&E-17, p. 14-19, Table 14-6, line 8.

²²⁰¹ PG&E-67, WP-3, lines "[Exhibit 4, Chapter] 14," MWCs 56 and 2C.

²²⁰² PG&E-17, p. 14-10, lines 24-27.

**TABLE 4-41:
INSTALL/REPLACE NETWORK ASSETS / UNDERGROUND ASSET REPLACEMENT -
PG&E’S CAPITAL FORECAST AND PARTIES
RECOMMENDED REDUCTIONS (\$000s)^(a)**

Party	2020 Rec.	2021	2022	2023	2024	2025	2026
PG&E	\$44,495	\$41,067	\$43,938	\$44,423	\$45,312	\$46,265	\$47,269
AARP				\$(18,750)	\$(17,482)	\$(17,922)	\$(18,732)
(a) PG&E-17, p. 14-5, Table 14-3, line 5; p. 14-19, Table 1, 4-6, line 8.							

AARP recommends disallowing a combined \$72.5 million (more than one-third) of PG&E’s capital forecast for network/underground asset replacement programs from 2023 to 2026. These programs include the following four Failure of Distribution Network Assets risk mitigations discussed in PG&E’s opening testimony: (1) Installation of Supervisory Control and Data Acquisition (SCADA) Equipment for Safety Monitoring, (2) Incremental Primary Network Cable Replacements, (3) Network Component Replacements – High-Rise Dry-Type Transformers, and (4) Network Component Replacements – Targeted Network Protector Replacement.²²⁰³ AARP contends “that there is absolutely no justification for pre-emptive replacement of network assets of any kind” because “virtually all sections of the downtown network are served by multiple power sources” due to the redundant grid design.²²⁰⁴ Noting that there has not been a customer outage for customers served by PG&E’s San Francisco and Oakland network systems since 2009, AARP concludes that spending on SCADA installations and network component replacements (cable, protectors, and transforms) offers “no reliability improvement value” and is unnecessary.²²⁰⁵

Before addressing AARP’s specific contentions regarding the four mitigations listed above, PG&E discusses several overarching issues.

²²⁰³ AARP-01, p. 46, lines 10-11 and p. 53, Table, line “Network Capital (PG&E-04, 14-12).”

²²⁰⁴ AARP-01, p. 44, line 13 to p. 45, line 2.

²²⁰⁵ AARP-01, p. 45, lines 1-15.

4.14.2.1 AARP Misunderstands PG&E's Network System, Network Asset Management Program, And Customer Benefits

First, AARP misdescribes and misunderstands PG&E's network asset management programs. AARP characterizes PG&E's replacement programs as though PG&E replaces assets based solely on "subjective" criteria such as age alone, without assessing the operational condition of the asset and whether it needs to be replaced.²²⁰⁶ This is incorrect. When identifying assets requiring replacement, PG&E's network asset management program includes, among other things, monitoring the condition of network assets through several measures, such as inspections, service records, testing, analysis, and on-line sensor monitoring.²²⁰⁷ PG&E further considers relevant factors such as expected service life, repairability, and obsolescence.²²⁰⁸ In short, PG&E's program is a condition-based program, which means that PG&E replaces assets based upon PG&E's engineers' and operators' assessment of the suitability of the asset to remain in service or be replaced.

Second, AARP ignores the purpose and design of the system; the network system is designed to provide safe and reliable service to customers without any power interruption or any negative consequences to network assets in the event of a *single* asset failure. In a networked system, customers can receive power from one of several sources, so that an outage on one of those sources will not result in a system wide outage for the customer.²²⁰⁹ In other words, the targeted, condition-based replacements PG&E forecasts in this GRC are necessary to maintain network integrity in order to minimize the chance that multiple (two or more) simultaneous failures could lead to an outage that impacted customers. Remarkably, AARP appears to be

²²⁰⁶ AARP-01, p. 48, lines 5-10 (AARP defining what it refers to as pre-emptive replacement) and p. 49, lines 15-16 (AARP asserting that PG&E extensively utilizes pre-emptive replacement strategies).

²²⁰⁷ PG&E-04, p. 14-14, lines 13-15; p. 14-15, lines 11-14 and 22-26.

²²⁰⁸ PG&E-04, p. 14-15, lines 3-4 (noting units at the end of the useful lives); lines 13-14 (noting the difficulty of items to repair due to obsolescence).

²²⁰⁹ PG&E-04, p. 14-5, lines 20-23.

dismissive regarding system reliability issues, as though PG&E's replacement activities should cease until an asset failure threatens or causes an outage. Such a cavalier approach to customers' interests in reliable, outage-free service in their homes and businesses is unacceptable.

Third, AARP's discussion regarding PG&E's network asset management program is incomplete, focusing primarily on reliability and ignoring public and employee safety issues. Network systems are located in high-density areas of downtown San Francisco and Oakland, where thousands of customers live and work. The failure of electric distribution network assets or lack of remote operation functionality may result in public or employee safety issues, property damage, and/or environmental damage.²²¹⁰ Therefore, in addition to enhancing reliability, the network replacements planned by PG&E are essential to maintaining public and employee safety.

Fourth, AARP fails to understand or acknowledge the potentially catastrophic consequences that could occur if failures occur. As PG&E explained in its rebuttal testimony, if multiple failures occur, customers will experience outages.²²¹¹ In turn, multiple failures occurring on the same network circuits, or the same network group, would further exacerbate outages.²²¹² Further, in the event of such failures, the remaining energized assets serving customers will experience significant increased load.²²¹³ If these conditions remained for an extended period of time (e.g., longer than 24 hours), network cables and equipment would be at risk of catastrophic failures.²²¹⁴ Additionally, while redundancy provides reliability to network customers, it also results in higher fault duties (i.e., unintended, uncontrolled, high current flow

²²¹⁰ PG&E-04, p. 14-8, lines 3-7.

²²¹¹ PG&E-17, p. 14-8, lines 1-9.

²²¹² PG&E-17, p. 14-9, lines 1-3.

²²¹³ PG&E-17, p. 14-9, lines 3-5.

²²¹⁴ PG&E-17, p. 14-9, lines 5-7.

through an electrical system).²²¹⁵ In the event of an asset failure, these high fault duties can result in catastrophic failures such as manhole explosions/fire and poses safety risks to employees and the public.²²¹⁶ PG&E's asset management plan is designed to prevent these potentially catastrophic events from occurring.

4.14.2.2 PG&E's Network Asset Management Activities Are Critical To Maintaining The Current Reliability Of The Network System

PG&E's network system has performed well overall over the past five years under PG&E's focused programmatic asset management approach,²²¹⁷ which targeted proactive replacement assets at risk of failure in order to maintain system reliability and safety. AARP correctly notes that of the "60 network equipment failures PG&E reports from 2016 through 2020, not a single customer outage resulted."²²¹⁸ These failures also did not result in any safety incidents. While this data reveals that PG&E has maintained reliability through its proactive network asset management activities, what this data does not show is the number of aging (deteriorating and obsolete) assets in PG&E's network systems requiring replacement. PG&E's concern about potential failures of these aging assets is warranted. For example, many existing network primary and secondary cables date from the 1920s to the 1960s and are reaching the end of their service life;²²¹⁹ PG&E has identified 22 older dry type transformers in high-rise buildings, mostly installed in the 1980s, that are at the end of their useful lives;²²²⁰ and there are network protectors still in service dating back to the 1940s through the 1970s with manufacturer

²²¹⁵ PG&E-17, p. 14-9, lines 7-9.

²²¹⁶ PG&E-17, p. 14-9, lines 9-12.

²²¹⁷ PG&E-04, p. 14-2, lines 1-2.

²²¹⁸ AARP-01, p. 45, lines 4-5.

²²¹⁹ PG&E-04, p. 14-20, lines 15-17.

²²²⁰ PG&E-04, WP 14-33.

rated service lives of approximately 35 years.²²²¹ These assets should be replaced, not run to failure as AARP would appear to recommend.

It is also important to note that network asset repair activities generally take much longer compared to replacement activities on a radial underground system.²²²² Due to the location of network assets (underground and in high-rise buildings in a congested downtown environment), repairs usually require coordination with customers, clearances, permitting (with local agencies and transit agencies), and specialized resources to perform repairs.²²²³ Indeed, repairs to several network assets could take weeks or months to complete, while leaving customers vulnerable to additional asset failures, which could possibly result in prolonged outage times.²²²⁴ Due to the length of these repairs, it is prudent for PG&E to coordinate its asset replacement work on a planned basis and schedule, as opposed to addressing repair or replacement issues on an emergent basis.

PG&E addresses AARP's specific contentions regard four separate replacement activities in the sections below.

4.14.2.3 PG&E's Capital Forecast For Network Transformer and Protector Replacement (MAT 2CC) Is Reasonable

MAT 2CC includes four replacement programs for network protectors and transformers: (1) oil filled transformers in high rise buildings, (2) vintage dry type transformers in high rise buildings, (3) CMD type network protectors, and (4) condition-based network component

²²²¹ PG&E-04, WP 14-33.

²²²² PG&E-17, p. 14-10, lines 5-6.

²²²³ PG&E-17, p. 14-10, lines 6-9.

²²²⁴ PG&E-17, p. 14-10, lines 9-12.

(transformer, protector) replacements.²²²⁵ The Network Transformer and Protector Replacement program is more fully discussed in PG&E’s prepared testimony.²²²⁶

AARP proposes disallowing the 2023-2026 forecast for two mitigation activities in this program: (1) Network Component Replacements – High-Rise Dry-Type Transformers and (2) Network Component Replacements – Targeted Network Protector Replacement.²²²⁷ AARP argues that replacing dry-type transformers is unnecessary from a safety perspective, citing that “despite tens of thousands of transformers located in high-rise buildings across the U.S., we do not know of any incidents where one caused a fire, let alone any such incidents involving a dry-type transformer.”²²²⁸ AARP further argues that PG&E’s low RSE for the program demonstrates the low safety risk.²²²⁹

4.14.2.3.1 PG&E’s Forecast For Network Component Replacements – High-Rise Dry-Type Transformers Should Be Adopted In Full

In focusing primarily on safety-issues, AARP misses the point of these particular transformer replacement activities. As PG&E explained in rebuttal testimony, the principal driver for this work is reliability, not safety. The dry-type transformers planned for replacement are older dry-type transformers located in high-rise buildings.²²³⁰ The units are at the end of their useful lives and some of them have rust and other corrosion.²²³¹ The replacement transformers are either explosion resistant or dry type and use a single tank design to minimize

²²²⁵ PG&E-17, p. 14-11, lines 7-12.

²²²⁶ PG&E-04, Ch. 14, p. 14-8, lines 1-14, Section 2.a.1.

²²²⁷ AARP-01, p. 46, lines 10-11; p. 53, Table, line “Network Capital (PG&E-04, 14-12).”

²²²⁸ AARP-01, p. 46, lines 2-8.

²²²⁹ AARP-01, p. 46, lines 8-9.

²²³⁰ PG&E-17, p. 14-12, lines 9-11.

²²³¹ PG&E-17, p. 14-12, lines 11-12.

the risk of catastrophic failure.²²³² The RSE for the program is low because the program primarily addresses reliability, not safety.²²³³

Further, many, if not all, of these older dry-type transformers are custom-made and PG&E does not stock any spare units.²²³⁴ Historically, a replacement unit takes six to eight months to acquire under normal supply chain conditions.²²³⁵ Without funding for this program, PG&E would not be able to plan proactive replacements of older dry-type transformers, putting customers at risk of prolonged outages in the event of network asset failures.

4.14.2.3.2 PG&E's Forecast For Network Component Replacements – Targeted Network Protector Replacement Should Be Adopted In Full

AARP recommends no funding for Network Component Replacements – Targeted Network Protector Replacement.²²³⁶ AARP contends there is absolutely no justification for pre-emptive replacement of network assets of any kind, and that if a network protector fails, it can be replaced with no interruption in service to customers.²²³⁷

As discussed above, identifying and replacing deteriorated, damaged, or obsolete equipment proactively is fundamental to maintaining system reliability. PG&E's network system has four types of network protectors. Of the four types, PG&E has concluded that CMD network protectors are more ergonomically difficult to repair and replace as they have obsolete components.²²³⁸ This program will replace all CMD units in the PG&E network with more

²²³² PG&E-04, p. 14-14, line 30 to p. 14-15, line 7.

²²³³ PG&E-17, p. 14-12, lines 14-16.

²²³⁴ PG&E-17, p. 14-12, lines 22-23.

²²³⁵ PG&E-17, p. 14-12, lines 23-24.

²²³⁶ AARP-01, p. 45, lines 1-2; p. 53, Table, line "Network Capital (PG&E-04, 14-12)."

²²³⁷ AARP-01, p. 45, lines 1-4.

²²³⁸ PG&E-17, p. 14-13, lines 14-17.

reliable network protector models.²²³⁹ Proactive replacement of network protectors help maintain system reliability.

4.14.2.4 PG&E's Capital Forecast For Network SCADA Safety Monitoring (MAT 2CE) Is Reasonable

Network SCADA Safety Monitoring (MAT 2CE) is a continuation of a program to upgrade the 1980s vintage SCADA monitoring equipment on PG&E's twelve Electric Distribution Network groups.²²⁴⁰ The upgraded system provides additional equipment-condition information not provided by the older existing SCADA system, which allows PG&E to identify equipment conditions that can be addressed before in-service failure occurs.²²⁴¹ It also allows the operators to remotely open and close the network protectors, decreasing the need to send crews into network vaults to manually operate the equipment.²²⁴² PG&E's opening testimony provides further details regarding this program.²²⁴³ These new features enhance the safety, reliability, and efficiency of the network systems.

AARP proposes that the Commission authorize zero funding for this activity. AARP contends that SCADA equipment upgrades are not necessary for three reasons. First, AARP suggests that SCADA monitoring upgrades are not necessary because identifying network equipment that might fail in advance of an in-service failure offers no reliability improvement value.²²⁴⁴ Second, AARP argues that SCADA upgrades will not result in enough labor savings

²²³⁹ PG&E-04, p. 14-15, lines 11-16.

²²⁴⁰ PG&E-04, p. 14-17, lines 27-29.

²²⁴¹ PG&E-04, p. 14-17, line 29 to p. 14-18, line 1.

²²⁴² PG&E-04, p. 14-18, lines 1-4.

²²⁴³ PG&E-04, p. 14-17, line 26 to p. 14-18, line 13, Section 2.a.4.

²²⁴⁴ AARP-01, p. 45, lines 13-15.

to justify the cost of the upgrades.²²⁴⁵ Third, AARP claims that SCADA upgrades will not improve safety since no network safety incidents were reported from 2016-2020.²²⁴⁶ PG&E disagrees with these contentions. AARP's objection to SCADA monitoring upgrades is perplexing, given AARP's position that utilities should use objective criteria to determine which assets require replacement.²²⁴⁷ The upgraded SCADA system will facilitate identifying failing assets with objective criteria.

SCADA monitoring provides reliability improvement value. The existing network SCADA systems were installed in the 1980s and are past their projected life expectancy. Although useful, these older systems are based on obsolete technology and significantly limited, only measuring load and open/close status of the network protectors.²²⁴⁸ The new upgraded SCADA systems are designed to improve safety on the distribution networks. They also will monitor additional conditions including oil temperature, oil level, and tank pressure to identify issues in a specific transformer.²²⁴⁹ In addition, the new systems have control capabilities allowing Distribution Operators to remove a unit from service remotely if a system identifies a problem on the transformer or protector.²²⁵⁰ Information from the systems is used for real time safety assessment and is part of the condition-based maintenance and replacement process now used for the distribution network systems.²²⁵¹

²²⁴⁵ AARP-01, p. 45, lines 15-17. AARP misinterprets the SCADA monitoring benefit of “decreasing the need to send crews into network vaults to manually operate the equipment” as a labor savings benefit that PG&E is touting. PG&E's discussion of this benefit was intended to emphasize the safety benefits. In regard to labor savings, this could be an additional benefit that SCADA monitoring provides. But it is not PG&E's justification of the costs for this program.

²²⁴⁶ AARP-01, p. 45, lines 9-18.

²²⁴⁷ AARP-01, p. 47, line 5 to p. 48 line 2.

²²⁴⁸ PG&E-17, p. 14-15, lines 2-4.

²²⁴⁹ PG&E-17, p. 14-15, lines 6-8.

²²⁵⁰ PG&E-17, p. 14-15, lines 8-11.

²²⁵¹ PG&E-04, WP 14-24.

In regard to AARP’s comments regarding labor savings, AARP misses the point. The purpose of SCADA monitoring upgrades is not labor savings; SCADA is the key system to monitor equipment health to reduce risks of in-service failures in order to ensure safe and reliable operations.²²⁵² The primary purpose of upgrading SCADA monitoring equipment is to allow PG&E to identify equipment conditions that can be addressed before in-service failure occurs.²²⁵³ Again, AARP’s objection is surprising, given that the upgraded SCADA monitoring system will provide objective information to inform PG&E’s asset management decisions.

Finally, AARP’s assertion that SCADA upgrades will not improve safety is wrong. AARP notes that “[r]egarding safety improvements, PG&E reported zero network safety incidents from 2016-2020.”²²⁵⁴ AARP’s logic assumes that safety improvements are impossible when there are no recorded safety incidents, which, of course, is nonsensical. The existing SCADA systems have provided the ability for remote monitoring and load information, which contributed to the zero safety incidents. The proposed SCADA monitoring upgrades would replace this obsolete technology and provide additional functionality. Further, SCADA upgrades enable remote operation, which reduces the instances of PG&E employees will have to work in dangerous conditions when opening or closing network protectors.²²⁵⁵ AARP’s reasoning is also counter to prudent utility practices to reasonably incorporate safety improvements even in the absence of documented safety incidents.

In sum, AARP’s SCADA-defunding recommendation is unreasonable. Disallowing the forecasts would leave the existing 1980s-era SCADA systems, which do not provide the information necessary for condition-based maintenance and replacement, in place. This system

²²⁵² PG&E-04, WP 14-25.

²²⁵³ PG&E-17, p. 14-15, lines 18-20.

²²⁵⁴ AARP-01, p. 45, lines 17-18.

²²⁵⁵ PG&E-17, p. 14-16, lines 1-3.

is critical to reduce in-service failures for safe and reliable operations. The Commission should approve PG&E's requested funding for the program.

4.14.2.5 PG&E's Capital Forecast For Primary Network Cable Replacement Program (MAT 56N) Is Reasonable

The Primary Network Cable Replacement program involves the systematic replacement of network cable assets.²²⁵⁶ The design of PG&E's network systems inherently results in facilities capable of releasing a significant amount of energy if a failure occurs, posing a safety risk to customers, public, and PG&E workers.²²⁵⁷ The Primary Network Cable Replacement program is more fully discussed in PG&E's prepared testimony.²²⁵⁸

AARP recommends that the Commission authorize zero funding for this program. Similar to its other contentions, AARP continues to claim there is absolutely no justification for pre-emptive replacement of any network assets.²²⁵⁹ AARP is again wrong.

Primary and secondary network cable failures pose a safety risk. Failures can result in electrical outages, equipment damage, explosions, smoke and fires; some of which may cause personal injury and property damage.²²⁶⁰ These risks are more consequential with network cables since network cables are located in dense urban environments with significant pedestrian traffic.

Since 2008, there have been a total of 145 network cable and splice failures in San Francisco and Oakland.²²⁶¹ As these facilities age, PG&E anticipates continued cable and

²²⁵⁶ PG&E-04, p. 14-20, lines 4-5.

²²⁵⁷ PG&E-04, p. 14-20, lines 5-7.

²²⁵⁸ PG&E-04, p. 14-20, line 2 to p. 14-21, line 7.

²²⁵⁹ AARP-01, p. 45, lines 1-3.

²²⁶⁰ PG&E-17, p. 14-17, lines 11-14.

²²⁶¹ PG&E-17, p. 14-17, lines 17-18.

splice failures.²²⁶² Some of these failures were catastrophic failures which, while rare, resulted in fires, manhole displacements, and/or vault explosions with significant public safety consequences.²²⁶³ Many of the existing network primary and secondary cables date from the 1920s to the 1960s and are reaching the end of their service life.²²⁶⁴ This program will expedite the completion of primary cable replacements on the network system.²²⁶⁵ Without funding this for this program, aging primary network cables are at risk of failing and pose a safety risk to people and property in close proximity to the network system.

4.15 Substation Asset Management

PG&E's Substation Asset Management programs manage assets in PG&E's electric distribution substations, which transform high voltage electricity from PG&E's electric transmission system to lower voltage for delivery to PG&E's customers. PG&E's TY 2023 expense forecast for Substation Asset Management is in MWC GC. The expense forecast presented in rebuttal testimony is \$50.940 million²²⁶⁶ and is uncontested. MWC GC includes three types of expense activities: (1) Preventive Maintenance; (2) Corrective Maintenance; and (3) Substation Support Activities. PG&E's JCE forecast, including the September escalation adjustment, is \$56.977 million.²²⁶⁷

PG&E's capital expenditures forecast presented in rebuttal testimony is \$225.282 million in 2021, \$204.167 million in 2022, \$208.129 million in 2023, \$214.944 million in 2024, \$222.071 million in 2025, and \$227.837 million in 2026.²²⁶⁸ PG&E's JCE forecast, including

²²⁶² PG&E-04, WP 14-28.

²²⁶³ PG&E-04, p. 14-5, lines 33 to p. 14-6, line 2.

²²⁶⁴ PG&E-04, p. 14-20, lines 15-17.

²²⁶⁵ PG&E-04, p. 14-20, lines 15-31.

²²⁶⁶ PG&E-17, p. 15-31, Table 15-5, line 5.

²²⁶⁷ PG&E-64, p. 3-2, Table 3A-1, line 77.

²²⁶⁸ PG&E-17, p. 15-32, Table 15-6, line 16.

the September escalation adjustment, is \$232.257 million in 2021, \$222.560 million in 2022, \$235.085 million in 2023, \$251.200 million in 2024, \$260.238 million in 2025, and \$261.050 million in 2026.²²⁶⁹ PG&E's capital forecast consists of four MWCs (MWC 48, MWC 54, MWC 58 and MWC 59). The forecast for MWC 59, Substation Emergency Replacement, was uncontested (see Appendix A). Portions of the capital forecasts for the other MWCs are contested. PG&E addresses the contested MWCs below.

4.15.1 Electric Distribution Substation, Replace Other Equipment (MWC 48)

PG&E records costs for various substation equipment replacements in MWC 48. This work includes all substation equipment replacements other than transformers.²²⁷⁰ PG&E's capital forecast and TURN's, Cal Advocates', and AARP's recommended reductions for MWC 48 are summarized below.

**TABLE 4-42:
MWC 48: PG&E'S FORECAST AND PARTIES
RECOMMENDED REDUCTIONS (\$000s)^(a)**

Party	2020 Rec.	2021	2022	2023	2024	2025	2026
PG&E	\$77,377	\$76,601	\$96,588	\$96,331	\$87,218	\$84,078	\$77,723
Cal Advocates	\$(1,500)	\$(13,844)	\$(21,054)	\$(27,574)			
TURN			\$(21,568)	\$(18,616)			
AARP				\$(30,536)	\$(39,909)	\$(44,659)	\$(38,721)
(a) PGE-17, p. 15-33, Table 15-7, lines 1-9 (2021 and 2022); p. 15-4, Table 14-2, lines 1-9 (2023); p. 15-5, Table 15-3, lines 1-9 (2023-2026).							

MWC 48 consists of eleven MATs, three of which are uncontested (MATs 48A, 48B and 48R, Other Equipment Replacement Work). The uncontested MATs represent \$4.220 million of PG&E's 2023 forecast.²²⁷¹ Cal Advocates recommends reductions to MATs 48D, 48X, 48C,

²²⁶⁹ PG&E-67, WP-3, lines "[Exhibit 4, Chapter] 15," MWCs 48, 54, 58, 59, 65 and 09.

²²⁷⁰ PG&E-04, p. 15-23, lines 2-4.

²²⁷¹ PG&E-17, p. 15-4, Table 15-2, line 9.

48H, 48N, 48E, and 48F.²²⁷² TURN recommends reductions to MAT 48D only. AARP recommends reductions to MATs 48D, 48E, and 48L. Each of the contested MATs is addressed below.

4.15.1.1 Circuit Breaker Replacement – Capital (MAT 48D)

Through its Circuit Breaker replacement program in MAT 48D, PG&E prioritizes and replaces deteriorating and obsolete distribution circuit breakers before in-service failure.²²⁷³ PG&E's 2023 forecast for MAT 48D as presented in rebuttal is \$28.6 million.²²⁷⁴ Cal Advocates, TURN, and AARP recommend reductions to PG&E's forecast.

Cal Advocates recommends an annual spending level equal to PG&E's escalated maximum spending from 2016-2020. Cal Advocates' recommended reduction for 2023 is \$12.7 million.²²⁷⁵ Cal Advocates argues that PG&E's forecasts for a number of substation asset management programs, including MAT 48D, should be set at historical levels of spending, because PG&E has not demonstrated it can complete more work than previously performed. Cal Advocates asserts that PG&E is continuing to forecast elevated levels of high priority work and doubts whether PG&E will have the capacity to increase its routine work beyond recent historical levels.²²⁷⁶ Cal Advocates also argues that PG&E has not provided sufficient justification for its routine replacement programs to show that its forecast pace of work is

²²⁷² Cal Advocates also proposes shifting some of PG&E's 2021 forecast for Line Support Work (MAT 48L) to 2022. CALPA-06, p. 72, line 13 to p. 73, line 2. PG&E does not believe that it is appropriate to shift forecast funds that were not used in a particular MAT in 2021 to 2022 both because 2022 is a separate forecast year and because PG&E routinely does less work than forecast in some MATs while doing more work than forecast in others.

²²⁷³ PG&E-04, p. 15-24, line 19 to p. 15-25, line 5.

²²⁷⁴ PG&E-17, p. 15-4, Table 15-2, line 2.

²²⁷⁵ PG&E-17, p. 15-4, Table 15-2, line 2.

²²⁷⁶ CALPA-06, p. 21, lines 9-19.

necessary in spite of continued growth of higher risk work.²²⁷⁷ Cal Advocates' concerns are not well founded.

PG&E's increased focus on certain proactive substation equipment replacement programs like the circuit breaker replacement in MAT 48D is balanced by forecast reductions below 2020 recorded spending in other substation program areas such as Switchgear Replacement (MAT 48F), Transformer Replacement (MAT 54A), and wildfire related work in Substation Emergency (MWC 59).²²⁷⁸ The forecast reduction in MAT 48F spending is due to recent completion of many switchgear projects²²⁷⁹ and the forecast reduction in MAT 54A spending specifically reflects PG&E's decision to free up additional resources for circuit breaker replacement in MAT 48D.²²⁸⁰

PG&E did spend less than forecast in MAT 48D in 2021, mainly because PG&E's spending was constrained by the need to perform higher priority switchgear work related to the unexpected Larkin project delays discussed in PG&E's RSAR.²²⁸¹ However, PG&E does not expect those constraints to continue into the 2023 GRC cycle.²²⁸² PG&E's spending on proactive transformer replacement in MAT 54A has also been much higher than the low imputed amount authorized in the 2020 GRC because the Just-In-Time (JIT) replacement strategy upon which the 2020 GRC forecast was based did not completely meet PG&E's needs.²²⁸³ Similarly, emergency substation equipment replacements in MWC 59 have been higher than the imputed

²²⁷⁷ CALPA-06, p. 22, lines 3-5.

²²⁷⁸ PG&E-17, p. 15-9, lines 4-9.

²²⁷⁹ PG&E-04, p. 15-24, lines 7-15.

²²⁸⁰ PG&E-04, p. 15-31, line 30 to p. 15-32, line 4.

²²⁸¹ A.18-12-009, PG&E's RSAR (Mar. 31, 2022), p. 3-19, Table 3-4, line 106.

²²⁸² PG&E-17, p. 15-9, lines 19-22.

²²⁸³ PG&E-17, PG&E's response to Data Request TURN_094-Q01, dated 2/25/22, pp. App A-220 to App A-221.

amounts authorized in the 2020 GRC because PG&E instituted a new wildfire risk-related inspection process that led to the identification of more emergency equipment replacement than forecast.²²⁸⁴ Going forward, PG&E has adjusted its MAT 54A forecast to reflect more appropriate levels of work, and expects emergency replacement work related to wildfire activities to taper off into the 2023 GRC cycle.²²⁸⁵

Cal Advocates' proposal to set PG&E's funding based on a historical average also ignores the fact that the population of substation assets near end-of-life continues to grow. It is critical to start ramping back up to a sustainable level of proactive replacements to continue to serve our customers safely and reliably.

Finally, Cal Advocates' proposal ignores the advantages of proactive replacement of substation assets versus JIT/emergency replacement. Proactive work allows time to schedule work efficiently, whereas JIT work is less predictable and can disrupt other planned work. The ability to schedule clearances in advance reduces delays and customer impact. Advance planning can also reduce safety risks of catastrophic failures and overtime costs.²²⁸⁶ More importantly, planned projects deliver reliability and cost-efficiencies over the lifecycle of substation equipment. JIT/emergency replacement generally just replaces a single component that has failed or is about to fail; planned replacements bundle related work at the same substation together, eliminating the need for multiple projects as associated components fail. This bundled approach to equipment replacement is especially appropriate in older substations, where most equipment components are nearing the end of useful life and design configurations

²²⁸⁴ A.18-12-009, PG&E's RSAR (Mar. 31, 2022), p. 3-22, Table 3-4, line 153.

²²⁸⁵ PG&E-17, p. 15-10, lines 7-10.

²²⁸⁶ PG&E-17, p. 15-10, line 24 to p. 15-11, line 1, fn. 17 (citing PG&E-17, PG&E's response to Data Request TURN_094-Q01, dated 2/25/22, pp. App A-220 to App A-221).

are not standard (which increases the cost of piecemeal replacements).²²⁸⁷ Adopting a JIT-only approach when the overall circuit breaker failure rate is high and proactive replacement rates are lower than guardrail rates could potentially lead to an increase in in-service failures with accompanying safety risks, reliability impacts, environmental impacts, and collateral damage to adjacent equipment.²²⁸⁸

TURN proposes reductions to PG&E's 2022 and 2023 capital forecasts. TURN's proposed reduction for 2023 is \$18.6 million.²²⁸⁹ In the alternative, TURN proposes that MAT 48D work be placed in a one-way balancing account.²²⁹⁰ TURN notes that PG&E's forecast is higher than historical amounts and is based on a proposed ramp up of proactive replacement programs. TURN argues that PG&E has not adequately supported the need for increased proactive replacement and that although PG&E cited higher circuit breaker failure rates as a justification for an increased replacement rate and had a high replacement rate in 2020, PG&E's circuit breaker failure counts have decreased over the 2016-2020 period.²²⁹¹ TURN also argues that PG&E has a long history of deferring forecasted proactive circuit breaker replacements.²²⁹² TURN argues that, given these facts, PG&E's MAT 48D forecast should be based on a five-year (2016-2020) historical average, plus escalation.²²⁹³

TURN incorrectly claims that PG&E has not adequately supported its requested ramp-up of proactive circuit breaker replacements. PG&E has prioritized forecasts within this GRC cycle

²²⁸⁷ PG&E-17, p. 15-11, lines 1-13, fns. 18, 19, (citing PG&E-17, PG&E's response to Data Request TURN_094-Q01 and Attachment TURN_094-Q01Atch04, dated 2/25/22, pp. App A-220 to App A-221, and App A-228).

²²⁸⁸ PG&E-17, p. 15-11, lines 16-20.

²²⁸⁹ PG&E-17, p. 15-4, Table 15-2, line 2.

²²⁹⁰ TURN-09, p. 56, lines 16-17.

²²⁹¹ TURN-09, p. 56, line 5 to p. 60, line 5.

²²⁹² TURN-09, p. 59, line 1 to p. 60, line 5.

²²⁹³ TURN-09, p. 56, lines 11-12.

to support proactive circuit breaker replacements.²²⁹⁴ PG&E experienced 32 breaker failures in 2020, which is more than the 2017-2019 three-year average of 24 breaker failures.²²⁹⁵ Even if future failures rates are closer the 2017-2019 average, the optimal approach to reducing this failure rate is through an increased rate of proactive planned replacement. Additionally, PG&E has a significant population of circuit breakers near or at the end-of-life. Though actual useful life is dependent on operation and external factors (i.e., loading, environment, etc.), approximately 38 percent of PG&E's circuit breakers are beyond industry end-of-life (>35 years) or nearing end-of-life (30 to 35 years) out of a total of 3,011 distribution breakers in the system.²²⁹⁶ A JIT-only replacement strategy is ill-equipped to address the potentially large percentage of assets nearing end-of-life because it would place an undue burden on PG&E's operations to establish clearances, potentially lead to shortages in the emergency breaker fleet, and create a high-stress working environment for crews that may lead to compromised construction.²²⁹⁷

TURN's alternative recommendation that MAT 48D funding be placed in a balancing account is equally unavailing. PG&E should have the flexibility to appropriately prioritize its substation work to meet circumstances as they arise. For example, given the unexpected growth in wildfire-related emergency equipment replacement work in this GRC cycle, it has been appropriate for PG&E to spend more in that area and less in MAT 48D. A balancing account would deprive PG&E of that flexibility to respond to emergent priorities not known at the time of the GRC filling.²²⁹⁸

²²⁹⁴ PG&E-04, p. 15-24, line 26 to p. 15-25, line 5.

²²⁹⁵ PG&E-17, PG&E's response to Data Request CalAdvocates_228-Q03, dated 2/1/22, pp. App A-218 to App A-219.

²²⁹⁶ PG&E-17, PG&E's response to Data Request CalAdvocates_228-Q03, dated 2/1/22, pp. App A-218 to App A-219.

²²⁹⁷ PG&E-17, p. 15-12, line 24 to p. 15-13, line 6.

²²⁹⁸ PG&E-17, p. 15-13, lines 9-15.

Finally, AARP recommends large reductions to several of PG&E’s proactive replacement programs for substation equipment, including circuit breaker replacement in MAT 48D.²²⁹⁹ AARP’s recommended reduction for MAT 48D in 2023 is \$28.4 million.²³⁰⁰ For circuit breaker and other proactive replacement programs, AARP argues that JIT replacement of substation equipment—i.e., replacing equipment after it has failed or when test results suggest that imminent failure is likely to occur²³⁰¹—is a more appropriate strategy than proactive replacement. AARP claims that JIT replacement strategies rely on periodic, objective testing to identify equipment that is likely to fail,²³⁰² whereas proactive strategies “select[] equipment for replacement outside of these objective identification methods, utilizing subjective assessments of the need to replace assets, such as age, or ‘condition’... which are poor predictors of equipment failure compared to objective testing.”²³⁰³ AARP claims that age relative to the fleet average or depreciation period is not an appropriate basis for determining when equipment should be replaced because many pieces of equipment last longer than the depreciation period and early replacement of that equipment will deprive customers of decades of useful life of equipment they have paid for.²³⁰⁴

AARP incorrectly claims that PG&E’s criteria for proactive substation equipment replacement are not objective and/or lead to replacements of equipment that is likely to have a

2299 AARP also makes similar recommendations for Switch Replacement (MAT 48E), Line Work (48L), and proactive transformer replacement (MWC 54A). These recommendations will be discussed below. Compare AARP-01, p. 50 (table showing recommended reductions for MWC 48 and MWC 54 programs) with PG&E-04, WP 15-35, lines 2, 5, 10 and 15 (showing forecasts for MATs 48D, 48E, 48L, and the transformer replacement portion of MAT 54A).

2300 PG&E-17, p. 15-5, Table 15-3, line 2.

2301 PG&E replaces substation equipment that has failed or that it has determined is likely to fail imminently through its Substation Emergency Equipment Replacement program in MWC 59. *See* PG&E-04, p. 15-40, line 1 to p. 15-41, line 7.

2302 AARP-01, p. 47, line 5 to p. 48, line 2.

2303 AARP-01, p. 48, lines 5-9.

2304 AARP-01, p. 48, line 11 to p. 49, line 2.

significant amount of useful life left at the time of replacement. PG&E does use objective criteria to focus its proactive replacement programs on units that have known issues and are most to likely fail in the near future.²³⁰⁵ As described in greater detail in PG&E's discussion of Cal Advocates' recommendations for MAT 48D above, there are many benefits to taking a proactive approach to substation equipment replacement rather than relying completely on a JIT/emergency replacement strategy. Moreover, PG&E has a large population of assets at or near end-of-life. Without targeting a sustainable level of proactive replacements each year, it will not be feasible to address the cluster of failures that is likely to occur when a large population of assets all reach end-of-life around the same time. AARP fails to point to any other utility that uses a reactive-only strategy to replace their substation assets.²³⁰⁶

4.15.1.2 Cal Advocates' Other Recommended Forecast Reductions (MATs 48X, 48C, 48E, 48H, 48N)

Cal Advocates also recommends forecast reductions to five other substation MATs: Animal Abatement (MAT 48X), Battery Replacement (MAT 48C), Switch Replacement (MAT 48E); Civil Structures (MAT 48H), and Insulator Replacement (MAT 48N). PG&E summarizes the work in these MATs, its 2023 forecast, and Cal Advocates' proposed reductions below.

MAT 48X consists of the implementation of animal abatement measures in substations identified through known animal contacts. PG&E's 2023 forecast for MAT 48X presented in rebuttal is \$5.8 million.²³⁰⁷ Cal Advocates' proposed reduction for 2023 is \$3.5 million.²³⁰⁸

²³⁰⁵ PG&E-17, p. 15-14, lines 19-24.

²³⁰⁶ PG&E-17, p. 15-15, lines 5-11.

²³⁰⁷ PG&E-04, p. 15-25, lines 6-17; PG&E-04, WP 15-40 to WP 15-41; PG&E-17, p. 15-4, Table 15-2, line 3.

²³⁰⁸ PG&E-17, p. 15-4, Table 15-2, line 3.

MAT 48C consists of proactive replacement of substation batteries. PG&E's 2023 forecast for MAT 48C presented in rebuttal is \$3.3 million.²³⁰⁹ Cal Advocates' proposed reduction for 2023 is \$2.9 million.²³¹⁰

MAT 48E consists of the replacement of distribution substation switch types such as disconnect switches, motor-operated air switches, and circuit switchers. PG&E's 2023 forecast for MAT 48E presented in rebuttal is \$2.2 million.²³¹¹ Cal Advocates' proposed reduction for 2023 is \$0.2 million.²³¹²

MAT 48H consists of the proactive replacement of structures in substations such as roofs, as well as current-carrying equipment (e.g., conductor). PG&E's 2023 forecast for MAT 48H presented in rebuttal is \$5.4 million.²³¹³ Cal Advocates' proposed reduction for 2023 is \$4.9 million.²³¹⁴

MAT 48N consists of the proactive replacement of types of insulators that have known failure modes. PG&E's 2023 forecast for MAT 48N presented in rebuttal is \$5.4 million.²³¹⁵ Cal Advocates' proposed reduction for 2023 is \$3.4 million.²³¹⁶

Cal Advocates' proposed reductions to all of these MATs are based on its argument, discussed above in Section 4.15.1.1, that PG&E's forecasts for substation maintenance should be

²³⁰⁹ PG&E-04, p. 15-25, line 18 to p. 15-26, line 4; PG&E-04, WP 15-42 to WP 15-43; PG&E-17, p. 15-4, Table 15-2, line 4.

²³¹⁰ PG&E-17, p. 15-4, Table 15-2, line 4.

²³¹¹ PG&E-04, WP 15-59 to WP 15-60; PG&E-17, p. 15-4, Table 15-2, line 8.

²³¹² PG&E-17, p. 15-4, Table 15-2, line 8.

²³¹³ PG&E-04, p. 15-27, line 22 to 15-28, line 12; PG&E-04, WP 15-46 to WP 15-48; PG&E-17, p. 15-4, Table 15-2, line 6.

²³¹⁴ PG&E-17, p. 15-4, Table 15-2, line 6.

²³¹⁵ PG&E-04, p. 15-28, line 13 to 15-29, line 2; PG&E-04, WP 15-51 to WP 15-52; PG&E-17, p. 15-4, Table 15-2, line 7.

²³¹⁶ PG&E-17, p. 15-4, Table 15-2, line 7.

set at the level of 2019-2021 spending because PG&E has not demonstrated it can complete more work than that.²³¹⁷ For the reasons set forth above, PG&E believes its substation proactive replacement program forecasts are reasonable and that the level of planned work is achievable. Proactive replacement has several advantages over JIT replacement and should be part of a comprehensive replacement strategy along with emergency replacement. PG&E's rebuttal testimony provides additional, program-specific reasons why PG&E's forecasts for these five MATs should not be reduced.²³¹⁸

4.15.1.3 AARP's Other Recommended Reductions (MATs 48E and 48L)

AARP proposes reductions to PG&E's 2023-2026 capital forecasts for MAT 48E (Switch Replacement) and MAT 48L (Line Work Support) based on the same justification as AARP's recommended reduction to MAT 48D (described above in Section 4.15.1.1) – that JIT replacement of substation equipment is a more appropriate strategy than proactive replacement.²³¹⁹ AARP's proposed reduction to MAT 48E is \$2.2 million for 2023, \$4.5 million for 2024, \$4.6 million for 2025, and \$3.5 million for 2026, which is all of PG&E's forecast for that MAT.²³²⁰ AARP's proposed reduction to MAT 48L begins in 2024, with a \$5.6 million reduction to PG&E's 2024 forecast of \$7.9 million.²³²¹

AARP's recommendations for MAT 48E and MAT 48L fail for the same reasons that its arguments failed for MAT 48D. As discussed above in Section 4.15.1.1, AARP's assumptions about PG&E's proactive replacement program are incorrect and proactive replacement has

²³¹⁷ CALPA-06, p. 69, line 16 to p. 70, line 3 (MAT 48X); p. 71, lines 5-13 (MAT 48C); p. 77, lines 2-5 (MAT 48E); p. 74, lines 7-10 (MAT 48H); p. 75, lines 4-17 (MAT 48N).

²³¹⁸ PG&E-17, p. 15-16, lines 11-21 (MAT 48X); p. 15-17, lines 16-30 (MAT 48C); p. 15-22, lines 19-26 (MAT 48E); p. 15-20, lines 18-24 (MAT 48H); p. 15-21, lines 16-24 (MAT 48N).

²³¹⁹ AARP-01, p. 46, line 16 to p. 47, line 2 (MAT 48E); p. 47, line 4 to p. 49, line 12 (MAT 48L).

²³²⁰ PG&E-17, p. 15-5, Table 15-3, line 8.

²³²¹ PG&E-17, p. 15-4, Table 15-2, line 5 (PG&E forecast); p. 15-5, Table 15-3, line 5 (AARP reduction).

significant advantages over emergency replacement. Defunding proactive substation equipment replacement would not only deprive PG&E customers of the advantages of proactive replacement discussed above, it would also lead to additional in-service failures that would need to be replaced on a JIT/emergency basis as part of PG&E's Emergency Substation Equipment Replacement program in MWC 59.²³²² In addition, with respect to MAT 48L, not all the line work forecast in MAT 48L is associated with the proactive replacement projects AARP criticizes; it also includes funding for line work associated with switchgear replacement projects, which AARP has not criticized. AARP's proposed reductions would eliminate funding for line work necessary for PG&E to complete its switchgear replacement projects.²³²³

4.15.1.4 Cal Advocates' Proposed Disallowance to PG&E's 2020 Recorded Costs for Switchgear Replacement (MAT 48F) Should Not Be Adopted

Work in MAT 48F consists of the proactive replacement of deteriorated distribution substation switchgear equipment, which includes electrical disconnect switches, bus conductors, and circuit breakers.²³²⁴ PG&E's 2023 forecast for MAT 48F is \$32.433 million.²³²⁵

Cal Advocates proposes a disallowance of \$1.5 million from PG&E's 2020 recorded costs for MAT 48F, noting that PG&E's El Cerrito G substation rebuild project had \$1.5 million in costs for delays and design extension due to the involvement of multiple engineering teams in the design process that led to design gaps. Cal Advocates argues these costs should be disallowed because they were caused by PG&E's engineering process and might have been avoided with better coordination.²³²⁶

²³²² PG&E-17, p. 15-23, lines 19-26.

²³²³ PG&E-17, p. 15-19, line 13-18.

²³²⁴ PG&E-04, p. 15-23, lines 22-25; PG&E-04, WP 15-61 to WP 15-63.

²³²⁵ PG&E-17, p. 15-4, Table 15-2, line 1.

²³²⁶ CALPA-06, p. 66, lines 7-13.

As PG&E explained in its rebuttal testimony, the El Cerrito G project was more complicated than expected and required four different engineering groups – Line Engineering, Substation Engineering (internal and external), and Distribution Estimating – to complete separate but interrelated portions of the overall project design.²³²⁷ The involvement of multiple engineering teams in the design process is not a flaw in the design process, but rather a natural result of the complexity of the El Cerrito G project and of scope/schedule/cost refinement in the course of project execution.

4.15.2 Electric Distribution Substation, Replace Transformer (MWC 54)

Work in MWC 54 includes transformer replacements, emergency material procurement, and transformer reconditioning.²³²⁸ PG&E’s capital forecast and Cal Advocates’ and AARP’s recommended reductions for MWC 54 are summarized below.

**TABLE 4-43:
MWC 54: PG&E’S FORECAST AND PARTIES
RECOMMENDED REDUCTIONS (\$000s)^(a)**

Party	2020 Rec.	2021	2022	2023	2024	2025	2026
PG&E	\$31,907	\$40,766	\$27,970	\$21,243	\$30,294	\$35,418	\$38,721
Cal Advocates		\$(1,048)	\$(330)	\$(239)			
AARP				\$(16,014)	\$(23,991)	\$(28,472)	\$(31,329)
(a) PGE-17, p. 15-33, Table 15-7, line 10; p. 15-6, Table 15-4, line 10; p. 15-5, Table 15-3, line 10; p. 15-4, Table 15-2, line 10.							

MWC 54 consists of two MATs – MAT 54A and 54L. MAT 54L is uncontested and represents \$3.25 million of PG&E’s 2023 forecast.

MAT 54A includes two distinct activities: (1) substation transformer replacement and (2) emergency equipment procurement (mobile transformers).²³²⁹ Cal Advocates contends that certain risk mitigations should reduce the frequency and/or impact of PG&E emergencies

²³²⁷ PG&E-17, p. 15-24, lines 17-28.

²³²⁸ PG&E-04, p. 15-31, lines 1-6.

²³²⁹ PG&E-04, p. 15-31, line 7 to p. 15-33, line 2; PG&E-04, WP 15-64 to WP 15-66.

compared to the historical norm and therefore reduce the cost to perform emergency work.²³³⁰ Similar to its recommendations for proactive replacement programs in MWC 48, AARP recommends a large reduction to PG&E's proactive transformer replacement program in MAT 54A, on the theory that proactive replacement is not cost effective.²³³¹

The Commission should not adopt Cal Advocates' or AARP's recommendations. PG&E explains why Cal Advocates' analysis is incorrect and its recommendation should not be adopted in Section 4.2.3.4 of this brief. A reduction to the emergency program could limit PG&E's emergency readiness.²³³²

With respect to AARP's recommendation, as PG&E explains above in Sections 4.15.1.1 and 4.15.1.3, targeted proactive replacement of substation equipment is a reasonable, appropriate approach to the long-term management of substation assets. PG&E maintains an inventory of emergency mobile and spare transformers that complements the transformer fleet to provide coverage for transformer failures and planned project contingency support.²³³³ The desired level of inventory is based on planned projects, projected failure trends, and tracking actual usage. AARP's proposed reductions would jeopardize this balance. In addition, PG&E's forecast already includes a reduction in funding for planned transformer replacements to accommodate an increase to the MAT 48D circuit breaker replacement program.²³³⁴

Transformer replacement on a planned basis has several operational advantages. Proactive transformer replacement involves a project scoping phase that includes stakeholder input to determine the capacity needs, system protection and automation requirements, and the

²³³⁰ CALPA-06, p. 11, lines 17-21.

²³³¹ AARP-01, p. 46, line 13 to p. 50, line 3; p. 52, line 13 to p. 53, line 1.

²³³² PG&E-17, p. 15-26, lines 12-17.

²³³³ PG&E-17, PG&E's response to Data Request AARP_006-Q15, dated 5/18/22, pp. App A-186 to App A-188.

²³³⁴ PG&E-17, p. 15-27, lines 1-12.

ultimate substation design. These requirements determine whether additional asset replacements should be added to the project scope to meet long term objectives to maintain safe and reliable service. For example, an increase in transformer size may warrant a new substation battery and building expansion. Emergency transformer replacements, whether they are JIT or in-service failures, bypass this process and do not afford the same efficiencies or opportunities to improve the system to address existing concerns or further needs.²³³⁵

4.15.3 Electric Distribution Substation, Safety and Security (MWC 58)

MWC 58 is made up of programs related to substation security and safety.²³³⁶ PG&E's capital forecast and Cal Advocates' recommended reductions for MWC 58 are summarized below.

**TABLE 4-44:
MWC 58: PG&E'S FORECAST AND PARTIES
RECOMMENDED REDUCTIONS (\$000s)^(a)**

Party	2020 Rec.	2021	2022	2023	2024	2025	2026
PG&E	\$3,369	\$5,980	\$1,738	\$8,233	\$12,883	\$15,743	\$22,218
Cal Advocates		\$(1,648)	\$1,750	(3,060)			
(a) PGE-17, p. 15-33, Table 15-7, lines 11-13; p. 15-4, Table 15-2, lines 11-13.							

MWC 58 consists of four MATs, two of which (MATs 58B and 58C) are uncontested. See Appendix A. Cal Advocates makes recommendations for MAT 58A (Fire Suppression and Safety)²³³⁷ and MWC 58S (Distribution Substation and Security).²³³⁸

²³³⁵ PG&E-17, p. 15-27, lines 16-27.

²³³⁶ PG&E-04, p. 15-36, line 1 to p. 15-39, Table 15-11.

²³³⁷ MAT 58A work consists of installing, replacing, or upgrading fire mitigations as required by local fire marshals and state regulations. PG&E-04, p. 15-36, lines 15-31; PG&E-04, WP 15-57 to 15-58.

²³³⁸ MAT 58S work consists of the installation, upgrade or replacement of physical security measures within substations. PG&E-04, p. 15-37, line 12 to p. 15-38, line 2; PG&E-04, WP 15-57 to WP 15-58.

For MAT 58A, Cal Advocates recommends shifting approximately \$1.6 million from PG&E's 2021 forecast to PG&E's 2022 forecast to account for low spending in 2021.²³³⁹ For MAT 58S, Cal Advocates recommends, as it did with programs in MWC 48, that PG&E be held to the level of its historical spending because it has not shown it is capable at completing more work than that. Cal Advocates also claims that the Commission did not dictate the pace of work for the completion of the security projects it directed be completed.²³⁴⁰

With respect to MAT 58A, PG&E does not believe it is appropriate to shift forecast funds that were not used in a particular MAT in 2021 to 2022 both because 2022 is a separate forecast year and because PG&E routinely does less work than forecast in some MATs while doing more work than forecast in others.

Cal Advocates' recommendation for MAT 58S is inappropriate for the general reasons discussed above in Section 4.15.1.1 with respect to MWC 48D; PG&E believes that its forecasts are reasonable and that the level of work they contemplate is achievable. Cal Advocates' other argument—that security project funding can be reduced because the Commission did not set a deadline for completing that mandated security work—is misplaced. PG&E has reasonably forecast fence replacements and security mitigations based on an approved plan in coordination with the Commission. Although the Commission did not explicitly dictate the pace of work, it approved PG&E's final physical security plan, which includes the mitigation plan to the Commission, with the expectation that it will be implemented in a timely fashion, which requires PG&E to spend more in this MAT code than it has in the recent past.²³⁴¹

²³³⁹ CALPA-06, p. 80, lines 1-2.

²³⁴⁰ CALPA-06, p. 81, lines 13-17.

²³⁴¹ PG&E-17, p. 15-30, lines 4-14.

4.16 Distribution System Automation And Protection (DSAP)

4.16.1 PG&E's Expense And Capital Forecast Is Uncontested

PG&E's TY 2023 expense forecast presented in rebuttal testimony is \$3.008 million²³⁴² and is uncontested. See Appendix A. PG&E's TY 2023 forecast in the JCE, including the September escalation adjustment, is \$3.234 million.²³⁴³ Expense work is tracked in MWC HX – DSAP Support.

PG&E's capital expenditures forecast presented in rebuttal testimony is \$25.483 million in 2021, \$26.371 million in 2022, \$27.003 million in 2023, \$27.745 million in 2024, \$28.540 million in 2025, and \$29.281 million in 2026.²³⁴⁴ PG&E's capital expenditures forecast in the JCE, including the September escalation adjustment, is \$26.262 million in 2021, \$30.439 million in 2022, \$32.443 million in 2023, \$33.463 million in 2024, \$34.064 million in 2025, and \$34.459 million in 2026.²³⁴⁵ PG&E's capital work is tracked in MWC 09, Electric Distribution SAP. PG&E's capital forecast is also uncontested. See Appendix A.

4.17 Electric Distribution Capacity, Engineering and Planning

4.17.1 PG&E's Expense And Capital Forecast

PG&E's TY 2023 expense forecast presented in rebuttal testimony is \$19.943 million²³⁴⁶ and is uncontested. See Appendix A. PG&E's TY 2023 forecast in the JCE, including the September escalation adjustment, is \$20.473 million.²³⁴⁷ Expense work is tracked in MWC FZ – Electric Engineering and Planning.

²³⁴² PG&E-17, p. 2-4, Table 2-1, line 17.

²³⁴³ PG&E-64, p. 3-2, Table 3A-1, line 78.

²³⁴⁴ PG&E-17, p. 2-5, Table 2-2, line 14 (2021); p. 2-6, Table 2-3, line 14 (2022); p. 2-7, Table 2-4, line 14 (2023).

²³⁴⁵ PG&E-67, WP-3, line "[Exhibit 4, Chapter] 16," MWC 09.

²³⁴⁶ PG&E-17, p. 17-3, Table 17-1, line 6.

²³⁴⁷ PG&E-64, p. 3-2, Table 3A-1, line 79.

PG&E capital expenditures forecast as presented in rebuttal testimony is \$286.313 million in 2021, \$215.512 million in 2022, \$195.738 million in 2023, \$231.234 million in 2024, \$248.299 million in 2025, and \$262.219 million in 2026.²³⁴⁸ PG&E’s capital expenditures forecast, including the September escalation adjustment, is \$322.278 million in 2021, \$234.927 million in 2022, \$221.089 million in 2023, \$270.239 million in 2024, \$290.974 million in 2025, and \$300.444 million in 2026.²³⁴⁹ PG&E’s capital work is tracked in MWC 06, Distribution Line Capacity, and MWC 46, Distribution Substation Capacity.

4.17.1.1 Electric Distribution Capacity -- Capital (MWCs 06 and 46)

Work in MWC 06 consists of capacity expansion work outside of substations. Work in MWC 46 consists of upgrades to various pieces of distribution substation equipment that are forecast to have a capacity deficiency. PG&E’s combined capital forecast for MWCs 06 and 46 and Cal Advocates’ and TURN’s recommended reductions are summarized below.²³⁵⁰

**TABLE 4-45:
ELECTRIC DISTRIBUTION CAPACITY - PG&E’S CAPITAL FORECAST AND PARTIES
RECOMMENDED REDUCTIONS (\$000s)^(a)**

Party	2020 Rec.	2021	2022	2023	2024	2025	2026
PG&E	\$143,525	\$286,313	\$215,512	\$195,738	\$231,234	\$248,299	\$262,219
Cal Advocates		\$(69,868)	\$(40,174)	\$(18,410)			
TURN				\$(30,000)			
(a) PG&E-17, p. 17-4, Table 17-3, line 7; p. 17-18, Table 17-5, line 17; p. 17-19, Table 17-6, line 8; p. 17-4, Table 17-2, lines 3, 5 and 7.							

PG&E addresses the disputed areas of its MWC 06 and MWC 46 forecasts below.

²³⁴⁸ PG&E-17, p. 17-18, Table 17-5, line 17.

²³⁴⁹ PG&E-67, WP-3, lines "[Exhibit 4, Chapter] 17," MWCs 06, 10 and 46 (2021, 2023-2026); PG&E-64, p. 3-11, Table 3B-2, lines 63-64 (2022).

²³⁵⁰ Cal Advocates and JCCA also raised an issue with respect to the Renz Energy Storage project but that issue has been resolved. PG&E-17, p. 17-16, lines 19-22.

4.17.1.1.1 Cal Advocates' Proposed Reduction to PG&E's 2022 Forecast for MAT 06H Should Not Be Adopted

Cal Advocates proposes a reduction to PG&E's 2022 forecast for MAT 06H (New Business-Related Capacity Work) due to PG&E's lower than expected historical spending in 2021. Cal Advocates notes that in 2021 PG&E spent significantly less than its forecast for MAT 06H and that PG&E's explanation for that variance was that it was based on "Estimating, Dependency and Construction resources diverted to higher priority work (Wildfire Mitigation Plan and High Fire Threat District Tag Initiative)."²³⁵¹ Cal Advocates argues that similar resource shortages are likely to affect 2022 work and recommends that PG&E's 2022 forecast be reduced by the same proportion that PG&E's 2021 recorded spending in MAT 06H was less than its 2021 forecast.²³⁵²

The Commission should not adopt Cal Advocates' recommendation. The existence of lower spending in 2021 does not automatically indicate lower spending will occur in 2022. In fact, it indicates the opposite is likely, as incomplete work is carried over from 2021 into 2022, increasing the need for 2022 funding rather than reducing it. Cal Advocates' recommended funding level is insufficient to complete to work forecast for 2022. If anything, PG&E's forecast should be higher than it actually is. Since the 2023 GRC forecast was finalized, PG&E has received numerous new applications for service that will require capacity work to serve. As PG&E explained in rebuttal, estimates of total load from new applications for service have grown significantly in recent years, in large part due to increased demand for EV charging.²³⁵³

4.17.1.1.2 Cal Advocates' Proposed Reductions To MATs 46H And 06H Forecasts For Garberville Project Should Not Be Adopted

Cal Advocates also recommends that PG&E's entire capital expenditure forecast for its Garberville capacity project be removed from the GRC. Cal Advocates notes that PG&E stated

²³⁵¹ CALPA-06, p. 88, lines 9-10.

²³⁵² CALPA-06, p. 89, lines 14-21.

²³⁵³ PG&E-17, p. 17-6, line 27 to p. 17-7, line 8.

in discovery that the scope of the Garberville Project is under review by a consultant, that the project now includes transmission needs, and that the ultimate solution will include a mixture of traditional wires solutions and DERs.²³⁵⁴ Cal Advocates thinks the scope and timeline of the project are very uncertain and recommends that, given this level of uncertainty, the project's capital expenditure forecasts be removed from the GRC.²³⁵⁵

The Commission should not adopt Cal Advocates' recommendation. Since the 2023 GRC was filed, several other MAT 06H projects have become necessary due to new loads in the Garberville area. These projects will be designed and constructed prior to the Garberville Substation project and include a line work project to reconductor 8,000 feet of overhead line on the Newburg and Rio Dell circuits and a project that will install 19,000 feet of new overhead line to support additional substation capacity at Rio Dell Substation. If there are changes to the Garberville project timeline that result in lower spend than forecast in the GRC test year, the unused funding would be deployed to the project in the GRC attrition years or to the other Garberville area capacity projects described above or other emergent capacity projects during the 2023 GRC period. These potential emergent projects include multiple applications for service for electric vehicle fast charging stations received after the 2023 GRC. The emergent capacity forecast in the GRC is insufficient to cover these projects. The six largest EV projects would enable 195 MW of freeway and highway charging at a total estimated MAT 46H and 06H cost of \$113 million.²³⁵⁶

4.17.1.1.3 TURN's Proposed Reductions To Funding For Capacity Work Related To Agricultural Load Should Not Be Adopted

TURN recommends a 50 percent (\$30 million) reduction to the portion of PG&E's 2023 forecast in MATs 06A, 06H, 46A and 46H that TURN believes is associated with agricultural

²³⁵⁴ CALPA-06, p. 91, line 13 to p. 92, line 7.

²³⁵⁵ CALPA-06, p. 92, lines 17-27.

²³⁵⁶ PG&E-17, p. 17-8, line 8 to p. 17-9, line 3.

load. TURN claims that new or increased agricultural load, primarily due to indoor cannabis cultivation and well pumping, is a key driver of capacity programs.²³⁵⁷ TURN argues that PG&E's forecast overestimates the future impacts of agricultural load on peak demand because it does not account for the impact of Time of Use (TOU) rates. TURN estimates the portion of the 2023 forecast in MATs 06A, 06H, 46A and 46H that is associated with agricultural load as \$60 million. TURN's estimate, based on review not only of specific projects included in the forecast but also of projects identified subsequent to the forecast, is that 50 percent of MAT 06H and 46H work and 20 percent of MAT 06A and 46A work is attributable to agricultural load.²³⁵⁸

TURN's arguments are flawed. First, as explained in detail in PG&E's rebuttal, more than half of the cannabis and agricultural pumping projects that form the basis for TURN's recommended cost reductions are not included in the 2023 GRC forecast. These projects were emergent projects identified after the creation of the forecast but listed in PG&E's workpapers and included in discovery for completeness and alignment with the 2021 Distribution Investment Deferral Framework process and the 2021 Grid Needs Assessment and Distribution Deferral Opportunity Reports. The 2023 forecast for the six agricultural and cannabis projects actually included in the GRC forecast is \$25.7 million. This represents 18% of the MWC 46A, 46H, 06A, and 06H forecast of \$139.0 million, not 50%.²³⁵⁹

Second, PG&E disagrees with TURN's analysis of the anticipated effect of TOU rate changes on agricultural pumping loads. In its rebuttal testimony, PG&E presented evidence that that the adoption of TOU rates does not automatically correlate to measurable changes in load.²³⁶⁰

²³⁵⁷ TURN-10, p. 5, lines 11-14.

²³⁵⁸ TURN-10, p. 6, lines 1-20.

²³⁵⁹ PG&E-17, p. 17-12, line 1 to p. 17-13, line 8.

²³⁶⁰ PG&E-17, p. 17-13, line 9 to p. 17-14, line 3.

Third, PG&E disagrees with TURN's conclusions regarding the effect of TOU rate shifts on reducing cannabis customer loads. Because cannabis cultivation is highly localized, it tends to overwhelm local distribution infrastructure, regardless of the time of peak. New cannabis loads are often large in comparison to existing loads and infrastructure. As a result, these new loads cause grid deficiencies, irrespective of whether the load hits the system at peak hours. Also, given that the main driver for cannabis growers is the speed with which the product can be brought to market, there is no evidence that they are sensitive to electricity rates. PG&E provided examples illustrating these points in its rebuttal testimony.²³⁶¹

TURN's recommended funding level is insufficient. TURN is recommending a cost reduction based on several emergent cannabis projects that were not included in the 2023 GRC forecast and that are incremental to what the 2023 emergent project forecast can fund. The effect of this reduction would be to remove funding from other capacity projects in the GRC forecast that TURN, presumably, has no objection to. It would also remove funding that could be used for multiple new electric vehicle fast charging stations. These applications for service were received after the 2023 GRC was filed, and the emergent capacity forecast in the GRC is insufficient to cover these projects. The six largest EV projects enable 195 MW of freeway and highway charging at a total MAT 46H and 06H cost of \$113 million.²³⁶²

4.18 New Business And Work At The Request Of Others

4.18.1 PG&E's Expense And Capital Forecast

PG&E's TY 2023 expense forecast as presented in rebuttal testimony is \$24.161 million²³⁶³ and is uncontested. PG&E's TY 2023 forecast in the JCE, including the September

²³⁶¹ PG&E-17, p. 17-14, lines 4 to p. 17-15, line 19.

²³⁶² PG&E-17, p. 17-15, line 22 to p. 17-16, line 6.

²³⁶³ PG&E-17, p. 18-3, Table 18-1, line 3.

escalation adjustment, is \$26.811 million.²³⁶⁴ Expense work is tracked in MWC EV, New Business Service Inquiry, and MWC EW, Work at the Request of Others (WRO).

PG&E capital expenditures forecast presented in rebuttal testimony is \$667.558 million in 2021, \$745.170 million in 2022, \$781.194 million in 2023, \$841.719 million in 2024, \$913.712 million in 2025, and \$978.178 million in 2026.²³⁶⁵ PG&E's capital expenditures forecast, including the September escalation adjustment, is \$688.226 million in 2021, \$812.299 million in 2022, \$882.370 million in 2023, \$983.700 million in 2024, \$1,070.751 million in 2025, and \$1,120.770 million in 2026.²³⁶⁶ PG&E's capital work is tracked in MWC 10, Electric Distribution WRO General, and MWC 16, Electric Distribution Customer Connects.

4.18.2 Electric Distribution WRO General (MWC 10)

PG&E's forecast for work in MWC 10 in its initial testimony included costs for upgrading two substations to allow for the electrification of the Caltrain system.²³⁶⁷ The forecast for this work was later moved to Track 2 of the GRC. Parties' did not oppose PG&E's remaining forecast for MWC 10.

4.18.3 Electric Distribution Customer Connects (MWC 16)

Work in MWC 16 consists of installing the electric infrastructure required to connect new customers to PG&E's distribution system or to accommodate increased load from existing customers.²³⁶⁸ PG&E's capital forecast for MWC 16 and Cal Advocates' and TURN's recommended reductions are summarized below.

²³⁶⁴ PG&E-64, p. 3-2, Table 3A-1, lines 80-81.

²³⁶⁵ PG&E-17, p. 18-20, Table 18-5, line 3.

²³⁶⁶ PG&E-64, p. 3-11, Table 3B-2, lines 65-67 (2022); p. 3-7, Table 3B-1, lines 65-67 (2023). The 2021 forecast is confidential – see PG&E-64, p. 3-15, Table 3B-3, lines 65-67 (2021). PG&E-67, WP-3, lines "[Exhibit 4, Chapter] 18," MWCs 10 and 16 (2021).

²³⁶⁷ PG&E-04, p. 18-46, lines 19-27.

²³⁶⁸ PG&E-04, p. 18-10, line 4 to p. 18-14, line 8.

**TABLE 4-46:
ELECTRIC DISTRIBUTION CUSTOMER CONNECTS – PG&E’S CAPITAL FORECAST AND
PARTIES RECOMMENDED (REDUCTIONS)/INCREASES (\$000s)^(a)**

Party	2020	2021	2022	2023	2024	2025	2026
PG&E	\$536,190	\$511,868	\$600,122	\$648,425	\$701,877	\$762,885	\$801,837
Cal Advocates		\$110,183	\$(62,377)	\$(55,068)			
TURN				\$(54,770)	\$(75,368)	\$(96,676)	\$(84,237)
(a) PG&E-17, p. 18-4, Table 18-2, line 11; p. 18-20, Table 18-5, line 2; p. 18-21, Table 18-6, lines 1-9.							

The parties make recommendations for four areas of MWC 16: Residential Connects (Cal Advocates and TURN), Non-Residential Connects (Cal Advocates), Plug-in Electric Vehicles (TURN); and Transformer Purchases (Cal Advocates). These four areas are addressed below.

4.18.3.1 Residential Connects

Residential Connects captures the costs of building new underground and overhead primary electric distribution systems, and the associated secondary systems and services to residential customers.²³⁶⁹ PG&E’s Residential (and Non-Residential) connections forecast is based in part on the forecast of the number of new residential (and non-residential) connections prepared by an outside consultant, the Rosen Consulting Group (RCG).²³⁷⁰ RCG’s econometric model (Utility Connects), which PG&E has employed for several GRCs, uses various dependent and independent variables to derive its forecasts.²³⁷¹

Cal Advocates proposes increases to PG&E’s 2022 and 2023 capital forecast for Residential Connects. Cal Advocates conducted an analysis of PG&E’s historical residential connections data and developed “adjustment factors,” which it applied to PG&E’s new connections forecast to arrive at its forecast that is slightly higher than PG&E’s forecast in those same years.²³⁷²

²³⁶⁹ PG&E-04, p. 18-12, line 1 to p. 18-13, line 6; p. 18-25, line 3 to p. 18-27, Table 18-14.

²³⁷⁰ PG&E-17, p. 18-AtchA-1 to p. 18-AtchA-5.

²³⁷¹ PG&E-17, p. 18-6, lines 4-9.

²³⁷² PG&E-17, p. 18-6, lines 9-25.

PG&E's rebuttal testimony explains in detail why Cal Advocates' approach is not statistically sound. In particular, Cal Advocates does not recognize that the results of RCG's Utility Connects model do not represent a single model run performed at one time with one set of data but rather combines the results of multiple runs of the Utility Connects model performed at different points in time with different data to produce the cited forecasts. Using one forecast year from one model run and appending the next forecast year from a different model run, when different data were available, as Cal Advocates has done, is inappropriate. Cal Advocates does not appear to have made any type of adjustment to account for historical revisions in data and is likely overstating the differences between the forecasts and actual connects.²³⁷³ By contrast, RCG periodically recalibrates its Utility Connects model in a way that adjusts for revisions to historical data and for variances between prior runs of the model and actual historical results.²³⁷⁴

TURN proposes reductions to PG&E's 2023-2026 capital forecasts, noting that PG&E's 2023 forecast is significantly higher than historical amounts.²³⁷⁵ TURN criticizes the forecast number of permits used in the RCG Utility Connects model and recommends reductions based on substituting its own forecast for permits based on historical averages.

TURN has two main criticisms of the permit forecast. First, while PG&E shared most of the details of the RCG new connects model with TURN, RCG considers its separate and distinct model for forecasting the number of permits proprietary and confidential and PG&E did not provide it to TURN. TURN claims that PG&E's failure to provide this information denies the Commission and intervenors the ability to examine a key driver of PG&E's cost increase request for new connections.²³⁷⁶ Second, TURN questions the reasonableness of RCG's significant

²³⁷³ PG&E-17, p. 18-7, lines 2-15; p. 18-AtchA-4.

²³⁷⁴ PG&E-17, p. 18-7, lines 26-28.

²³⁷⁵ PG&E-17, p. 18-8, lines 18-29.

²³⁷⁶ TURN-08, p. 13, lines 9-13.

forecast increase in permits given the many supply constraints on the residential housing market such as local anti-development efforts (i.e., NIMBYism), high land and labor costs, and supply chain issues.²³⁷⁷

TURN's assertion that PG&E did not share sufficient details about RCG's models is incorrect. PG&E shared a full version the RCG Utility Connects Model, which is what PG&E's connections forecast is based on. Although PG&E was not able to share a full version of RCG's proprietary Independent Variables (IV) model, PG&E shared information in its workpapers and discovery responses representing approximately 90 percent of a completed connects model. In addition, PG&E and RCG met with TURN and Cal Advocates representatives on three separate occasions to answer questions about the Utility Connects model and IV model.²³⁷⁸

Moreover, RCG also provided narrative explanations about the basis for its permits forecast in a whitepaper included in PG&E's workpapers²³⁷⁹ and another whitepaper included with PG&E's rebuttal testimony.²³⁸⁰ These whitepapers note that factors including the end of COVID-19 restrictions, strong consumer demand, and incentives for developers to increase the pace of development all are likely to contribute to a significant growth in permitting in the 2023 GRC cycle.²³⁸¹ These factors support PG&E's forecast.

PG&E also disagrees with TURN's claim that the forecast number of permits from the RCG model, which is higher than historical permitting rates, is unreasonable given the difficulties of developing housing in California. RCG points to both increased housing need and

²³⁷⁷ TURN-08, p. 14, line 1 to p. 15, line 8.

²³⁷⁸ PG&E-17, p. 18-10, lines 11-20.

²³⁷⁹ PG&E-04, WP 18-29 to WP 18-41.

²³⁸⁰ PG&E-17, p. 18-AtchA-3.

²³⁸¹ PG&E-17, p. 18-10, line 22 to p. 18-12, line 12.

a more development-friendly legislative environment as drivers for an increased rate of permitting.²³⁸²

PG&E also disagrees with TURN's recommendation because its use of a 5-year (2015-2019) average is simplistic and, unlike the RCG permits model, does not account for likely changes in the economy between that period and the 2023 GRC period.²³⁸³ Another consideration that supports PG&E's forecast is that in 2021 PG&E already reached the level of residential connections spending it was expecting to reach in 2023. PG&E's 2021 recorded spending for residential connections was \$256.7 million,²³⁸⁴ significantly higher than PG&E's 2021 forecast of \$167.5 million.²³⁸⁵ PG&E's 2021 recorded spending is about equal to PG&E's 2023 forecast spending of \$261.6 million²³⁸⁶ and is approximately \$54 million more than TURN's recommendation for 2023.²³⁸⁷

4.18.3.2 Non-Residential Connects

Non-Residential Connects captures the costs of building new underground and overhead primary electric distribution systems, and the associated secondary systems, and services to non-residential customers.²³⁸⁸

Similar to its argument above for Residential connections, Cal Advocates claims that PG&E's forecast for Non-Residential connections has not tracked historical outcomes very well

²³⁸² PG&E-17, p. 18-12, lines 16-18.

²³⁸³ PG&E-17, p. 18-10, lines 5-8.

²³⁸⁴ PG&E's Email Transmittal of the 2021 Recorded Expense and Capital Data to Service List A.21-06-021 (Mar. 9, 2022), Attachment 3, 2021 Recorded Capital Tables, p. 11, MAT Summary (Residential Connections are tracked in MATs 166, 167, 16B, 16C, 16D, 16O, 16P, 16Q, 16R, 16S and 16Y).

²³⁸⁵ PG&E-04, WP 18-25, line 1.

²³⁸⁶ PG&E-04, WP 18-25, line 1.

²³⁸⁷ TURN-08C, p. 2, Table 1 (TURN recommendation for 2023 of \$207.7 million for Residential New Connections).

²³⁸⁸ PG&E-04, p. 18-13, lines 7-11; and, p. 18-28, line 1 to p. 18-29, Table 18-15.

and has applied an adjustment factor to the forecast for 2022 and 2023 to derive its own connections forecast.²³⁸⁹ The Commission should not adopt Cal Advocates' recommendation. For the reasons explained above in Section 4.18.3.1, Cal Advocates' methodology for arriving at its proposed adjustments to PG&E's Non-residential Connects forecast is unsupported and not statistically valid. As with Residential connections, another factor supporting PG&E's forecast as opposed to Cal Advocates' proposed reduction is that PG&E's 2021 recorded spending for non-residential connections was significantly higher than forecast, and in fact higher than PG&E's 2023 forecast.²³⁹⁰

4.18.3.3 Plug-In Electric Vehicles (PEV)

PEV captures the costs of all distribution transformer, secondary and service upgrade work to serve increased loads related to PEVs. The portion of the forecast that is relevant to this section is for utility-side distribution costs ("to the meter" or TTM) related to PG&E's Electric Vehicle Charge 2 (EVC 2) Application.²³⁹¹

TURN proposes that PG&E's 2023-2026 capital forecast for the EVC 2 portion of MWC 16 be reduced to match the number of charging ports that PG&E is authorized in the EVC 2 Application proceeding.²³⁹² The Commission should adopt part but not all of TURN's recommendation. PG&E agrees that the forecast scope and timing of work and unit costs presented in PG&E's EVC 2 application are a better basis for PG&E's GRC forecast than the forecast presented in PG&E's prepared GRC testimony. PG&E is willing to adopt its EVC 2 forecast as its GRC forecast for the EVC 2 activity in MWC 16 and has reduced its forecast accordingly. However, PG&E does not agree with TURN's proposal that PG&E's GRC funding be based on the number of charging ports ultimately authorized in the EVC 2 proceeding.

²³⁸⁹ CALPA-05, p. 41, lines 13-24.

²³⁹⁰ PG&E-17, p. 18-14, line 27 to p. 18-15, line 6.

²³⁹¹ PG&E-04, p. 18-13, lines 16-28e; p. 18-30, line 1 to p. 18-32, Table 18-16.

²³⁹² TURN-08, p. 1, lines 11-12.

Although a decision on PG&E's EVC 2 application is due in Q4 2022 under the current schedule, there is no guarantee that that schedule will hold such that the authorized number of charging ports could be timely included in PG&E's capital forecast. A GRC forecast based on PG&E's EVC 2 application forecast is reasonable under these circumstances.

4.18.3.4 Transformer Purchases

PG&E purchases all the distribution transformers that are part of any PG&E capital project through the Transformer Purchases activity in MWC 16.²³⁹³ Cal Advocates proposes a reduction to PG&E's capital forecasts for 2022 and 2023. Cal Advocates does not object to PG&E's forecast methodology but recommends reductions to PG&E's Transformer Purchases forecast proportionate to Cal Advocates' recommended reductions to the forecast for three Electric line of business activities—Pole Replacement (MWC 07), New Business (MWC 16) and Major Emergency (MWC 95)—that use transformers.²³⁹⁴

Cal Advocates' recommended reduction for Transformer Purchases should not be adopted because the other proposed reductions – to MWCs 07, 16, and 95 – upon which it depends should not be adopted. PG&E explains why it does not agree with Cal Advocates' proposed recommendations for MWCs 07, 16, and 95 elsewhere in this brief.²³⁹⁵

4.19 Rule 20A

PG&E capital expenditures forecast presented in rebuttal testimony is \$47.288 million in 2021, \$39.954 million in 2022, \$39.876 million in 2023, \$40.957 million in 2024, \$42.060 million in 2025, and \$43.204 million in 2026.²³⁹⁶ PG&E's capital expenditures forecast, including the September escalation adjustment, is \$48.752 million in 2021, \$43.553 million in 2022, \$45.040 million in 2023, \$47.866 million in 2024, \$49.288 million in 2025, and \$49.501

²³⁹³ PG&E-04, p. 18-13, line 29 to p. 18-14, line 5; p. 18-33, line 1 to p. 18-34, Table 18-17.

²³⁹⁴ CALPA-05, p. 44, line 21 to p. 46, line 4.

²³⁹⁵ See Sections 4.12.1.2 (MWC 07), 4.18.3.2 (MWC 16) 4.6.13 (MWC 95).

²³⁹⁶ PG&E-17, p. 19-7, Table 19-3, line 2.

million in 2026.²³⁹⁷ PG&E's capital work is tracked in MWC 30, Work at the Request of Others, Rule 20A.

The Rule 20A program in MWC 30 allows governmental agencies to underground existing overhead electric facilities that meet certain criteria related to reducing overhead lines in high traffic and scenic areas.²³⁹⁸ The program is funded through a one-way balancing account established in the 2017 GRC and both the 2017 and 2020 GRC decisions provided that any over-collected balance in the account would remain available for future Rule 20A projects and that the Commission would review the balance in the next GRC proceeding.²³⁹⁹ PG&E's 2022 forecast is based on a 3-year average (2018-2020).

PG&E's capital forecast for MWC 30 and Cal Advocates' and TURN's recommended reductions are summarized below.

TABLE 4-47:
RULE 20A - PG&E'S CAPITAL FORECAST AND PARTIES RECOMMENDED
(REDUCTIONS)/INCREASES (\$000s)^(a)

Party	2020 Rec.	2021	2022	2023	2024	2025	2026
PG&E	\$38,273	\$47,288	\$39,954	\$39,876	\$40,957	\$42,060	\$43,204
Cal Advocates(b)		\$(9,470)					
TURN		\$(9,470)	\$(11,790)	\$(10,700)	\$(10,742)	\$(10,777)	\$(10,824)
(a) PG&E-17, p. 19-7, Table 19-3, line 1; p. 19-3, Table 19-1, line 1; PG&E-64, p. 2-314, Section 2. . (b) Cal Advocates recommends using PG&E's 2021 recorded costs in place of its 2021 forecast. This is addressed in Appendix A.							

TURN believes that the 2018-2020 forecast period used by PG&E was volatile and spending was unusually high in 2019. TURN instead uses a 5-year (2017-2021) average, plus escalation, which results in a forecast that is lower than PG&E's forecast.²⁴⁰⁰ In addition to this baseline adjustment, TURN recommends that one-fifth of the existing balance of the Rule 20A

²³⁹⁷ PG&E-67, WP 3, line "[Exhibit 4, Chapter] 19," MWC 30.

²³⁹⁸ PG&E-04, p. 19-4, line 3 to p. 19-5, line 8.

²³⁹⁹ PG&E-04, p. 19-8, lines 12-20.

²⁴⁰⁰ TURN-15, p. 4, lines 5-13.

balancing account (as of the end of 2021) should be applied to the forecasts for 2022-2026.²⁴⁰¹ This would further reduce PG&E's forecast by approximately \$9.3 million per year. TURN notes that this treatment of a Rule 20A balancing account is consistent with the treatment adopted in SCE's recent GRC decision (D.21-08-036).²⁴⁰²

The Commission should not adopt TURN's recommendations. First, the three-year (2018-2020) average used by PG&E as the basis for its forecast is more reasonable than the five-year average (2017-2021) average used by TURN. PG&E's recorded costs increased every year from 2017 to 2019; 2020 and 2021 recorded costs, while lower than 2019 recorded costs, were still much higher than both 2017 and 2018 costs.²⁴⁰³ TURN's use of a five-year average starting in 2017 gives too much weight to PG&E's relatively low spending in 2017 and 2018. PG&E's three-year (2018-2020) average more accurately represents the direction of the program and is more consistent with PG&E's 2021 spending of \$37.8 million than TURN's approach.²⁴⁰⁴

Second, TURN's further reduction based on its proposal that the entire balance of the existing Rule 20A balancing account be spent down by the end of 2026 should not be adopted. PG&E's forecast already accounts for a spend down of a significant portion of the balancing account balance. In addition, PG&E has many more potential Rule 20A projects in the queue than it currently has the resources to complete and adopting TURN's recommendation would make the problem worse. Any remaining funds in the balancing account will provide flexibility

²⁴⁰¹ TURN-15, p. 5, lines 2-16. PG&E notes that the Rule 20A balancing account balance as of the end of 2021 is higher than what PG&E estimated in GRC testimony because PG&E spent less than forecast in the Rule 20A program in 2021. *See* Tr. Vol. 12, 2265:27 to 2267:1, PG&E/Norimoto.

²⁴⁰² TURN-15, p. 5, lines 10-13.

²⁴⁰³ PG&E-17, PG&E's response to Data Request TURN_127-Q01, dated 3/03/22, p. App A-243. PG&E-04, WP 19-8, line 9 (2017-2021 recorded costs).

²⁴⁰⁴ PG&E-17, p. 19-5, lines 11-15.

to perform more project work than forecast if resources become available.²⁴⁰⁵ The fact that SCE's recent GRC decision provided for SCE spending down the entire balance of its one-way balancing account does not mean that the Commission should adopt the same approach here. As PG&E's witness Tamon Norimoto explained at hearings, PG&E has a much larger number of Rule 20A projects in its queue than SCE does.²⁴⁰⁶

4.20 Electric Distribution Data Management And Technology

4.20.1 PG&E's Expense And Capital Forecast

PG&E's TY 2023 expense forecast as presented in rebuttal testimony is \$26.026 million.²⁴⁰⁷ PG&E's TY 2023 forecast in the JCE, including the September escalation adjustment, is \$30.908 million.²⁴⁰⁸ Expense work is tracked in MWC GE, Electric Distribution Mapping, and in MWC JV, Maintain IT Applications and Infrastructure.

PG&E capital expenditures forecast as presented in rebuttal testimony is \$17.696 million in 2021, and \$23.605 million in 2022, \$19.700 million in 2023, \$18.421 million in 2024, \$18.448 million in 2025, and \$20.591 million in 2026.²⁴⁰⁹ PG&E's capital expenditures forecast, including the September escalation adjustment, is \$18.236 million in 2021, \$27.408 million in 2022, \$23.839 million in 2023, \$22.324 million in 2024, \$22.068 million in 2025, and \$24.318 million in 2026.²⁴¹⁰ PG&E's capital work is tracked in MWC 2F, Build IT Applications and Infrastructure and in MWC 21, Miscellaneous Capital. PG&E's capital forecast is uncontested. See Appendix A.

²⁴⁰⁵ PG&E-17, p. 19-5, lines 15-23.

²⁴⁰⁶ Tr. Vol. 12, 2279:2 to 2280:22, PG&E/Norimoto; PG&E-65 (showing differences between PG&E's and SCE's Rule 20A project queues).

²⁴⁰⁷ PG&E-17, p. 20-3, Table 20-1, line 3.

²⁴⁰⁸ PG&E-64, p. 3-2, Table 3A-1, lines 82-83.

²⁴⁰⁹ PG&E-17, p. 20-14, Table 20-5, line 3.

²⁴¹⁰ PG&E-67, WP 3, lines "[Exhibit 4, Chapter] 20," MWCs 01, 21 and 2F.

The disputed expense forecasts are addressed below.

4.20.2 Electric Distribution Mapping (MWC GE)

The work in Electric Distribution Mapping involves the maturation of capabilities and management of core data quality and systems/platforms (e.g., GIS, SAP AG Software (SAP), Foundry) to provide asset information that is accurate, traceable, verifiable, and complete and to enable effective data-driven decisions for asset and risk management.²⁴¹¹ PG&E's forecast for MWC GE and Cal Advocates' recommended reductions are summarized below.

**TABLE 4-48:
ELECTRIC DISTRIBUTION MAPPING - PG&E'S EXPENSE FORECAST AND PARTIES
RECOMMENDED REDUCTIONS (\$000s)^(a)**

Party	2020 Rec.	2021	2022	2023
PG&E	\$8,845	\$15,888	\$14,108	\$21,524
Cal Advocates				(12,697)
(a) PG&E-17, p. 20-3, Table 20-1, line 1; p. 20-14, Table 20-4, line 1.				

Cal Advocates contends that the work forecast in MWC GE for GIS Asset Data Improvement is just a re-named version of the Field Asset Inventory (FAI) project, which has already been funded several times in prior GRCs and deferred each time.²⁴¹² Cal Advocates argues that even if PG&E appropriately reallocated its previously authorized funding for FAI to higher priority projects, those other projects were funded in other proceedings so PG&E should not be able to ask for funding again.²⁴¹³ Cal Advocates recommends that PG&E's expense forecast for MWC GE should be based on PG&E's 2020 recorded costs of \$8.8 million, in part because customers should not be required to fund a project that had been funded in prior GRCs and subsequently deferred.²⁴¹⁴

²⁴¹¹ PG&E-04, p. 20-8, lines 8-13.

²⁴¹² CALPA-04, p. 32, lines 5-13.

²⁴¹³ CALPA-04, p. 32, line 14 to p. 34, line 16.

²⁴¹⁴ CALPA-04, p. 34, lines 14-16.

The Commission should not adopt Cal Advocates’ recommendation to base PG&E’s 2023 forecast for MWC GE on PG&E’s 2020 recorded costs. The 2023 forecast for MWC GE is significantly higher than 2020 recorded costs primarily due to the required implementation of PG&E’s Next Gen GIS project beginning in 2023, as well as an increased number of updates to the asset registry stemming from PG&E’s implementation of enhanced inspections.²⁴¹⁵ Both of these efforts are new since the 2020 GRC. PG&E also anticipates higher costs in 2023 to implement the electric data strategy, which will be led by the Data Management and Analytics organization.²⁴¹⁶ Cal Advocates did not make any specific criticisms of or recommendations about any of these programs.

Cal Advocates’ argument that the work forecast in MWC GE for GIS Asset Data Improvement should not be funded because it is a re-named version of the FAI is mistaken in several respects. First, as PG&E explained in its rebuttal testimony, only \$3.2 million of PG&E’s 2023 Asset Data Improvement forecast relates to activities that are intended to accomplish the goals of the original FAI project; the rest of the forecast relates to other asset information gathering activities unrelated to the original FAI project.²⁴¹⁷ Second, when PG&E cancelled the previously funded FAI project, it performed other valuable work instead – “the cancellation of the Field Asset Inventory project allowed PG&E to narrow and align the focus of work to distribution wildfire data improvement by using LiDAR to improve the spatial location of our distribution structures and lines.”²⁴¹⁸ Cal Advocates argues that this work was funded in the 2020 Wildfire Mitigation and Catastrophic Events (2020 WMCE) proceeding but, as PG&E explained in rebuttal, this claim is mistaken; no MWC GE work was funded through the 2020

²⁴¹⁵ PG&E-04, p. 20-13, lines 7-10.

²⁴¹⁶ PG&E-04, p. 20-9, lines 13-16.

²⁴¹⁷ PG&E-17, p. 20-6, lines 9-20.

²⁴¹⁸ PG&E-17, PG&E’s response to data request CalAdvocates_107-Q06(h), dated 10/21/21, p. App A-245.

WMCE.²⁴¹⁹ Cal Advocates’ proposed \$12.7 million reduction to MWC GE would prevent PG&E from executing key initiatives that are critical for managing and maintaining core data quality systems and platforms.

4.20.3 Maintain IT Applications And Infrastructure (MWC JV)

The work in MWC JV includes the portfolio technology investments needed to improve capabilities related to asset and work management, customer service, and billing and rates.²⁴²⁰ PG&E’s forecast for MWC JV and Cal Advocates’ recommended reductions are summarized below.

**TABLE 4-49:
MAINTAIN IT APPLICATIONS AND INFRASTRUCTURE - PG&E’S EXPENSE FORECAST
AND PARTIES RECOMMENDED REDUCTIONS (\$000s)^(a)**

Party	2020 Rec.	2021	2022	2023
PG&E	\$2,810	\$3,777	\$3,333	\$4,501
Cal Advocates				\$(1,062)
(a) PG&E-17, p. 20-3, Table 20-1, line 2; p. 20-14, Table 20-4, line 2.				

Cal Advocates used a three-year average of PG&E’s 2018-2020 recorded adjusted expenses to develop its forecast for MWC JV. Cal Advocates states that their recommendation addresses the variability in PG&E’s Information Technology expenses and the historic reallocation of its authorized revenues.²⁴²¹

Cal Advocates’ position is unreasonable. PG&E provided a bottom-up forecast for MWC JV based on the types of projects that PG&E anticipates a need for in the GRC period. PG&E’s testimony and workpapers provide detail on each proposed technology project/capability.²⁴²² For example, PG&E noted that its 2023 expense forecast for the Field Work Management value stream was \$2.2 million more than 2020 recorded due to “increased

²⁴¹⁹ PG&E-17, p. 20-7, line 27 to p. 20-9, line 9.

²⁴²⁰ PG&E-04, p. 20-1, lines 19-21.

²⁴²¹ CALPA-04, p. 34, lines 24-27.

²⁴²² PG&E-04, p. 20-24, line 1 to p. 20-38, Table 20-18; PG&E-04, WP 20-32 to WP 20-47.

investment in expanded digitization of design and estimating toolsets and the development of software tools for new service application work-planning and scheduling.”²⁴²³ Similarly, PG&E forecast a \$0.9 million increase relative to 2020 in the Safety, Governance, Regulatory and Compliance value stream in order to “[maintain] the EO Mobile and Offline Document Viewer.”²⁴²⁴

Cal Advocates’ testimony did not dispute the viability or need for any of PG&E’s electric distribution technology projects. The Commission should not adopt Cal Advocates’ recommended funding level for MWC JV because a three-year average of 2018-2020 recorded costs does not provide sufficient funding for PG&E to complete its forecast work.

4.21 Integrated Grid Platform And Grid Modernization Plan

4.21.1 PG&E’s Expense And Capital Forecast

PG&E’s TY 2023 expense forecast presented in rebuttal testimony is \$38.593 million. PG&E’s TY 2023 forecast in the JCE, including the September escalation adjustment, is \$44.879 million.²⁴²⁵ PG&E tracks expense work in five MWCs, four of which are uncontested (MWCs AB, HG, IG and JV). See Appendix A.

PG&E capital expenditures forecast as reflected in rebuttal testimony is \$220.390 million in 2021, \$192.917 million in 2022, \$131.655 million in 2023, 88.981 million in 2024, \$42.163 million in 2025, and \$43.438 million in 2026. PG&E’s capital expenditures forecast, including the September escalation adjustment, is \$236.983 million, \$211.786 million in 2022, \$150.528 million in 2023, \$104.894 million in 2024, \$49.035 million in 2025, and \$50.369 million in 2026.²⁴²⁶ PG&E tracks capital work in five MWCs, three of which are uncontested (MWCs 21, 2F, 3R, and 82). See Appendix A.

²⁴²³ PG&E-04, p. 20-27, lines 6-9.

²⁴²⁴ PG&E-04, p. 20-35, lines 5-8.

²⁴²⁵ PG&E-67, WP 16, lines 85-89.

²⁴²⁶ PG&E-67, WP 3, lines “[Exhibit 4, Chapter] 21,” MWCs 21, 63, 82, 2F, 3M and 3R.

The contested expense and capital MWCs are addressed below.

4.21.2 Emerging Technology (MWC AT)

The Electric Emerging Technology Program in MWC AT will fund and administer a series of external innovation partnerships to keep PG&E informed of the external technology landscape and industry trends, and facilitate coordination with industry, academia, and other external groups to identify and apply technology solutions that address PG&E's greatest challenges. PG&E's forecast for MWC AT and Cal Advocates' recommended reductions are summarized below.

**TABLE 4-50:
EMERGING TECHNOLOGIES - PG&E'S EXPENSE FORECAST AND
PARTIES RECOMMENDED REDUCTIONS (\$000s)^(a)**

Party	2020 Rec.	2021	2022	2023
PG&E	\$0	\$0	\$0	\$2,056
Cal Advocates				\$(2,056)
(a) PG&E-17, p. 21-4, Table 20-1, line 2; p. 21-18, Table 21-4, line 2.				

Cal Advocates recommends de-funding the Electric Emerging Technology program because they assert it is already funded through EPIC.²⁴²⁷ PG&E has already removed \$15.1 million from its MWC AT forecast to reflect the Commission's decision to allow PG&E to continue administering its EPIC program. The \$2.1 million remaining in the forecast corresponds to the External Innovation Partnerships program, which is not funded through EPIC.²⁴²⁸ Cal Advocates does not provide any rationale for de-funding the External Innovation Partnerships program.

²⁴²⁷ PG&E-17, p. 21-16, lines 5-7.

²⁴²⁸ PG&E-17, p. 21-16, lines 10-19. For a more detailed description of the External Innovation Partnerships program, see PG&E-04, WP 21-52 to WP 21-53.

4.21.3 Electric Distribution Operations, Advanced Distribution Management System (ADMS) And Distributed Energy Resources Management System (DERMS) (MWC 63)

The ADMS project will replace PG&E’s existing Real-Time Supervisory Control and Data Acquisition (RT-SCADA), Outage Management System (OMS), and Distribution Management System (DMS) control center applications with a single, integrated ADMS application. The ADMS project is divided into several workstreams including three “releases” that support different functionality. The primary scope of Release 1 is replacing RT-SCADA, the primary scope of Release 2 is replacing OMS, and the primary focus of Release 3 is to enable advanced applications within the ADMS platform.²⁴²⁹

DERMS will provide an ADMS-integrated solution for managing the operational complexity of distributed energy resources (DERs) on the PG&E grid. Capabilities provided by the DERMS will include DER monitoring, dispatch, constraint management, situational awareness, and program management. DERMS will also provide a platform for operation of DER-based deferral and resilience solutions.²⁴³⁰ PG&E’s capital forecast for MWC 63 and Cal Advocates’ recommended reductions are summarized below.

**TABLE 4-51:
ADMS AND DERMS - PG&E’S CAPITAL FORECAST AND PARTIES RECOMMENDED
(REDUCTIONS)/INCREASES (\$000s)^(a)**

Party	2020 Rec.	2021	2022	2023	2024	2025	2026
PG&E	\$44,373	\$81,885	\$126,880	\$109,049	\$68,042	\$20,565	\$26,438
Cal Advocates		\$(34,938)	\$(84,861)	\$(52,638)	\$(12,871)	\$(20,565)	\$(26,438)
(a) PG&E-17, p. 21-5, Table 21-2, lines 3-5; p. 21-19, Table 21-5, lines 3-5; p. 21-20, Table 21-6, lines 3-5.							

Cal Advocates recommends that capital forecasts for DERMS and ADMS Release 3, which together total \$27.4 million in TY 2023, be removed from the GRC and evaluated in a separate proceeding coordinated with the High DER Rulemaking proceeding (R.21-06-017).²⁴³¹

²⁴²⁹ PG&E-04, WP 21-18 to WP 21-30.

²⁴³⁰ PG&E-04, WP 21-31 to WP 21-34.

²⁴³¹ CALPA-06, p. 106, lines 18-22.

Cal Advocates argues that because the scope of DERMS and ADMS Release 3 has dependencies on outcomes of the High DER Rulemaking proceeding, these programs should be evaluated in the context of that proceeding, not the GRC.²⁴³² Specifically, Cal Advocates is concerned that PG&E’s DERMS cannot perform “economically-optimal dispatch of DER,” which is a feature of DERMS that may be required depending on how the High DER Rulemaking proceeding scopes the role of Distribution System Operator.²⁴³³

Cal Advocates also recommends that the ADMS Release 1 and 2 forecasts should be limited to a rate of spending based on PG&E’s 2020 GRC ADMS forecast, which would result in a \$24.9 million reduction to PG&E’s TY 2023 forecast for these releases.²⁴³⁴

There are several reasons why the Commission should not adopt Cal Advocates’ recommendation to remove the forecasts for DERMS and ADMS Release 3 from the GRC. First, this approach would be inconsistent with D.18-03-023, which provided IOUs with guidance regarding Grid Modernization issues to inform future GRCs.²⁴³⁵ Ordering Paragraph 4 of D.18-03-023 states that “the IOUs shall present their [Grid Modernization Plans] in the GRC for review and evaluation.”²⁴³⁶ Removing DERMS and ADMS Release 3, which are part of PG&E’s Grid Modernization Plan, from the GRC would be inconsistent with D.18-03-023. Moreover, doing so prior to the conclusion of Track 3 of the High DER Proceeding would presuppose the outcome of that proceeding.²⁴³⁷

²⁴³² CALPA-06, p. 105, line 21 to p. 107, line 2.

²⁴³³ CALPA-06, p. 106, lines 8-14.

²⁴³⁴ CALPA-06, p. 111, lines 11-12; p. 112, lines 9-12.

²⁴³⁵ D.18-03-023, p. 2.

²⁴³⁶ D.18-03-023, p. 35, Ordering Paragraph (OP) 4.

²⁴³⁷ Track 3, Phase 2 of the High DER Rulemaking Proceeding is expected to conclude in the second quarter of 2024. Refer to R.21-06-017, *Assigned Commissioner’s Scoping Memo and Ruling* (Nov. 15, 2021) p. 9.

More importantly, neither ADMS Release 3 nor DERMS have significant dependencies on the High DER Rulemaking proceeding. ADMS Release 3 is focused on providing the foundational power flow modeling capability essential for any future DERMS system, regardless of requirements that may emerge from the High DER Rulemaking proceeding. Additionally, ADMS Release 3 has benefits to grid operations that go well beyond DERMS-based DER management. These additional benefits include load forecasting, fault location, constraint identification, automated switching recommendations, and automated adjustment of protection and regulation device settings (i.e., Volt-Var Optimization). PG&E would proceed with ADMS Release 3 even in the absence of plans to implement DERMS.²⁴³⁸ Similarly, PG&E’s proposed DERMS is mostly focused on providing foundational capabilities such as DER monitoring, dispatch, constraint management, and situational awareness that will be required for any future DERMS system.²⁴³⁹

In its testimony, Cal Advocates cited a specific concern about the alleged inability of PG&E’s proposed DERMS to perform “economically-optimal dispatch of DERs”; a feature of DERMS that Cal Advocates posits may be required depending on how the High DER Rulemaking proceeding scopes the role of Distribution System Operator.²⁴⁴⁰ But, as PG&E explained in a discovery response to Cal Advocates: “[Economic dispatch of DER] could be developed within DERMS if and when market conditions warrant. Specific functional requirements will depend on the evolving market rules for dispatch.”²⁴⁴¹ This example is representative of PG&E’s overall approach to its DERMS implementation, which is to focus on developing foundational capabilities required of any DERMS system in a platform that can

²⁴³⁸ PG&E-17, p. 21-11, lines 4-16.

²⁴³⁹ PG&E-17, p. 21-9, line 17 to p. 21-10, line 6.

²⁴⁴⁰ CALPA-06, p.106, lines 8-14.

²⁴⁴¹ PG&E-17, PG&E’s response to Data Request CalAdvocates_023-Q10(f), dated 8/27/21, pp. App A-260 to App A-261.

flexibly accommodate new rules or requirements, such as those that may arise from the High DER Rulemaking proceeding.

In addition, moving consideration of DERMS from PG&E's GRC to the High DER Rulemaking proceeding is not advisable because it will delay approval of PG&E's DERMS and the eventual realization of its benefits by at least three years and potentially more.²⁴⁴² To wait for the High DER Rulemaking procedure would delay both the start and implementation of DERMS significantly and create a marketplace imbalance in California by further delaying PG&E's DERMS deployment relative to SCE and SDG&E, who have already had their DERMS proposals approved by the Commission in previous GRCs.²⁴⁴³

The Commission should also not adopt Cal Advocates' recommendation to limit the ADMS Release 1 and 2 capital forecasts to a rate of spending based on the 2020 GRC ADMS forecast. Cal Advocates makes several arguments in support of limiting the ADMS Release 1 and 2 capital forecasts to a rate of spending based on the 2020 GRC ADMS forecast, including: (1) that the increase in total ADMS capital program cost between PG&E's 2020 and 2023 GRCs, which Cal Advocates calculates as ranging from \$291.5-\$430.4 million and characterizes as having "roughly" doubled, is not supported by an increase in program scope;²⁴⁴⁴ (2) that because PG&E did not quantify incremental benefits of its 2023 ADMS request compared to its 2020 ADMS request, PG&E's ADMS forecast does not meet the Grid Modernization decision requirement to demonstrate reasonableness of cost;²⁴⁴⁵ and (3) that PG&E's \$442.5 million

²⁴⁴² PG&E-17, p. 21-10, lines 10-25.

²⁴⁴³ PG&E-17, p. 21-10, line 25, 21-11, line 3. SCE's ADMS+DERMS system was approved in D.21-08-036, p. 652, Conclusion of Law (COL) 35; SDG&E's DERMS system was approved in D.13-05-010, p. 485.

²⁴⁴⁴ CALPA-06, p. 107, line 21; p. 108, lines 5-16.

²⁴⁴⁵ CALPA-06, p. 109, line 5 to p. 110, line 3.

ADMS capital program is expensive in comparison with SCE's \$250 million ADMS capital program.²⁴⁴⁶

As a preliminary matter, PG&E disagrees with Cal Advocates' calculation of the difference between PG&E's 2020 and 2023 forecasts for ADMS. Based on PG&E's calculations, which are shown in PG&E's rebuttal testimony, the ADMS capital cost increase since the time of the 2020 GRC should be calculated as \$177.9 million (a 67% increase).²⁴⁴⁷

PG&E's ADMS program funding should not be constrained by a cost estimate made in the early project stages. The 2020 GRC cost estimate was made in 2017, at the very outset of the ADMS project, before a software vendor had been selected or detailed design of the program had begun.²⁴⁴⁸ This early cost estimate was always understood to have uncertainty associated with it, evidenced by the fact that the program business case presented to senior PG&E leadership in February 2019 included a "High Case" cost of \$484.7 million (an amount similar to PG&E's 2023 GRC forecast).²⁴⁴⁹ Unlike the 2020 GRC forecast, the 2023 GRC forecast benefitted from cost insights gained through several years of program implementation experience. One such insight was a recognition that PG&E's OMS replacement cost (Release 2) would be higher than that of comparable utilities due to the highly complex and customized nature of PG&E's legacy OMS applications; indeed, OMS was by far the biggest driver of the cost increase between the two GRC filings.²⁴⁵⁰ PG&E's 2023 GRC forecast for ADMS is more developed than its 2020 GRC counterpart and should be the basis for funding.

²⁴⁴⁶ CALPA-06, p. 110, line 4 to p. 111, line 8.

²⁴⁴⁷ PG&E-17, p. 21-12, line 4 to p. 21-13, line 3.

²⁴⁴⁸ PG&E-17, p. 21-13, lines 26-29.

²⁴⁴⁹ PG&E-17, Ch. 21, Attachment A, "Major Project Business Case: Integrated Grid Platform: Advanced Distribution Management System (ADMA)," p. 004.

²⁴⁵⁰ PG&E-17, p. 21-14, lines 5-9.

PG&E does not agree with Cal Advocates’ assertion that because PG&E did not quantify incremental benefits of its 2023 ADMS request compared to its 2020 ADMS request, PG&E’s ADMS cost increase should be rejected because it does meet the Grid Modernization decision requirement to “demonstrate reasonableness of cost.” The scope of ADMS Release 1 and 2 is largely unchanged so there are negligible incremental benefits to be quantified. In any case, PG&E’s ADMS cost reasonableness showing has always been based on a qualitative, not quantitative, description of program benefits because these benefits are so varied and far-reaching as to preclude any reasonable method of comprehensive quantification.²⁴⁵¹

Finally, PG&E does not agree with Cal Advocates’ assertion that the lower cost of SCE’s ADMS program suggests that PG&E’s forecast ADMS costs are not reasonable. As PG&E explained in rebuttal, the two projects are fundamentally not comparable because PG&E’s scope includes fully replacing its distribution SCADA software with ADMS, whereas SCE proposes building OMS/Advanced Application/DERMS functionalities in an ADMS-ready SCADA platform. A comparison limited to activities that PG&E’s and SCE’s proposal have in common shows that their costs are similar.²⁴⁵²

Other than its cost concerns, Cal Advocates does not have any criticisms of ADMS and does not argue for reducing or changing its scope. PG&E would not be able to deliver the full ADMS Release 1 and 2 project scope with reduced funding. PG&E would likely have to delay further work on ADMS Release 2 until sufficient funding is approved in a future GRC. This would delay realization of the substantial reliability and operational efficiency benefits from integrating PG&E’s outage management applications into ADMS until approximately 2030.²⁴⁵³

²⁴⁵¹ PG&E-17, p. 21-13, lines 12-22.

²⁴⁵² PG&E-17, p. 21-14, lines 11-25.

²⁴⁵³ PG&E-17, p. 21-15, lines 3-22.

4.22 Electric Distribution Support

4.22.1 PG&E's Expense And Capital Forecast

PG&E's TY 2023 expense forecast presented in rebuttal testimony is \$131.594 million.²⁴⁵⁴ PG&E's TY 2023 forecast in the JCE, including the September escalation adjustment, is \$148.075 million.²⁴⁵⁵ PG&E tracks expense work in four MWCs, three of which are uncontested (MWCs IS, OM and OS). See Appendix A.

PG&E capital expenditures forecast presented in rebuttal testimony is \$(18.340) million in 2021, \$10.663 million in 2022, \$8.394 million in 2023, \$8.575 million in 2024, \$8.762 million in 2025, and \$8.956 million in 2026.²⁴⁵⁶ PG&E's capital expenditures forecast, including the September escalation adjustment, is \$(18.909) million in 2021, \$12.104 million in 2022, \$10.037 million in 2023, \$10.327 million in 2024, \$10.445 million in 2025, and \$10.525 million in 2026.²⁴⁵⁷ PG&E tracks capital work in two MWCS, MWC 05, Tools and Equipment and MWC 21, Miscellaneous Capital. PG&E's capital forecast is uncontested. See Appendix A.

The disputed expense MWC is addressed below.

4.22.2 Miscellaneous Expense (MWC AB)

The work in MWC AB enables the safe and efficient execution of distribution work across Electric Operations programs. MWC AB covers expense forecasts for programs not easily captured by other MWCs. This includes activities such as service contracts with third parties, asset data and risk model improvements, costs related to PG&E's Applied Technology Services (ATS) workstream, and regulatory and quality assurance efforts. PG&E's forecast for MWC AB and Cal Advocates' recommended reductions are summarized below.

²⁴⁵⁴ PG&E-17, p. 22-2, Table 22-1, line 5.

²⁴⁵⁵ PG&E-64, p. 3-2, Table 3A-1, lines 89-92.

²⁴⁵⁶ PG&E-17, p. 22-9, Table 22-5, line 3.

²⁴⁵⁷ PG&E-67, WP 3, lines "[Exhibit 4, Chapter] 22," MWCs 05 and 21.

**TABLE 4-52:
MISCELLANEOUS EXPENSE – PG&E’S EXPENSE FORECAST AND
PARTIES RECOMMENDED REDUCTIONS (\$000s)^(a)**

Party	2020 Rec.	2021	2022	2023
PG&E	\$47,137	\$6,365	\$9,155	\$49,510
Cal Advocates				\$(26,342)
(a) PG&E-17, p. 22-2, Table 22-1, line 1; p. 22-9, Table 22-4, line 1.				

Cal Advocates incorrectly claims that PG&E’s 2023 forecast for MWC AB is based on 2020 recorded costs.²⁴⁵⁸ Cal Advocates argues that PG&E’s 2020 recorded costs were higher than in other recent years and that PG&E has not shown that those higher costs will persist.²⁴⁵⁹ Based on this logic, Cal Advocates recommends a forecast based on a five-year average of PG&E’s 2016-2020 recorded adjusted expenses.²⁴⁶⁰

The Commission should not adopt Cal Advocates’ recommendation. PG&E’s 2023 forecast is based on bottoms-up forecasts for the various activities that make up MWC AB in this chapter. While the amount of the 2023 forecast as a whole is similar to the 2020 recorded amount, the proportion of spending on each of the component activities of MWC AB is quite different.²⁴⁶¹ A five-year average of recorded costs (2016-2020) is not appropriate for forecasting PG&E’s 2023 spending needs for MWC AB. Many of the support programs in MWC AB have evolved significantly since 2019 so that costs from 2016-2019 are not representative of 2020 recorded costs, or 2021 through 2023 forecast costs. In its rebuttal testimony, PG&E provided multiple examples of critical regulatory compliance and quality assurance functions that did not exist and/or have greatly expanded since 2019, along with the justification for the forecast increases.²⁴⁶² Basing PG&E’s 2023 funding for MWC AB on a 2016-2020 recorded cost average would severely limit PG&E’s ability to pursue these critical

²⁴⁵⁸ CALPA-04, p. 40, line 10.

²⁴⁵⁹ CALPA-04, p. 40, line 22 to p. 41, line 22.

²⁴⁶⁰ CALPA-04, p. 40, lines 14-18.

²⁴⁶¹ PG&E-17, p. 22-5, lines 3-10.

²⁴⁶² PG&E-17, p. 22-5, line 14 to p. 22-7, line 4.

activities. Tellingly, other than recommending the use of a five-year average, Cal Advocates made no criticisms of the work PG&E has forecast for the MWC AB programs in this chapter. Cal Advocates' recommended reductions are not supported and should not be adopted.

4.23 Community Rebuild Program

In the 2018 Camp Fire, approximately 199 miles of electric distribution lines and 34 miles of gas pipeline were destroyed. In May 2019, PG&E announced plans to underground all electric distribution assets in the Town of Paradise and adjacent parts of Butte County (also known as the underground footprint) to support safety and city planning efforts.²⁴⁶³ In regard to safety issues, many distribution poles fell into the streets and blocked access to egress routes during the fire.²⁴⁶⁴ The undergrounding of assets will help reduce wildfire risks from power lines in the area, which lies mostly in Tier 2 and 3 HFTD areas, and help ensure access to safe egress routes if there is another wildfire (regardless of source of ignition).²⁴⁶⁵ Government leaders and PG&E's customers in Paradise and Butte County have expressed the strong desire for underground utilities in their community to improve the safety egress paths and improve their town design.²⁴⁶⁶

During the rebuild efforts, the Paradise City Council is enforcing a "dig-once" ordinance.²⁴⁶⁷ To fulfill this obligation, PG&E is coordinating construction closely with Paradise to complete construction before the town repaves its primary town arteries.²⁴⁶⁸ PG&E also is taking advantage of the unique opportunity to underground replacement gas and electric

²⁴⁶³ PG&E-04, p. 23-11, lines 15-19.

²⁴⁶⁴ PG&E-04, p. 23-11, lines 20-21.

²⁴⁶⁵ PG&E-04, p. 23-11, lines 21-26.

²⁴⁶⁶ PG&E-04, p. 23-12, lines 7-10.

²⁴⁶⁷ PG&E-04, p. 23-12, line 10-12.

²⁴⁶⁸ PG&E-04, p. 23-12, lines 12-13.

facilities in a joint trench.²⁴⁶⁹ Performing joint trench work helps reduce underground construction costs over the entire program for both the gas and electric businesses.²⁴⁷⁰

Finally, PG&E's undergrounding will provide PSPS impact improvements for customers residing in the Paradise and Butte County areas.²⁴⁷¹ In 2020, these areas experienced five PSPS events spanning a total of 13 days.²⁴⁷² As the Community Rebuild project is executed over the next several years, it will enable undergrounded areas of Paradise to remain energized during PSPS events.²⁴⁷³ PG&E's project scoping for the Community Rebuild is prioritizing PSPS mitigation while working with the community to align with rebuild plans.²⁴⁷⁴ The Community Rebuild is managed centrally under a core team that oversees many LOBs within PG&E to complete the scope of work (electric, gas, sourcing, etc.).²⁴⁷⁵ The team also regularly communicates with Federal Emergency Management Agency and the local county and cities to coordinate construction locations and timelines.²⁴⁷⁶

4.23.1 PG&E's Expense And Capital Forecast

PG&E's TY 2023 expense forecast presented in rebuttal testimony is \$13.781 million.²⁴⁷⁷ PG&E's TY 2023 forecast in the JCE, including the September escalation adjustment, is \$15.548 million.²⁴⁷⁸

²⁴⁶⁹ PG&E-04, p. 23-11, line 33 to p. 23-12, line 2.

²⁴⁷⁰ PG&E-04, p. 23-12, lines 2-4.

²⁴⁷¹ PG&E-04, p. 23-12, lines 16-18.

²⁴⁷² PG&E-04, p. 23-12, lines 14-16.

²⁴⁷³ PG&E-04, p. 23-12, lines 16-18.

²⁴⁷⁴ PG&E-04, p. 23-12, lines 19-20.

²⁴⁷⁵ PG&E-04, p. 23-12, lines 21-23.

²⁴⁷⁶ PG&E-04, p. 23-12, lines 23-26.

²⁴⁷⁷ PG&E-17, p. 2-4, Table 2-1, line 23.

²⁴⁷⁸ PG&E-64, p. 3-2, Table 3A-1, line 93.

PG&E capital expenditures forecast presented in rebuttal testimony is \$87.513 million in 2021, \$124.132 million in 2022, \$116.590 million in 2023, \$96.096 million in 2024, \$64.367 million in 2025 and \$16.940 million in 2026.²⁴⁷⁹ PG&E’s capital expenditures forecast, including the September escalation adjustment, is \$90.222 million in 2021, \$135.315 million in 2022, \$131.690 million in 2023, \$112.305 million in 2024, \$74.431 million in 2025, and \$19.409 million in 2026.²⁴⁸⁰ ²⁴⁸¹

4.23.2 Summary Of Intervenors’ Recommendations

Cal Advocates proposes to remove PG&E’s entire Community Rebuild Program capital forecast from the GRC and recommends that recovery of these program costs should instead occur through the Catastrophic Events Memorandum Account (CEMA) application process.²⁴⁸² Cal Advocates also does not agree with PG&E’s inclusion of 2018-2022 recorded and forecast 2023-2026 capital costs associated with the Community Rebuild Program in the 2023 GRC Results of Operations Model.²⁴⁸³

TURN also recommends that the Commission deny rate recovery of any costs associated with the program.²⁴⁸⁴ TURN asserts that in order for PG&E to be permitted rate recovery of its Community Rebuild costs it must first establish that it acted reasonably prior to the fire, but made no such showing in this GRC.²⁴⁸⁵ TURN also suggests that all costs related to the

²⁴⁷⁹ PG&E-17, p. 2-5, Table 2-2, line 21 (2021); p. 2-6, Table 2-3, line 21 (2022); and p. 2-7, Table 2-4, line 21 (2023).

²⁴⁸⁰ PG&E-67, WP 3, line "[Exhibit 4, Chapter] 23," MWC 95.

²⁴⁸¹ Forecast amounts in Section 4.23.1 refer to Electric Distribution. There are additional Community Rebuild forecast costs in Section 3 (Gas Operations) and Section 6 (Customer and Communication).

²⁴⁸² CALPA-05, p. 46, line 26 to p. 47, line 5.

²⁴⁸³ CALPA-05, p. 51, lines 15-17.

²⁴⁸⁴ TURN-13, p. 1, lines 23-24.

²⁴⁸⁵ TURN-13, p. 2, lines 3-5.

Community Rebuild Program should be recorded as CEMA costs, subject to an after-the-fact reasonableness review by the Commission.²⁴⁸⁶ As explained in more detail below, the Commission should deny Cal Advocates’ and TURN’s arguments.

4.23.3 Community Rebuild Costs Forecast In The GRC Should Not Be Subject To CEMA

PG&E’s forecasts for the Community Rebuild Program from 2023-2026 should not be subject to CEMA cost recovery because they relate to activities beyond the restoration of service and repair of damaged facilities caused by the 2018 Camp Fire. Public Utilities Code Section 454.9 provides:

The commission shall authorize public utilities to establish catastrophic event memorandum accounts and to record in those accounts the costs of the following: (1) Restoring utility services to customers. (2) Repairing, replacing, or restoring damaged utility facilities. (3) Complying with governmental agency orders in connection with events declared disasters by competent state or federal authorities.

PG&E’s CEMA tariff states that “[t]he purpose of the CEMA is to recover the costs associated with the restoration of service and PG&E facilities affected by a catastrophic event declared a disaster or state of emergency by competent federal or state authorities.”²⁴⁸⁷ PG&E’s CEMA costs for the 2018 Camp Fire (still unrecovered) related to its initial restoration and repair efforts following the fire. These costs, recorded 2018-2022, included restoring overhead electrical power lines following the fire and connecting service to customers who were able to accept service immediately after the fire. These like-for-like restore/repair activities are what is traditionally recorded for recovery in CEMA.

Here, PG&E’s Community Rebuild activities forecast in the GRC from 2023-2026 are different than traditional like-for-like repair/restore activities under CEMA. Community Rebuild work mostly involves moving the services underground in order to mitigate wildfire risks, as

²⁴⁸⁶ TURN-13, p. 4, lines 3-7.

²⁴⁸⁷ Electric Preliminary Statement, Part G (Sept. 3, 2022), Section 1 (Purpose).

opposed to the CEMA work of restoring the overhead lines that had been destroyed, with PG&E restoring service to anyone that could take service at that time. PG&E's opening testimony explained that "[t]he scope of [Community Rebuild] excludes costs for [CEMA] emergency response activities PG&E incurred immediately following the Camp Fire, and covers the next phase of work to rebuild the distribution assets to meet the long-term needs of the community"²⁴⁸⁸ Put another way, the sequence of PG&E's activities can be described as: (1) CEMA work involving the temporary like-for-like installation/repair of overhead electric facilities to restore service following the 2018 Camp Fire;²⁴⁸⁹ followed by (2) Community Rebuild activities to underground overhead electric lines in the Town of Paradise and surrounding communities for wildfire mitigation and other safety purposes.²⁴⁹⁰ The first sequence of activities and costs (the like-for-like restoration work) are subject to CEMA cost recovery.²⁴⁹¹ The second sequence of activities and costs forecast from 2023-2026 in the GRC (PG&E's Community Rebuild undergrounding work) should be deemed to be recoverable in the GRC on a forecast basis.

Ignoring the difference between CEMA overhead-facilities restoration work and Community Rebuild undergrounding work, Cal Advocates and TURN appear to assume that the undergrounding work should constitute CEMA work merely because the work is taking place in Paradise. But this should not be the case. If that were true, then all Paradise-located work would conceivably be CEMA work in perpetuity. At some point in time, when PG&E performs work in Paradise, the work should no longer be recorded as CEMA work. Once the lines have been restored under CEMA activities, all subsequent activities pertaining to those lines (whether

²⁴⁸⁸ PG&E-04, p. 23-1, lines 18-21.

²⁴⁸⁹ PG&E-04, p. 23-1, lines 18-19.

²⁴⁹⁰ PG&E-04, p. 23-1, lines 20-22; p. 23-11, lines 20-26.

²⁴⁹¹ Some restoration work will continue. For example, when PG&E restores service to a customer who has returned to rebuild their property, the costs associated with restoring those costs may be CEMA costs.

PG&E hardens, undergrounds, or performs some other wildfire mitigation activity on them) should not be construed as a CEMA activity. In this sense, the Community Rebuild program, which is part of PG&E's 10,000 mile undergrounding program, should be viewed as a system-improvement project in the Town of Paradise, performed after CEMA activities had been completed.

The long-term timeline of PG&E's Community Rebuild work supports ratemaking through the GRC. PG&E's Community Rebuild undergrounding efforts will extend well beyond any typical CEMA work completed within the first few years after the event. Moreover, the future costs for the Community Rebuild program²⁴⁹² can be reasonably estimated, making them appropriate for recovery via forecast ratemaking.²⁴⁹³ The Commission's approval of a utility's cost recovery can take several forms including:

. . . adopting forecast costs in general rate cases; adopting a balancing account to allow recovery of actual reasonable costs that cannot be accurately forecast; or in the case of catastrophic events, when we cannot predict when, or the nature of, an event which may happen, establishing a trigger mechanism and a process to recover reasonable costs.²⁴⁹⁴

Here, 2023-2026 costs can be accurately forecast and are not CEMA costs for the reasons discussed above. Plus, the fundamental reason for utilizing CEMA – the inability of being able to accurately forecast costs in a GRC – does not exist here. Therefore, cost recovery in the GRC is an appropriate cost recovery mechanism.

TURN cites an inapposite standard in suggesting that PG&E must demonstrate the reasonableness of its actions prior to the 2018 Camp Fire in order to obtain cost recovery of its Community Rebuild costs.²⁴⁹⁵ TURN is alluding to a discussion in D.20-05-019, which was

2492 As explained in PG&E-04, p. 23-10, lines 7-11, the Community Rebuild Program is forecast to be complete by the end of 2025. Continuation of the installation of residential services requested by customers, which at this time is expected to continue beyond 2026.

2493 D.07-07-041, pp. 2-3.

2494 D.07-07-041, p. 6.

2495 TURN-13, p. 5, line 12 to p. 6, line 6.

also subsequently restated as a prerequisite for CEMA cost recovery in D.21-08-024 (SCE CEMA Decision): “as part of the reasonableness” of CEMA costs associated with utility-caused fires, the Commission “must . . . consider whether [the utility] acted prudently in maintaining its equipment.”²⁴⁹⁶ This standard pertains to CEMA cost recovery, not PG&E’s 2023-2026 forecast for Community Rebuild undergrounding work, which as discussed above, extends well beyond traditional CEMA restoration work. Thus, under this CEMA-review standard, PG&E would be required to demonstrate the reasonableness of its pre-Camp Fire actions in order to obtain CEMA cost recovery (i.e., recovery of costs relating to PG&E’s restoration of overhead lines). But this standard should not be construed to prohibit recovery of non-CEMA costs (i.e., the Community Rebuild undergrounding work forecast for 2023-2026).

4.23.4 PG&E Proposed Treatment Of Community Rebuild Costs Is Appropriate

In regard to PG&E’s results of operation model, PG&E has proposed to include in its 2023-2026 capital revenue requirements, the recorded and forecast capital costs associated with the Community Rebuild program.²⁴⁹⁷ As more fully discussed in Section 10 of this brief, PG&E is not precluded from including these capital costs in its rate base for purposes of computing its test year and post test year revenue requirements in a GRC.

In addition, PG&E has identified all CEMA recorded costs subject to disallowance ordered in D.20-05-019 for activities associated with rebuilding PG&E infrastructure destroyed by the 2018 Camp fire.²⁴⁹⁸ These CEMA-related disallowed amounts are not included in PG&E’s forecast or requested 2023 GRC RRQ.²⁴⁹⁹

²⁴⁹⁶ D.21-08-024, p. 26.

²⁴⁹⁷ PG&E-23-E, p. 15-3, lines 9-10.

²⁴⁹⁸ D.20-05-019, Appendix A, p. 3.

²⁴⁹⁹ PG&E-14, p. 3-AtchA-1, lines 6-9 (provides the supporting accounting showing the costs PG&E has absorbed to comply with the penalty in D.20-05-019).

4.24 Electric Distribution Ratemaking

4.24.1 Wildfire Mitigation Balancing Account (WMBA)

PG&E proposes to continue using the two-way WMBA to record wildfire mitigation related activities, including activities described in this application and activities in PG&E's 2022 WMP.²⁵⁰⁰ PG&E further proposes that the WMBA reasonableness review threshold for total spending and recorded average per mile for the various types of unit costs be raised from 115 percent to 125 percent.²⁵⁰¹ A two-way balancing account is the appropriate tool for recording costs for wildfire mitigations given the increasing wildfire risk and the ongoing impacts of climate change because it allows PG&E to adjust its comprehensive wildfire mitigation strategy as needed to keep our customers and communities safe. Raising the reasonable review threshold to 125 percent addresses the uncertainty PG&E faces in forecasting wildfire mitigation work due to the evolving wildfire risks and allows more flexibility to invest in effective mitigations, while still providing clarity on the regulatory review process for any costs over the forecasted amounts.²⁵⁰²

Cal Advocates supports continuing the two-way WMBA but opposes PG&E's request to raise the reasonableness review threshold for its WMBA from 115 to 125 percent, arguing there is too much uncertainty in PG&E's WMBA spending to increase the reasonableness review threshold.²⁵⁰³

TURN makes three recommendations: (1) the Commission should deny PG&E's request, and instead revise the WMBA to make it a one-way balancing account based on the adopted forecasts for wildfire mitigation programs; (2) on a forward-looking basis, if the Commission believes that these wildfire mitigation activities warrant providing PG&E with an opportunity to

²⁵⁰⁰ PG&E-04, p. 4-22, line 23 to p. 4-23, line 7.

²⁵⁰¹ PG&E-04, p. 4-24, lines 4-7.

²⁵⁰² PG&E-17, p. 4-7, lines 20-30.

²⁵⁰³ CALPA-04, p. 9, lines 8-13.

recover above-authorized spending on these programs, it should also create a companion Wildfire Mitigation Memorandum Account (WMMA) as the mechanism for recording above authorized spending, subject to later review in a reasonableness review application; and (3) the Commission should also deny PG&E's request for rate recovery of up to an additional 25 percent above the amounts authorized through a Tier 2 advice letter.²⁵⁰⁴ TURN notes that alternatively the Commission could adopt a treatment of above-authorized spending similar to that adopted for PG&E's AMI program, with 90 percent of up to 6 percent of the authorized amount deemed reasonable and recovered in rates without any after-the-fact reasonableness review. The remaining 10 percent would be absorbed by PG&E's shareholders.²⁵⁰⁵

The Commission should not adopt Cal Advocates' recommendation to keep the WMBA reasonableness threshold at 115 percent instead of raising it to 125 percent as PG&E proposes. The uncertainty PG&E faces in forecasting wildfire mitigation work is atypical of standard utility cost forecasting due to rapidly evolving climate-caused wildfire risks. Increasing the threshold will allow investments in cost-effective mitigations based on the most current information and analyses. PG&E also needs to be able to quickly respond to new legislative and regulatory directives.²⁵⁰⁶

The Commission also should not adopt TURN's recommendation to revise the WMBA and make it a one-way balancing account based on the adopted forecasts for wildfire mitigation. Wildfire risks are rapidly changing and increasing. In 2020 and 2021, California had its 5th and 2nd driest water years, respectively, in the last century and experienced unprecedented increases in the wildfire risk as a result of the ongoing impacts of climate change.²⁵⁰⁷ These increased wildfire risks drive continued uncertainty and variability associated with wildfire risk mitigation

²⁵⁰⁴ TURN-13, p. 23, line 10 to p. 24, line 2.

²⁵⁰⁵ TURN-13, p. 24, lines 7-10.

²⁵⁰⁶ PG&E-17, p. 4-6, lines 17-24.

²⁵⁰⁷ PG&E's 2022 Wildfire Mitigation Plan, OEIS Docket #2022-WMP (Feb. 25, 2022), p. 2.

activities and their associated costs. For example, the exact scope of PG&E's System Hardening Program will continue to evolve as PG&E performs detailed planning and engineering; the scope is also subject to the input of OEIS and other stakeholders who review PG&E's annual Wildfire Mitigation Plans (WMPs). For these reasons, there is some uncertainty regarding the scope of system hardening activities, including, for example, the exact number of miles of overhead system hardening versus undergrounding PG&E will complete each year. PG&E may make similar adjustments to other components of the CWSP, based on further planning and engineering, changing environmental conditions, new tools and technologies, and PG&E's understanding of evolving wildfire risks. Consequently, there is uncertainty regarding the wildfire mitigation costs PG&E ultimately will incur versus what is forecast in this GRC.²⁵⁰⁸

In its rebuttal testimony, PG&E provided examples of additional situations where a two-way balancing account provides needed flexibility, including where PG&E wants to evaluate and introduce new risk mitigation strategies without knowing what the ultimate scope of the investment will be (as in the case of the EPSS program)²⁵⁰⁹ or where the unpredictability of weather as well as the length of the wildfire season can lead to widely varying scope and costs for certain of PG&E's risk mitigation efforts (as is the case for PSPS).²⁵¹⁰

Due to the uncertainty described above, a two-way balancing account is an appropriate ratemaking mechanism. A one-way balancing account effectively imposes a cap on spending that restricts PG&E's ability to reasonably adjust its plans as necessary to respond appropriately to wildfire risks, including adjusting the mix of overhead system hardening and undergrounding.

The two-way WMBA has adequate protections for customers: customers pay only for actual work performed and if PG&E's forecast is higher than actual costs, the difference is returned to customers. In addition, the Commission and intervenors have the opportunity to

²⁵⁰⁸ PG&E-17, p. 4-4, lines 7-25.

²⁵⁰⁹ PG&E-17, p. 4-5, lines 6-29.

²⁵¹⁰ PG&E-17, p. 4-5, lines 22-25.

review PG&E's wildfire risk mitigation forecast for the WMBA through the GRC and PG&E's actual costs above its forecast through a combination of the Tier 2 advice letter process (for costs exceeding the WMBA forecast up to the reasonableness threshold proposed by PG&E) and reasonableness review (for costs incurred above the reasonableness threshold). Further, the Commission continues to have insight into PG&E activities and spending through the annual WMP submissions and the annual Spending Accountability Reports (SAR).²⁵¹¹

TURN's proposal to accompany its recommended one-way balancing account with a companion memorandum account as a mechanism for recording above-authorized spending, subject to later reasonableness review, is unnecessary. For the reasons explained above, a one-way WMBA is inappropriate given the variability PG&E's wildfire risk mitigation efforts. PG&E does not support a companion memorandum account given the administrative burden required to track and report costs in multiple accounts. The Commission and intervenors already have the ability to review PG&E's wildfire mitigation forecast and incurred cost through the Tier 2 advice letter and reasonableness review process described above.

The Commission should also reject TURN's proposal to adopt a treatment of above-authorized spending on wildfire risk mitigation similar to that adopted for PG&E's AMI program, with 90 percent of up to 6 percent of the authorized amount deemed reasonable and recovered in rates without any after-the-fact reasonableness review and the remaining 10 percent would be absorbed by PG&E's shareholders.²⁵¹² TURN's proposal would result in an automatic disallowance of costs that PG&E should have the opportunity to recover. PG&E should be afforded the opportunity to participate in a reasonableness review for costs above a certain threshold and given an opportunity to recover all its reasonably incurred costs.

²⁵¹¹ PG&E-17, p. 4-6, line 28 to p. 4-7, line 16.

²⁵¹² TURN-13, p. 24, lines 7-10.

4.24.2 Vegetation Management Balancing Account (VMBA)

In addition to continuing the WMBA, PG&E also proposes continuing the two-way VMBA through the 2023 GRC period. PG&E requests that the Commission increase the threshold for recorded amounts that can be recovered in the VMBA through a Tier 2 Advice Letter from 120 percent of adopted values to 125 percent of adopted values due to continuing uncertainties about VM costs due to external factors.²⁵¹³

Cal Advocates does not oppose PG&E's VMBA proposal and states that "PG&E's request to slightly increase the VMBA threshold is reasonable given the uncertainty in its Vegetation Management Program forecasts."²⁵¹⁴

TURN makes three recommendations related to PG&E's proposal: (1) the Commission revise the VMBA to return it to being a one-way balancing account;²⁵¹⁵ (2) if the Commission believes PG&E should have an opportunity to recover above-authorized spending on these programs, it should also create a companion Vegetation Management Memorandum Account (VMMA) as the mechanism for recording above-authorized spending, subject to later review in a reasonableness review application;²⁵¹⁶ and (3) the Commission could adopt a treatment of above-authorized spending similar to that adopted for PG&E's AMI program, with 90 percent of up to 6 percent of the authorized amount deemed reasonable and recovered in rates without any after-the-fact reasonableness review. The remaining 10 percent would be absorbed by PG&E's shareholders.²⁵¹⁷

The Commission should not adopt TURN's recommendations. TURN argues that PG&E should be able to forecast VM costs at a sufficient level of accuracy and confidence that the

²⁵¹³ PG&E-04, p. 9-67, lines 11-13.

²⁵¹⁴ CALPA-04, p. 22, lines 12-15.

²⁵¹⁵ TURN-13, p. 22, lines 4-6.

²⁵¹⁶ TURN-13, p. 22, lines 8-12.

²⁵¹⁷ TURN-13, p. 22, line 13 to p. 23, line 2.

protection of a two-way balancing account is no longer needed.²⁵¹⁸ But the two-way VMBA continues to be appropriate for VM programs because it addresses uncertainties and risks to the current program scope and forecast such as on-going and/or unforeseen changes to regulations, external commitments, customer input, weather, and other environmental/climate impacts that can adversely impact forecasts.

California continues to suffer through drought conditions that can have significant impacts on VM work. As noted above, California recently had its 5th and 2nd driest water years, respectively, in the last century and continues to experience the ongoing impacts of climate change. Addressing dead, dying and sick trees as required in the Tree Mortality Program is driven by climate conditions, making it difficult to accurately forecast the amount of work required each year. The scope of the Wood Management Program and the number of hazard trees that will need to be mitigated is also uncertain.²⁵¹⁹ PG&E's rebuttal testimony describes several ways in which its 2020 VBMA work ended up exceeding its forecast due to unforeseen, variable, and/or difficult to forecast factors.²⁵²⁰ This demonstrates that the scope and cost of vegetation management work is unpredictable and that two-way balancing account treatment is reasonable. The existing two-way VMBA protects customers as it requires PG&E to return any unspent funds at the end of the GRC period.

TURN's proposals to (1) accompany its proposed one-way VMBA with a companion memorandum account as a mechanism for recording above authorized spending, subject to later reasonableness review, or (2) make PG&E partially financially responsible for above-authorized costs in the VMBA through a mechanism similar to the one used for PG&E's AMI program, track similar proposals TURN made for the WMBA, and should be similarly rejected for the reasons discussed in Section 4.24.1 in connection with the WMBA proposals.

²⁵¹⁸ TURN-13, p. 22, lines 6-8.

²⁵¹⁹ PG&E-17, p. 9-12, lines 2-16.

²⁵²⁰ PG&E-17, p. 9-13, line 14 to p. 9-14, line 25.

4.24.3 Additional Balancing Accounts

PG&E discusses other contested Electric Distribution balancing accounts and memorandum accounts in the following sections of this brief:

- Catastrophic Event Straight-Time Labor Balancing Account (CESTBLA) – Section 4.6.3

PG&E lists the Electric Distribution uncontested balancing accounts and memorandum accounts in Appendix B. One account listed in Appendix B is also discussed in this brief:

- Rule 20 Balancing Account (RBA) - This accounting mechanism is not disputed but parties contest PG&E's forecast for the RBA as discussed in Section 4.19.

5. ENERGY SUPPLY (EXHIBIT PG&E-05)

PG&E's Energy Supply (Energy Supply or ES) activities are performed by the following organizations: Diablo Canyon Power Plant or DCPP, Power Generation, and Energy Policy and Procurement (EPP). PG&E delivers energy to approximately 5.5 million electric and 4.5 million natural gas households and businesses 24 hours a day. Working together, these organizations provide a safe, reliable, clean and affordable supply of energy to meet our customers' needs.

DCPP, Power Generation and EPP serve customers by safely and efficiently operating Utility-Owned Generation (UOG) resources, administering PG&E's electric and gas supply portfolio, and implementing comprehensive long-term energy resource strategies and plans to meet PG&E's customers' needs. State and federal regulatory requirements and mandates continue to increase in the areas of safety, renewable and clean energy, and other operational requirements impacting ES activities. PG&E's forecasts were prepared to meet these new requirements.

5.1 Forecast

PG&E's forecast of expense and capital expenditures for ES includes:

- The cost of safely operating and maintaining PG&E's generating facilities;
- The administrative costs of managing PG&E's ES portfolio;
- The costs associated with re-licensing PG&E's hydro facilities and complying with such licenses;
- Decommissioning costs of PG&E's hydro, natural gas, and solar generation facilities; and
- The cost to acquire, upgrade and enhance information technology systems that support the ES departments.

To continue to meet customer needs, PG&E must invest in its generating facilities to keep them operating safely, efficiently and in full compliance with legal and regulatory requirements. PG&E will also need to invest in its employees to ensure they have the talent, skills and technology need to analyze, implement, transact, administer, and operate in evolving markets.

PG&E's original TY 2023 O&M expense forecast for Energy Supply is approximately \$591²⁵²¹ million. PG&E's TY 2023 forecast presented in the JCE (Exhibit (PG&E-64), which accounts for a change due to escalation factors (the September 2022 Update Testimony) is approximately \$633 million.²⁵²²

PG&E's original capital expenditures forecast for Energy Supply is approximately: \$270 million in 2021, \$264 million in 2022, \$401 million in 2023, \$377 million in 2024, \$328 million in 2025 and \$282 million in 2026.²⁵²³ PG&E's capital expenditures JCE forecast is \$295 million in 2021, \$310 million in 2022, \$463 million in 2023, \$426 million in 2024, \$361 million in 2025 and \$304 million in 2026.²⁵²⁴

PG&E's original forecasts are fully supported by PG&E's initial testimony and workpapers (Exhibit PG&E-05) and PG&E's rebuttal testimony and workpapers (Exhibit PG&E-18).

After hearings, TURN and PG&E worked to resolve disputed issues related to our Energy Supply forecasts. As a result of this collaborative effort, TURN and PG&E reached a Stipulation resolving all contested issues between the parties except for escalation, attrition and depreciation issues (Energy Supply Stipulation). The Energy Supply Stipulation is included as Appendix E to our Opening Brief. For purposes of determining final values for each of the categories, PG&E and TURN agree that the final escalation amounts adopted by the Commission should apply to amounts in the Energy Supply Stipulation.²⁵²⁵

²⁵²¹ PG&E-05, p. 1-4, lines 22-23.

²⁵²² PG&E-64, p. 3-3, Table 3A-1, Total Exhibit (PG&E-05).

²⁵²³ PG&E-05, p. 1-9, Table 1-2, line 10.

²⁵²⁴ PG&E-64, p. 3-15, Table 3B-3, Total Exhibit (PG&E-05) (2021); p. 3-11, Table 3B-2, Total Exhibit (PG&E-05) (2022); p. 3-7, Table 3B-1, Total Exhibit (PG&E-05) (2023). Forecasts for 2024-2026 are not included in the JCE but are provided here for reference.

²⁵²⁵ TURN and PG&E are not resolving issues related to the Update Testimony which addresses, among other issues, PG&E's updated escalation factors.

The stipulated TY 2023 O&M expense forecast for Energy Supply is approximately \$575.2 million and the stipulated capital expenditures forecast is \$396.4 million in 2023, \$376.1 million in 2024, \$309.1 million in 2025, and \$264.9 million in 2026. The Energy Supply Stipulation reflects a compromise of disputed litigation positions on a range of issues addressed by the parties and constitutes an integrated agreement that should be approved in its entirety and without modification. TURN and PG&E jointly request that the Commission approve the provisions of this Energy Supply Stipulation instead of any contrary positions articulated in prepared testimony on the resolved issues.

Table 5-1 shows the original forecasted 2023 O&M expenses by ES department and Table 5-2 shows the original 2021-2026 capital expenditures by ES department. Table 5-3 shows the stipulated adjusted forecast of 2023 O&M expenses for ES department and Table 5-4 shows the stipulated adjusted forecast of 2021-2026 capital expenditures by ES department.

TABLE 5-1
PG&E’S ORIGINAL 2023 ENERGY SUPPLY EXPENSE FORECAST BY DEPARTMENT
(MILLIONS OF NOMINAL DOLLARS)^(a)

Organizations	2023
Nuclear Operations (Diablo Canyon Power Plant – DCPD)	\$313.6
Hydro Operations	\$177.9
Natural Gas and Solar	\$52.3
Energy Policy and Procurement	\$43.8
Business Technology	\$2.8
Energy Supply Total	\$590.4
(a) PG&E-05, p. 1-5, Table 1-1 as adjusted by PG&E-18, p. 6-3, Table 6-1, line 5.	

TABLE 5-2
PG&E'S ORIGINAL ENERGY SUPPLY CAPITAL FORECAST BY DEPARTMENT
(MILLIONS OF NOMINAL DOLLARS)^(a)

Organizations	2020 Rec.	2021	2022	2023	2024	2025	2026
Nuclear Operations (Diablo Canyon Power Plant – DCPD)	\$49.6	\$22.0	\$13.0	\$11.0	\$6.0	\$1.0	\$--
Hydro Operations	\$197.9	\$223.0	\$227.9	\$366.3	\$348.1	\$303.9	\$261.4
Natural Gas and Solar	\$16.0	\$10.0	\$5.4	\$6.3	\$9.2	\$9.7	\$7.4
Energy Policy and Procurement	\$--	\$--	\$--	\$--	\$--	\$--	\$--
Business Technology	\$19.3	\$12.3	\$15.0	\$14.1	\$13.9	\$13.7	\$13.5
Energy Supply Total	\$282.8	\$267.3	\$261.3	\$397.7	\$377.2	\$328.3	\$282.3

(a) PG&E-05, p. 1-9, Table 1-2 as adjusted by PG&E-18, p. 5-4, Table 5-3, line 9.

TABLE 5-3
STIPULATED ENERGY SUPPLY EXPENSE FORECAST
(MILLIONS OF NOMINAL DOLLARS)^(a)

Party	2023
PG&E Original Forecast	\$590.4
TURN Recommended Reduction	\$(56.6)
Joint Recommended Reduction	\$(15.2)
Total Adjusted 2023 Expense Forecast	\$575.2

(a) PG&E-05, p. 1-5, Table 1-1 as adjusted by PG&E-18, p. 6-3, Table 6-1, line 5 and TURN-14, Tables 2, 5, and 7.

TABLE 5-4
STIPULATED ENERGY SUPPLY CAPITAL FORECAST
(MILLIONS OF NOMINAL DOLLARS)^(a)

Party	2020 Rec.	2021	2022	2023	2024	2025	2026
PG&E Original Forecast	\$282.8	\$267.3	\$261.3	\$397.7	\$377.2	\$328.3	\$282.3
TURN Recommended Reduction	\$(90.9)	\$(48.1)	\$(96.3)	\$(201.4)	\$(296.1)	\$(297.6)	\$(250.4)
Joint Recommended Reduction				\$(1.3)	\$(1.1)	\$(19.2)	\$(17.4)
Total Adjusted Forecast				\$396.4	\$376.1	\$309.1	\$264.9

(a) PG&E-05, p. 1-9, Table 1-2 as adjusted by PG&E-18, p. 5-4, Table 5-3, line 9 and TURN-14, Tables 1, 3, 4, and 6.

PG&E believes that the Energy Supply Stipulation is reasonable, fully supported by the record, and should be adopted by the Commission as a whole. If the Commission does not adopt the Energy Supply Stipulation in its entirety, PG&E's original expense and capital expenditure forecasts should be adopted based on the evidence provided in Exhibits PG&E-05 and PG&E-18 and PG&E's supporting workpapers.

5.2 Energy Supply Risk Management

The Generation Risk and Compliance team implements PG&E's enterprise risk management program for all generation facilities. The risks for generation assets are defined in the Corporate Risk Register. Generation manages one RAMP risk: Large Uncontrolled Water Release (Dam Safety), and three non-RAMP risks: Nuclear Generation Core Damaging Event; Nuclear Generation Extended Shutdown; and Power Generation Extended Shutdown. The Generation Risk and Compliance organization is responsible for the integrated risk and compliance functions performed by Nuclear Generation/Power Generation. Parties did not raise any issues related to Energy Supply Risk management.

5.3 Nuclear Operations Costs

Diablo Canyon is a 2,240 MW facility located 7.5 miles North of Avila Beach in San Luis Obispo County, California. The site consists of approximately 12,000 acres of PG&E-owned land and the assets related to two nuclear units, including a power block and related facilities.²⁵²⁶ PG&E requested approval of O&M expenses, capital expenditures, and expense and capital forecasts in the Nuclear Regulatory Commission Regulatory Balancing Account (NRCBA). The request is a reduction from existing funding levels and reflects the reasonable costs to safely and reliably operate Diablo Canyon until expiration of the current operating licenses in 2024 and 2025.²⁵²⁷

5.3.1 Nuclear Operations Expense

PG&E's original TY 2023 expense forecast for nuclear operations was \$313.648 million.²⁵²⁸ PG&E's TY 2023 JCE forecast is \$328.876 million.²⁵²⁹ The primary drivers of the changes in expense from 2020-2023 are: escalation, changes in support cost allocations,

²⁵²⁶ PG&E-05, p. 3-14, line 29 to p. 3-15, line 2.

²⁵²⁷ PG&E-05, p. 3-1, lines 6-12.

²⁵²⁸ PG&E-18, p. 3-3, Table 3-1, line 12.

²⁵²⁹ PG&E-64, p. 3-3, Table 3A-1, lines 94-104.

changes in outage work scope and duration, employee attrition, burden rate changes, security overtime and other cost changes.²⁵³⁰

The nuclear operations expense forecast includes work tracked in 11 MWCs. TURN recommended a reduction of \$21.540 million across nine different MWCs, disputing the head count assumptions in PG&E's labor forecasts.²⁵³¹ PG&E's forecasts in MWCs AK (Manage Environmental Operations) and EO (Provide Nuclear Support) are undisputed.²⁵³² See Appendix A. TURN was the only party to dispute PG&E's nuclear O&M expense forecast.

As part of the Energy Supply Stipulation, TURN and PG&E agreed to a total authorized expense of \$304.4 million. PG&E urges the Commission to find the nuclear expenses provision of the stipulation a reasonable compromise of positions that, in combination with other provisions in the overall stipulation, merits its adoption without modification. Table 5-5 shows the stipulated nuclear expense forecast.

TABLE 5-5
STIPULATED NUCLEAR OPERATIONS EXPENSE FORECAST
(THOUSANDS OF NOMINAL DOLLARS)^(a)

Party	2023
PG&E Original Forecast	\$313,648
TURN Recommended Reduction	\$(21.540)
Joint Recommended Reduction	\$(9,200)
Total 2023 Adjusted Forecast	\$304.448

We request that the Commission adopt the stipulated total 2023 adjusted expense forecast for nuclear operations agreed to by TURN and PG&E. The stipulated outcome is fully supported by evidence in the record.²⁵³³

²⁵³⁰ PG&E-05, p. 3-5, line 1 to p. 3-8, line 25.

²⁵³¹ TURN-14, p. 87, line 13 to p. 88, line 1.

²⁵³² PG&E-18, p. 3-1, lines 23-29.

²⁵³³ PG&E-05, p. 3-3 to p. 3-8, p. 3-33 to p. 3-46; PG&E-18, p. 3-9 to p. 3-24.

5.3.2 Nuclear Operations Capital

The capital expenditures forecast for Diablo Canyon are in MWCs 20 and 5 and totaled \$48.6 million in 2020.²⁵³⁴ For 2023-2026, PG&E's original forecast was \$11.0 million, \$6.0 million, \$1.0 million, and \$0.²⁵³⁵ This significant year-over-year decrease in capital expenditures is a result of PG&E's thorough re-examination of required expenditures in light of an expected shutdown in 2025.²⁵³⁶ This level of capital expenditures is necessary and appropriate to support safe and reliable operations.²⁵³⁷

TURN disputed the need for the DCPD Aging Management program, propose disallowance of the Unit 2 Polisher Computer workstation project, and recommended that 50 percent of the costs for two other capital projects be collected through Decommissioning Trust funds.²⁵³⁸ In total, TURN recommended a reduction of \$4.201 million in 2023, \$4.954 million in 2024, and \$0.998 million in 2025.²⁵³⁹

TURN agreed to PG&E's forecast of capital expenditures in exchange for PG&E's agreement that only the Commission-authorized forecasts in this GRC will be recorded and recovered through the Diablo Canyon Retirement Balancing Account (DCRBA). This is a reasonable compromise because it addresses TURN's concern that costs recorded to the DCRBA are not subject to reasonableness review but also provides sufficient capital for the safe and reliable operation of DCPD through expiration of the current operating licenses.

Table 5-6 shows the stipulated nuclear operations capital expenditure forecasts.

²⁵³⁴ PG&E-05, p. 3-52, Table 3-21.

²⁵³⁵ PG&E-18, p. 3-5, Table 3-3, line 4.

²⁵³⁶ PG&E-05, p. 3-9, line 5 to p. 3-10, line 2.

²⁵³⁷ PG&E-05, p. 3-13, lines 27-31.

²⁵³⁸ TURN-14, p. 7, Table 3.

²⁵³⁹ PG&E-18, p. 3-4, Table 3-2, line 4.

TABLE 5-6
STIPULATED NUCLEAR OPERATIONS CAPITAL FORECAST
(THOUSANDS OF NOMINAL DOLLARS)^(a)

Party	2020 Rec.	2021	2022	2023	2024	2025	2026
PG&E Original Forecast	\$49,650	\$22,000	\$13,000	\$11,000	\$6,000	\$1,000	\$0
TURN Recommended Reduction	\$(14,854)	\$(3,317)	\$(4,182)	\$(4,201)	\$(4,954)	\$(998)	\$0
Joint Recommended Reduction	\$0	\$0	\$0	\$0	\$0	\$0	\$0
Total Adjusted Forecast	\$49,650	\$22,000	\$13,000	\$11,000	\$6,000	\$1,000	\$0

(a) PG&E-18, p. 3-4, Table 3-2, line 6 and PG&E-18, p. 3-30, Table 3-5, line 5 and TURN-14, p. 7, Table 3.

We request that the Commission adopt the stipulated total 2023 adjusted capital expenditure forecast for nuclear operations agreed to by TURN and PG&E in the Energy Supply Stipulation. The stipulated outcome is fully supported by record evidence.²⁵⁴⁰

5.3.3 Nuclear Ratemaking Proposals

PG&E included the following nuclear ratemaking proposals in this proceeding, all of which are undisputed:

- Continue to recover the net book value associated with DCPD through the DCRBA and to close the DCRBA at the end of plant life;
- Continue the two-way balancing account for expense costs related to implementation of NRC requirements, and close the NRCBA at the end of currently-licensed plant life;
- Modify the methodology for forecasting the proceeds from the Department of Energy litigation settlements by utilizing amounts explicitly attributable to Nuclear Operations, Humboldt Bay Power Plant, and DCPD decommissioning;²⁵⁴¹
- Update the project cancellation amounts consistent with the DCPD retirement decision;²⁵⁴² and
- Approve PG&E's updated calculation of the end-of-life inventory balance, proposed changes in the treatment of the salvage activity, and an increase in the amortization period for the materials surplus inventory. Charge any

²⁵⁴⁰ PG&E-05, p. 3-8 to p. 3-14; PG&E-18, p. 3-24 to p. 3-28.

²⁵⁴¹ PG&E-18, p. 8-2, lines 6-15.

²⁵⁴² PG&E-05, p. 3-3, lines 23-25 and PG&E-05, WP 3-99 to WP 3-100.

procurement department labor incurred after August 2025 incurred for purposes of inventory salvage and disposal to the DCRBA.²⁵⁴³

The Commission should approve PG&E's request to continue ratemaking previously found reasonable and undisputed in this proceeding.

5.4 Hydro Operations Costs

PG&E operates one of the largest investor-owned hydroelectric systems in the United States for the benefit of its electric customers, both bundled and unbundled, and the public. PG&E's customers - and the state as a whole - benefit from the continued safe and reliable operation of the hydro system because it provides high-value, low cost, dispatchable electricity products (energy, capacity and ancillary services) to meet their demands, and supports integration of intermittent renewable energy. In addition, PG&E's customers and the public benefit from this greenhouse gas emission free source of electricity and PG&E's associated land conservation, recreation and environmental commitments.²⁵⁴⁴ PG&E developed its expense and capital forecasts in this proceeding to ensure that customers receive the substantial benefits of PG&E's hydro facilities and that these facilities continue to be safely and reliably operated.

5.4.1 Hydro Expense

PG&E's hydro O&M expense forecast covers the direct operations and maintenance expenses for the 64 hydro powerhouses and support facilities, as well as the operational management and support services.²⁵⁴⁵ PG&E's original TY 2023 expense forecast for hydro operations was \$177.909 million.²⁵⁴⁶ PG&E's TY 2023 forecast presented in the JCE is \$197.394 million.²⁵⁴⁷ The primary drivers of the 2023 expense forecast increase over 2020 recorded expense are escalation, regulatory compliance, increase in costs to maintain hydro

²⁵⁴³ PG&E-05, p. 3-2, line 26 to p. 3-3, line 12.

²⁵⁴⁴ PG&E-05, p. 4-1, lines 10-18.

²⁵⁴⁵ PG&E-18, p. 4-8, lines 6-8.

²⁵⁴⁶ PG&E-18, p. 4-3, Table 4-1, line 18.

²⁵⁴⁷ PG&E-64, p. 3-3, Table 3A-1, lines 105-119.

infrastructure, decrease in costs to operate hydro assets and decrease in other hydro costs.²⁵⁴⁸

This includes work tracked in 16 MWCs.²⁵⁴⁹

TURN proposed a total reduction of approximately \$35.1 million to PG&E's 2023 O&M expense forecast based on the following proposals:

- Use a 4-year average (2016-2019) as the basis for the O&M expense forecast;
- Use a 10-year average (2010-2020) as the basis for headcount assumptions included in the O&M expense forecast;
- Set forecasts for Large Uncontrolled Water Release projects at the level PG&E presented in the 2020 RAMP Report;
- Remove the cost to comply with license conditions for projects with pending FERC relicensing applications; and
- Transfer of projects out of the HLBA that are not required by a FERC license.

Cal Advocates proposed a total reduction of \$3.5 million to PG&E's 2023 O&M forecast based on the following recommendations:

- Remove the cost of six additional hires to support ISO 55000 certification; and
- Remove the cost for the Recreation Point Campground project.

PG&E and TURN have agreed to reduce the TY 2023 hydro operations expense forecast by \$6.0 million, which includes \$4.7 million in 2023 for setting LUWR costs equal to the 2020 RAMP forecast and \$1.3 million in 2023 in response to TURN's and Cal Advocates' headcount reduction recommendations, for a total TY 2023 hydro operations forecast of \$171.9 million as indicated in Table 5-7 below.

TABLE 5-7
STIPULATED HYDRO OPERATIONS EXPENSE FORECAST
(THOUSANDS OF NOMINAL DOLLARS)^(a)

Party	2023
PG&E Original Forecast	\$177,909
TURN Recommended Reduction	\$(35,080)

²⁵⁴⁸ PG&E-05, p. 4-4, line 5 to p. 4-5, line 23.

²⁵⁴⁹ MWCs: AB, AK, AX, AY, BC, EP, ES, IG, KG, KH, KI, KJ, LX, OM, OS and ZC.

Party	2023
Joint Recommended Reduction	\$(6,000)
Total Adjusted Forecast	\$171,909
(a) PG&E-18, p. 4-3, Table 4-1, line 18.	

We request that the Commission adopt the stipulated total 2023 adjusted hydro expense forecast agreed to by TURN and PG&E. The agreed-upon reduction also exceeds the amount of reduction proposed by Cal Advocates. The stipulated outcome is fully supported by evidence in the record and should be approved.²⁵⁵⁰

5.4.1.1 Operational Support (MWC OS)

MWC OS includes labor and employee related costs to provide services and support that are unrelated to supervision and management. Examples include Business Finance and Sourcing personnel supporting the Power Generation line of business.²⁵⁵¹ PG&E's 2023 expense forecast for MWC OS is \$4.047 million.²⁵⁵² The forecast increase is primarily driven by escalation and filling vacancies in support organizations like Asset Management and Hydro Outage and Project Management.²⁵⁵³ Cal Advocates recommends a reduction of \$0.9 million based on elimination of the cost of six new hires it asserts were needed only for a limited assignment.²⁵⁵⁴

As part of the 2020 GRC Settlement, PG&E agreed with the Commission's then-existing Office of the Safety Advocate (OSA) to make a good faith effort to apply for and attain an ISO 55000 certification for its dams from an accredited organization by the end of 2022. PG&E also agreed to begin the gap analysis required to initiate an ISO 55000 certification for its other hydro

²⁵⁵⁰ PG&E-05, p. 4-3 to p. 4-5, p. 4-41 to p. 4-50; PG&E-18, p. 4-8 to p. 4-18, p. 4-22 to p. 4-26, p. 4-32 to p. 4-34.

²⁵⁵¹ PG&E-18, p. 4-12, lines 24-27.

²⁵⁵² PG&E-18, p. 4-3, Table 4-1, line 15.

²⁵⁵³ PG&E-18, p. 4-12, line 27 to 4-13, line 2.

²⁵⁵⁴ CALPA-08, p. 11, lines 22-25.

assets in 2023 or earlier.²⁵⁵⁵ To achieve certification, PG&E had to establish programmatic and process improvement changes to address major and minor non-conformances identified in the Lloyd's Register ISO 55000 analysis in 2020. PG&E hired the six employees Cal Advocates proposes to remove from the O&M expense forecast to perform the work required to achieve the certification requested by the Commission's OSA.²⁵⁵⁶ While PG&E was able to achieve certification in 2022 on its entire portfolio, including: dams, hydro powerhouses, civil infrastructure, fossil, solar, battery storage, physical data and data assets, the programs and processes established to support certification must be maintained.²⁵⁵⁷ The need for these employees did not roll off with achieving certification; they have continued responsibility for tracking maintenance notifications to support lifecycle management, staff the tool calibration program, facilitate management review and other new asset management processes and documentation.²⁵⁵⁸ Finally, these employees will support annual compliance audits.

Cal Advocates suggests that PG&E has not presented sufficient evidence to support the additional six positions.²⁵⁵⁹ In reality, PG&E provided extensive explanation supporting the need for these employees and the procedure for hiring them. Specifically, record evidence shows that each new hire request is presented to a workforce hiring committee and approved based on the merits of the role as it pertains to PG&E's operating success, including controlling risks. The committee questions the need for the role, alternative approaches to filling the role, such as absorbing the work within the existing workforce or hiring contractors if the role is temporary, and the cost component.²⁵⁶⁰ Upon review, the workforce hiring committee approved these six

²⁵⁵⁵ PG&E-18, p. 4-14, lines 19-22.

²⁵⁵⁶ PG&E-18, p. 4-13, lines 14-15.

²⁵⁵⁷ Id.

²⁵⁵⁸ PG&E-18, p. 4-13, line 25 to p. 4-14, line 15.

²⁵⁵⁹ CALPA-08, p. 11, lines 4-5.

²⁵⁶⁰ PG&E-18, AppA-33.

positions. PG&E has amply demonstrated these positions are necessary long term; the Commission should reject Cal Advocates' proposed reductions.

5.4.1.2 Balancing Account Process (MWC IG)

PG&E uses MWC IG to track expense costs in the Hydro Licensing Balancing Account (HLBA). Major projects in MWC IG for 2023 include the Crane Valley Recreation Settlement Agreement and FERC license condition projects like McCloud Pit and Drum Spaulding. PG&E's expense forecast for MWC IG is \$30.552 million.²⁵⁶¹ Cal Advocates recommends a reduction of \$2.6 million in costs for the Recreation Point Campground.²⁵⁶² TURN's proposed reduction of \$14.642 million was resolved as part of the compromises in the Energy Supply Settlement.²⁵⁶³

Cal Advocates claims PG&E has not provided sufficient support for its forecast and that deferring consideration of the project to PG&E's next GRC will allow the Forest Service to fund the project.²⁵⁶⁴ Its recommendations should be rejected.

The Recreation Point Campground Project is required by the Crane Valley Recreation Settlement Agreement between PG&E and the US Forest Service (executed October 28, 2002). It includes planning, design, installation, rehabilitation, and repair of several recreational facilities at Bass Lake.²⁵⁶⁵ Work on this project must begin in 2023 to support completion by 2025. PG&E has no indication that the US Forest Service will fund the project and PG&E is required to move forward with the recreational facility improvements. Accordingly, it is reasonable to include the forecast required to satisfy this license condition in the 2023 HLBA

²⁵⁶¹ PG&E-18, p. 4-3, Table 4-1, line 8.

²⁵⁶² PG&E-18, p. 4-3, Table 4-1, line 8.

²⁵⁶³ TURN-14, p. 13, Table 7, line 6b2 and 6b3, TURN-14, p. 31, Table 16.

²⁵⁶⁴ PG&E-18, p. 4-16, lines 27-29.

²⁵⁶⁵ The Settlement Agreement between PG&E and the US Forest Service became a requirement of the FERC license for the Crane Valley Project (FERC No. 1354) when the license was issued September 16, 2003.

expense forecast even though the project may not be completed until 2025. While it is not possible to know the specific scope and duration of the project, which will be dictated by the US Forest Service, PG&E is familiar enough with the work required for this type of recreational project to forecast the costs for work included in PG&E's \$2.6 million forecast – scoping/design, procurement, permitting and construction. PG&E's forecast assumes the first two years of the project will involve design and permitting, with construction in 2025.²⁵⁶⁶

In the 2020 GRC, the Commission approved a settlement allowing the costs of the Crane Valley Recreational Settlement Agreement to be recovered through the HLBA.²⁵⁶⁷ It is prudent to authorize recovery of the forecast for the Recreation Point Campground Project in this proceeding, especially given that recording these costs to the HLBA ensures that customers will pay only actual costs incurred.

5.4.2 Hydro Capital Expenditures

PG&E's original capital expenditures forecast was \$222.983 million in 2021, \$227.948 million in 2022, and \$366.287 million in 2023. PG&E's attrition year capital forecasts are \$348.143 million in 2024, \$303.893 million in 2025 and \$261.443 in 2026.²⁵⁶⁸ PG&E's capital expenditures forecast presented in the JCE is \$247.394 million in 2021, \$271.576 million in 2022, and \$425.854 million in 2023. PG&E's attrition year forecasts including the September 6, 2022 escalation adjustment are \$391.731 million in 2024, \$332.566 million in 2025 and \$279.771 in 2026.

The primary drivers of this forecast are costs to support FERC relicensing, new FERC license implementation work (MWC 3H), risk mitigations associated with the Large Uncontrolled Water Release (LUWR) risk, Fordyce Dam leakage reduction work (MWC 2L), and two projects related to employee safety, the James B. Black (JBB) Road Stabilization and

²⁵⁶⁶ PG&E-18, p. 4-17, lines 14-17.

²⁵⁶⁷ PG&E-18, p. 4-18, lines 3-7; D.20-12-005, pp. 135-136.

²⁵⁶⁸ PG&E-18, p. 4-37, Table 4-7, line 11.

Helms Crane Rail Capacity Uprate (MWC 2P).²⁵⁶⁹ PG&E's hydro capital work is tracked in 9 MWCs.²⁵⁷⁰

TURN recommended reductions to PG&E's capital expenditure forecasts of \$193.833 million in 2023, \$288.846 million in 2024, \$293.757 million in 2025, and \$245.955 million in 2026 based on the following proposals:²⁵⁷¹

- Remove capital forecast for Emergent Work (MWC 2N);
- Set capital forecasts for LUWR projects to forecasts presented in the 2020 RAMP (MWCs 2L, 2N and 3H);
- Remove capital forecasts for license condition projects with pending FERC licenses (3H);
- Remove forecasts for projects with operative dates after 2023 (MWC 11, 2L, 2M, 2N, 2P and 3H); and
- Remove forecasts after 2023 for projects with operative dates before 2024 (MWCs 2L, 2M, 2N and 3H).²⁵⁷²

In addition to its proposal to use 2021 recorded data, Cal Advocates recommends a total reduction of approximately \$53.5 million to PG&E's 2023 capital expenditures forecast based on the following proposals.²⁵⁷³

- Remove \$46.9 million for license condition projects at the Upper North Fork Feather River, Drum Spalding and McCloud Pit (MWC 3H); and
- Remove \$6.5 million for the James B. Black (JBB) Willow Creek Stabilization project (MWC 2P).

PG&E and TURN agreed to reduce the hydro operations capital expenditure forecast in the Energy Supply Stipulation as indicated in Table 5-8 below.

²⁵⁶⁹ PG&E-05, p. 4-7, line 9 to p. 4-8, line 6.

²⁵⁷⁰ MWCs: 5, 11, 12, 2L, 2M, 2N, 2P, 3H and 3Q. PG&E's forecasts in 5, 12 and 3Q are undisputed.

²⁵⁷¹ PG&E-18, p. 4-4, Table 4-2, line 11.

²⁵⁷² PG&E-18, p. 4-4, Table 4-2, line 11.

²⁵⁷³ PG&E-18, p. 4-4, Table 4-2, line 11.

TABLE 5-8
STIPULATED HYDRO OPERATIONS CAPITAL FORECAST
(THOUSANDS OF NOMINAL DOLLARS)^(a)

Party	2020 Rec.	2021	2022	2023	2024	2025	2026
PG&E Original Forecast	\$197,937	\$222,983	\$227,948	\$366,287	\$348,143	\$303,893	\$261,443
TURN Recommended Reduction	\$(79,713)	\$(41,550)	\$(82,084)	\$(193,833)	\$(288,846)	\$(293,757)	\$(245,955)
Joint Recommended Reduction	\$0	\$0	\$0	\$(1,078)	\$1,238	\$(16,381)	\$(12,942)
Total Adjusted Forecast	\$197,937	\$222,983	\$227,948	\$365,209	\$349,381	\$287,512	\$248,501

(a) PG&E-18, p. 4-4, Table 4-2, line 11 and PG&E-18, p. 4-37, Table 4-7, line 11 and TURN-14, p. 5, Table 1 and p. 12, Table 6.

As part of the Energy Supply Stipulation, TURN and PG&E agreed to the following hydro capital related changes:

- Set the 2023-2026 capital expenditure forecast for LUWR projects equal to the average between PG&E’s 2020 RAMP forecast and its GRC forecast, for a total 2023-26 reduction of \$29.163 million. This results in a total Hydro capital expenditure forecast of \$365.209 million, \$349.381 million, \$287.512 million, and \$248.501 million for 2023, 2024, 2025, and 2026, respectively.
- For Hydro License Balancing Account (HLBA) capital additions with forecasted operative dates after 12/1/2026, change project operative date to 1/15/2027. This results in 2026 capital additions decrease of \$306.65 million (\$319.6 million - \$12.95 million).
- For HLBA capital project, “Spillway Assessment Prgm Cap Mitigation,” change operative date from 12/15/21 to 1/15/24. This results in a 2023 capital addition decrease and a 2024 capital addition increase.

All of these changes will be to MWC 3H, the HLBA. TURN and Cal Advocates proposed reductions to PG&E’s hydro capital expenditures forecast because they claim costs recorded in the HLBA are uncertain, increasing in magnitude, and are continually being pushed out to later years.²⁵⁷⁴ The agreement reflected in the Energy Supply Stipulation addresses this concern while also ensuring that funding is available for PG&E to implement regulatorily required capital projects.

²⁵⁷⁴ TURN-14, p. 88, line 18 to p.110, line 20.

We request that the Commission adopt the stipulated total 2023 adjusted hydro capital expenditure forecast agreed to by TURN and PG&E. The stipulated outcome is fully supported by record evidence.²⁵⁷⁵

5.4.2.1 Cal Advocates Proposal To Use 2021 Recorded Data

Cal Advocates recommends use of 2021 recorded data for all hydro capital projects (MWC 2L-3Q) based on its assertion that 2021 recorded costs is “a true representation of PG&E’s actual spending.”²⁵⁷⁶ PG&E’s response to Cal Advocates inconsistent recommendations regarding the use of 2021 recorded data instead of PG&E’s 2021 forecast is presented in section 1.5 of this brief. As we discussed above, we believe that the parties should not be allowed to arbitrarily choose on a program-by-program basis, whether to true up for recorded costs based on whether the recorded costs are higher or lower than PG&E’s 2021 forecast. Allowing a true up only when costs are lower than the forecast as Cal Advocates suggest but not when they are higher than the 2021 forecast would be unfair and unduly prejudicial to PG&E.

5.4.2.2 Install/Replace Infrastructure (MWC 2P)

PG&E’s capital forecast for MWC 2P is \$26.574 million in 2023, \$14.553 million in 2024, \$12.954 million in 2025, and \$9.650 million in 2026.²⁵⁷⁷ Cal Advocates recommends a reduction of \$6.5 million in 2023 for the James B. Black Willow Creek Stabilization Project.²⁵⁷⁸

The scope of the JBB Willow Creek Road Stabilization project is to repair damage and remove debris in order to restore road access to the James B. Black siphon at the request of the

²⁵⁷⁵ PG&E-05, p. 4-5 to p. 4-8, p. 4-50 to p. 4-62, p. 4-72 to p. 4-74; PG&E-18, p. 4-18 to p. 4-38.

²⁵⁷⁶ CALPA-08, p. 16, lines 3-4.

²⁵⁷⁷ PG&E-18, p. 4-4, Table 4-2, line 8.

²⁵⁷⁸ CALPA-08, p. 20, line 6-8.

Forest Service.²⁵⁷⁹ Cal Advocates claims that PG&E has not adequately supported the project because it did not complete an alternatives analysis and recommends deferring consideration of this project to PG&E's next GRC to provide an opportunity to review the alternatives considered for the project.²⁵⁸⁰

Cal Advocates' proposal to defer consideration of this project to the 2027 GRC is unacceptable. Currently, PG&E does not have sufficient access to the JBB siphon, a segment of the water conveyance that carries water to the powerhouse. The project must be implemented in the near term because, without it, PG&E can only access the siphon on foot or by helicopter to perform inspection and maintenance work significantly affecting PG&E's ability to perform maintenance work. This could result in additional forced outage time to the powerhouse and emergent costs of repairing the road in an emergency situation, creating additional and unnecessary costs.²⁵⁸¹

Cal Advocates' objection to this safety and reliability related project, which needs to begin near term but won't be operable until after 2023, is unreasonable. The record in this proceeding amply supports Commission approval of this project without delay.

5.4.2.3 Forecasts For FERC Projects With Pending Licenses (MWC 3H)

Cal Advocates proposes a reduction to the capital forecasts for license condition projects for the Upper North Fork Feather River (UNFFR), McCloud Pit, and Drum Spaulding FERC Licenses. Each of these three FERC projects is expected to be operational in December 2026.²⁵⁸² Cal Advocates claims that since the operative dates for these three FERC license condition projects are December 2026, these projects will not affect the 2023 GRC revenue

²⁵⁷⁹ PG&E-18, p. 4-18, lines 10-11 and WP 4-164.

²⁵⁸⁰ PG&E-18, p. 4-18, lines 21-24.

²⁵⁸¹ PG&E-18, p. 4-18, line 25 to p. 4-19, line 31.

²⁵⁸² PG&E-18, p. 4-20, lines 1-5.

requirement so Cal Advocates recommends removal of these capital expenditure forecasts from this GRC.

Cal Advocates proposes to remove the capital forecasts for license conditions related to the UNFRR, Drum Spalding and McCloud Pit projects reduces the MWC 3H forecast by \$46.947 million in 2023.²⁵⁸³

PG&E included project forecasts for pending license conditions in this GRC consistent with the Commission's Rate Case Plan, which states that the GRC application presents detailed forecasts of the applicant's capital investment expenses and its operating and maintenance expenses for a designated test year as well as forecasts for subsequent post-test years or attrition years.²⁵⁸⁴ Additionally, PG&E must file a Risk Spending Accountability Report (RSAR) annually. The RSAR includes the authorized and actual spending for risk mitigation programs identified in the program RAMP and other programs related to safety, reliability or maintenance presented in the GRC application. MWC 3H is a program related to safety and the capital forecast for these license condition projects span 2021-2026. Accordingly, the capital forecasts must be included in the GRC forecast regardless of the operative date.²⁵⁸⁵

PG&E's capital forecast in MWC 3H includes a reasonable estimate of the cost to implement new license conditions. These costs are subject to refinement over time based on additional information available as the relicensing proceeding progresses but can be estimated based on PG&E's extensive experience with the state and federal agencies and the type of license conditions typically imposed on hydro facilities in California. Given the ability to forecast these costs subject to refinement and the requirement to present post-test year capital forecasts, the Commission should reject proposal from Cal Advocates and approve PG&E's

²⁵⁸³ CA-08, p. 15, Table 8-7.

²⁵⁸⁴ PG&E-18, p. 4-21, lines 15-21 and D.20-01-002, p. 8.

²⁵⁸⁵ PG&E-18, p. 4-21, line 24 to p. 4-22, line 3 and D.19-04-020, p. 64, OP 8.

forecast for MWC 3H, including the forecast for license condition projects for projects with pending licenses.

5.4.3 Potter Valley Transformer Project

In summer 2021, the transformer at the Potter Valley Project powerhouse failed. In early 2022, PG&E decided to replace the transformer. PG&E estimates that replacing the transformer will cost \$8.9 million and plans to recover this cost within the approved 2023 GRC forecast amount. PG&E did not forecast the cost of this project in the GRC because the timing of the decision to replace the transformer was after PG&E had finalized its forecast for this GRC.²⁵⁸⁶

While CalTrout does not make an affirmative recommendation in its testimony, PG&E expects CalTrout will take the position that it is unreasonable for PG&E to recover the cost to replace the transformer within the approved 2023 GRC forecast amount. CalTrout suggests that the surrender and decommissioning process for Potter Valley can be accomplished in 4-6 years and that average flows and power production are likely to fall further during the remaining years of Project operation.²⁵⁸⁷ CalTrout questions the economic viability of the project, suggesting that going forward with the project is not in the best interest of PG&E's customers.²⁵⁸⁸

The transformer should be replaced because PG&E is unable to return the powerhouse to service until a new transformer is installed. PG&E's economic analysis, which utilizes current forward price curves for energy pricing and historical generation data from the plant to determine economic viability, along with ancillary service and capacity value, demonstrates that it is beneficial to customers to bring the powerhouse back online to earn revenues during the FERC license surrender process. Based on 30-year historic average waterflows and an assumption that

²⁵⁸⁶ PG&E-18, p. 4-26, lines 8-14.

²⁵⁸⁷ CalTrout-1E, p. 3, lines 12-16 and p. 13, lines 5-6.

²⁵⁸⁸ PG&E-18, p. 4-26, lines 18-27.

decommissioning can begin in 10 years and will take 5 years, it is cost-effective to replace the transformer.²⁵⁸⁹

CalTrout has presented little support for its opinion that average flows and power production are likely to fall during the remaining years of operation.²⁵⁹⁰ Further, PG&E has found no example of a hydroelectric facility completing the license surrender process in 4 years. Even assuming a 4-year license surrender process, actual decommissioning work would not begin immediately upon issuance of a FERC Order because additional planning and permit would be necessary.²⁵⁹¹ There is no basis for the Commission to conclude it is unreasonable to replace the transformer.

5.5 Natural Gas and Solar Generation Operations Costs

PG&E's fossil fleet consists of two combined cycle plants, the Gateway Generating Station (Gateway or GGS) and the Colusa Generating Station (Colusa or CGS), and the Humboldt Bay Generating Station (Humboldt or HBGS) which uses reciprocating engine technology. The two combined cycle facilities are among the most efficient gas-fired plants in the state, allowing for displacement of energy from older, less efficient plants, and facilitating the integration of intermittent renewable resources. HBGS provides critical reliability support for the Eureka area.²⁵⁹² In addition to the fossil facilities, PG&E's generation fleet includes ten ground-mounted PV solar stations (which range from 2 to 20 MW), three small PV generation facilities and two fuel cell facilities located at San Francisco State University and California State University East Bay.²⁵⁹³

²⁵⁸⁹ PG&E-18, p. 4-27, line 14 to p. 4-28, line 12.

²⁵⁹⁰ CalTrout-1E, p.10, line 13 to p. 13, line 6.

²⁵⁹¹ PG&E-18, p. 4-28, lines 4-12.

²⁵⁹² PG&E-05, p. 5-1, lines 12-19.

²⁵⁹³ PG&E-05, p. 5-1, lines 22-27.

PG&E requests that the Commission approve the updated decommissioning forecast of \$153.5 million of remaining liability for the natural gas plants (\$52.2 million) and the PV solar stations (\$101.3 million).²⁵⁹⁴ This request is undisputed, is reasonable and should be adopted.

5.5.1 Natural Gas And Solar O&M Expense

PG&E's natural gas and solar O&M expense forecast covers the direct operations and maintenance expenses for Gateway, Colusa, Humboldt, and the solar stations. PG&E's TY 2023 expense forecast is \$52.258 million.²⁵⁹⁵ PG&E's TY 2023 forecast presented in the JCE is \$59.707 million.²⁵⁹⁶ PG&E's expense forecast is undisputed. TURN has agreed to PG&E's forecast as a part of the Energy Supply Stipulation.

5.5.2 Natural Gas And Solar Capital Expenditures

PG&E's original natural gas and solar capital expenditures forecast was \$10.033 million in 2021, \$5.370 million in 2022, \$6.336 million in 2023, \$9.181 million in 2024, \$9.734 million in 2025, and \$7.386 million in 2026.²⁵⁹⁷ PG&E's capital expenditures forecast presented in the JCE is \$10.969 million in 2021, \$6.354 million in 2022, and \$7.462 million in 2023.²⁵⁹⁸ PG&E's capital forecast is tracked in five MWCs, four of which are undisputed.²⁵⁹⁹

The one disputed capital expenditure forecast was for MWC 2S. PG&E's forecast for MWC 2S was \$3.640 million in 2023, \$7.929 million in 2024, \$8.568 million in 2025, and

²⁵⁹⁴ PG&E-05, WP 5-66, line 33.

²⁵⁹⁵ PG&E-18, p. 5-2, Table 5-1, line 10.

²⁵⁹⁶ PG&E-64, p. 3-3, Table 3A-1, lines 120-127.

²⁵⁹⁷ PG&E-18, p. 5-20, Table 5-6, line 9.

²⁵⁹⁸ PG&E-64, p. 3-15, Table 3B-3, lines 90-94 (2021); p. 3-11, Table 3B-2, lines 90-94 (2022); p. 3-7, Table 3B-1, lines 90-94 (2023).

²⁵⁹⁹ The undisputed MWCs are MWC 05, Tools and Equipment; MWC 2T, Install/Replace Fossil Buildings and Grounds Infrastructure; MWC 3A, Install/Replace AltGen Safety and Regulatory; and MWC 3B, Install/Replace AltGen Generating Equipment. *See* Appendix A.

\$6.196 million in 2026.²⁶⁰⁰ TURN recommended reductions of \$3.235 million in 2023, \$2.347 million in 2024, \$2.854 million in 2025, and \$4.447 million in 2026 based on its proposals to reduce by 16% PG&E’s forecasts for replacement engine emissions modules and to eliminate PG&E’s forecast for emergent work.²⁶⁰¹

The Energy Supply Stipulation, adopts TURN’s proposal to reduce HBGS Emissions module replacement costs by 16% resulting in the following reduction: \$0.235 million, \$0.347 million, \$0.354 million, and \$0.361 million for 2023, 2024, 2025, and 2026, respectively. In addition, the parties agree to a 50% reduction in emergent work capex forecast in MWC 2S resulting in the following reduction: \$0 million, \$2.0 million, \$2.5 million, and \$4.1 million for 2023, 2024, 2025, and 2026, respectively. Based on these agreements, TURN and PG&E propose a MWC 2S forecast of \$3.405 million, \$5.582 million, \$5.714 million, and \$1.735 million for 2023, 2024, 2025, and 2026, respectively, and a total Fossil/Solar capital expenditure forecast of \$6.100 million, \$6.834 million, \$6.879 million, and \$2.925 million for 2023, 2024, 2025, and 2026, respectively. Based on these agreements, PG&E and TURN have agreed to reduce the hydro operations capital expenditure forecast as indicated in Table 5-9 below.

TABLE 5-9
STIPULATED NATURAL GAS AND SOLAR GENERATION OPERATIONS CAPITAL
FORECAST
(THOUSANDS OF NOMINAL DOLLARS)^(a)

Party	2020 Rec.	2021	2022	2023	2024	2025	2026
PG&E Original Forecast	\$15,975	\$10,033	\$5,370	\$6,336	\$9,181	\$9,734	\$7,386
TURN recommended Reductions		\$(3,223)	\$(3,270)	\$(3,235)	\$(2,347)	\$(2,854)	\$(4,447)
Joint Recommended Reductions				\$(235)	\$(2,347)	\$(2,854)	\$(4,461)
Total Adjusted Forecast	\$15,975	\$10,033	\$5,370	\$6,100	\$6,834	\$6,879	\$2,925
(a) PG&E-18, p. 5-3, Table 5-2, line 9 and PG&E-18, p. 5-20, Table 5-6, line 9 and TURN-14, p. 9, Table 4.							

²⁶⁰⁰ PG&E-18, p. 5-20, Table 5-6, line 4.

²⁶⁰¹ PG&E-18, p. 5-3, Table 5-2, line 4.

We request that the Commission adopt the stipulated total 2023 adjusted natural gas and solar generation capital expenditure forecast agreed to by TURN and PG&E. The stipulated outcome is fully supported by evidence in the record.²⁶⁰²

5.5.3 Gateway Evaporative Cooling Project

PG&E's original forecast included funding for the Gateway Evaporative Cooling project.²⁶⁰³ TURN recommended removal of PG&E's 2021-2023 forecast, \$3.0 million each year, for the Gateway Evaporative Cooling Project. In rebuttal testimony, PG&E agreed with TURN and decreased its 2021, 2022 and 2023 forecasts by \$3.0 million each year.²⁶⁰⁴ In addition to its proposed reduction of the forecasts for this project, TURN asserted that PG&E should not be allowed to include forecasts for generation projects in its GRC that have not been vetted first through the Commission's Integrated Resource Planning (IRP) process.²⁶⁰⁵

In the Energy Supply Stipulation, PG&E agrees to implement its concession in rebuttal to remove the forecast for the Gateway Evaporative Cooling project. PG&E also agrees:

- Unless otherwise directed by the Commission, (1) new utility-owned generation capacity projects greater than 5 MW; or (2) new utility-owned generation capacity projects that are forecast to exceed \$20 million; or (3) utility owned generation projects that increase facility nameplate capacity by greater than 10%; or (4) utility owned generation projects that increase facility nameplate capacity that are forecast to exceed \$20 million, must be proposed in the Integrated Resource Plan proceeding or other proceeding that authorizes procurement (including, but not limited to, the Renewable Portfolio Standard Proceeding, or Resource Adequacy Proceeding or separate application), before requesting funding for the project in a GRC. This provision does not apply to reliability or efficiency projects (such as hydro turbine runner replacement or step-up transformer replacement).

²⁶⁰² PG&E-05, p. 5-6, line 1 to p. 5-9, line 23 and p. 5-54, line 14 to p. 5-61, line 7; PG&E-18, p. 5-5, line 10 to p. 5-16, line 10.

²⁶⁰³ PG&E-05, p. 5-58, lines 23-31.

²⁶⁰⁴ PG&E-18, p. 5-1, lines 22-25.

²⁶⁰⁵ TURN-14, p. 7, line 21 to p. 8, line 3 and JCCA-01, p. 24, lines 15-17.

We request that the Commission adopt the stipulated expense forecast, as well as the compromise agreed to by PG&E and TURN regarding certain capacity-related generation projects. The stipulated outcome is fully supported by the record.

5.5.4 Long Term Service Agreement (MWC KL)

MWC KL (Maintain Fossil Generating Equipment) is used for expense costs for planning and performing maintenance of PG&E's natural gas generation facilities, including materials and required contracts such as the Long-Term Service Agreements (LTSA) and other maintenance and engineering services.²⁶⁰⁶ The 2023 expense forecast for MWC KL is \$29.500 million.²⁶⁰⁷ This forecast is undisputed.

LTSA's are commonly used in the industry to provide high reliability and efficiency for combined cycle power plants. The LTSA's provide an effective cost and risk control measure for the major planned and unplanned maintenance activities at Gateway and Colusa Generating Stations. The LTSA's cover all the planned maintenance costs for the combustion turbines and steam turbines and include all inspections, maintenance, replacements and/or repairs due to wear and tear. General Electric performs planned maintenance inspections and repairs over the term of the LTSA's.²⁶⁰⁸

In addition to its expense forecast, PG&E requested that the Commission authorize PG&E to adjust on a prospective basis the schedule for amortization of LTSA milestone payments so that PG&E can true-up its recovery of milestone payments in the next GRC. PG&E's proposal requested adjustment only when PG&E's natural gas plants are operated more than expected.²⁶⁰⁹ TURN recommended that both upward and downward adjustments in the amortization of the milestone payments should occur consistent with the actual performance of

²⁶⁰⁶ PG&E-05, p. 5-47, lines 16-18.

²⁶⁰⁷ PG&E-18, p. 5-19, Table 5-5, Line 3.

²⁶⁰⁸ PG&E-18, p. 5-16, lines 13-20.

²⁶⁰⁹ PG&E-05, p. 5-51, lines 5-9.

the combined cycle units. In rebuttal testimony, PG&E agreed with TURN's recommendation that both upward and downward adjustments in the amortization of the milestone payments should occur consistent with the actual performance of the combined cycle units.²⁶¹⁰ This agreement is reflected in the provision of the Energy Supply Stipulation in which PG&E agrees to implement concessions made in rebuttal testimony regarding milestone payments for the LTSA.

We request that the Commission adopt the stipulated position regarding amortization of the LTSA milestone payments. The stipulated outcome is supported by the record.

5.6 Energy Procurement And Administration Costs

The Energy Policy and Procurement (EPP) organization is responsible for planning, management and administration of PG&E's electric and natural gas supply portfolios. It is responsible for both front-office and back-office functions associated with energy procurement. Front office functions include planning, procuring, scheduling, and dispatching electricity and natural gas for PG&E's customers. Back-office functions include administering procurement agreements and ensuring that timely and accurate payments are made to the California Independent System Operator, the Intercontinental Exchange's exchange and clearing agency and third-party suppliers. EPP is also responsible for long term planning, policy development, and compliance functions related to PG&E's energy portfolio, along with supporting internal development of PG&E's various strategic initiatives and public policy positions.²⁶¹¹

5.6.1 Energy Procurement And Administration Expense Costs

PG&E's TY 2023 expense forecast for EPP as reflected in rebuttal testimony is \$43.786 million.²⁶¹² PG&E's TY 2023 forecast in the JCE is \$44.537 million.²⁶¹³ The 2023 increase is

²⁶¹⁰ PG&E-18, p. 5-17, line 20.

²⁶¹¹ PG&E-05, p. 6-7, line 24 to p. 6-8, line 2.

²⁶¹² PG&E-18, p. 6-3, Table 6-1, line 5.

²⁶¹³ PG&E-64, p. 3-3, Table 3A-1, lines 128-131.

a \$3.1 million increase over recorded 2020 costs.²⁶¹⁴ The primary drivers of the increase are escalation due to inflation, increased staffing levels, and lower non-labor costs.²⁶¹⁵ PG&E's expense forecast is tracked in four MWCs, three of which are undisputed: MWC AB, Miscellaneous Capital; MWC CT, Acquire and Manage Electric Supply; and MWC CY, Manage Electric Grid Operations. See Appendix A.

5.6.1.1 Acquire and Manage Gas Supply (MWC CV)

MWC CV includes developing and executing gas purchase and hedging plans to acquire gas supplies, pipeline, and storage services; initiating and maintaining contracts with suppliers; scheduling the receipt and delivery of natural gas supplies on pipelines and storage fields; optimizing pipeline and storage assets to balance customer demands and meet pipeline requirements; selling excess gas supply and releasing unused pipeline transportation capacity; representing PG&E in regulatory matters and preparing and filing various compliance reports.²⁶¹⁶ Cal Advocates was the only party that disputed MWC CV as indicated in Table 5-10 below:

TABLE 5-10
ACQUIRE AND MANAGE NATURAL GAS SUPPLY (MWC CV) –
PG&E'S FORECAST AND PARTIES' RECOMMENDED REDUCTIONS (\$000s)^(a)

Party	2023
PG&E	\$2,445
Cal Advocates	\$(918)
(a) PG&E-18, p. 6-8, Table 6-2, line 3 (2020-2023 costs); p. 6-3, Table 6-1, line 3 (Cal Advocates' recommendation).	

PG&E initially forecast \$3,130 million for MWC CV in TY 2023. PG&E's original forecast included the cost of five additional staff members to support implementation of PG&E's

²⁶¹⁴ PG&E-18, p. 6-8, Table 6-2, line 5.

²⁶¹⁵ PG&E-05, p. 6-3, lines 6-8.

²⁶¹⁶ PG&E-18, p. 6-4, lines 9-16.

biomethane program. Cal Advocates challenged the need for the additional staff members.²⁶¹⁷ PG&E disagrees with Cal Advocates on all counts because the biomethane program represents a substantial increase in workload for PG&E's gas procurement function. PG&E agreed in rebuttal testimony to modify its EPP expense request to eliminate the cost of additional staff to implement the biomethane program because the Commission authorized balancing account recovery for the administrative costs of the biomethane program.²⁶¹⁸ The correct reduction to the TY 2023 EPP expense forecast is \$0.685 million, not \$0.918 million as Cal Advocates proposes,²⁶¹⁹ because \$0.918 million is the sum of PG&E's 2022 forecast and its TY 2023 forecast for additional staffing.²⁶²⁰

The Commission should adopt PG&E's adjustment of \$0.685 million to PG&E's TY 2023 expense forecast for EPP as an accurate reflection of PG&E's removal from recovery in GRC rates of the cost of 5 additional staff to support implementation of PG&E's biomethane program.²⁶²¹

5.7 Energy Supply Technology Programs

The Technology Programs in ES address the technology needs and initiatives of three PG&E business areas within ES: Nuclear Generation, Power Generation and EPP. ES systems support the operational processes critical to the Company's generation of electric and procurement of electric and gas supply and allow PG&E to deliver energy to its customers in a safe, reliable, clean, and affordable manner.²⁶²² PG&E's TY 2023 expense forecast as reflected

²⁶¹⁷ CALPA-08, p. 25, line 1 to p. 26, line 14.

²⁶¹⁸ PG&E-18, p. 6-6, lines 23-28.

²⁶¹⁹ CALPA-08, p. 26, lines 4-5.

²⁶²⁰ PG&E-18, p. 6-7, lines 7-10.

²⁶²¹ PG&E-18, p. 6-3, Table 6-1.

²⁶²² PG&E-05, p. 7-1, lines 11-17.

in opening testimony is \$2.793 million.²⁶²³ PG&E's TY 2023 forecast in the JCE is \$2.960 million.²⁶²⁴

PG&E's expense forecast is tracked in MWC JV, Maintain IT Applications and Infrastructure, and is undisputed. See Appendix A.

PG&E capital expenditures forecast as reflected in opening testimony is \$12.320 million in 2021, \$15.0 million in 2022, and \$14.1 million in 2023.²⁶²⁵ PG&E's capital expenditures forecast presented in the JCE is \$12.696 million in 2021, \$17.417 million in 2022, and \$17.063 million in 2023.²⁶²⁶ PG&E's capital forecast is tracked in MWC 2F, Build IT Applications and Infrastructure, and is undisputed. See Appendix A.

5.8 Energy Supply Ratemaking²⁶²⁷

5.8.1 Hydro Decommissioning Accrual

The intent of a hydro decommissioning reserve is to accrue decommissioning funds while the plant is used and useful; therefore the annual accrual calculation is generally based on the forecast retirement dates rather than the earliest decommissioning start year.²⁶²⁸ In PG&E's last GRC, the Commission approved the establishment of a hydro decommissioning reserve and initial annual accrual of \$10 million.²⁶²⁹ No parties have opposed PG&E's request to continue to continue to accrue for hydro decommissioning. PG&E's proposal and estimate in this case maintains the following foundational assumptions for the decommissioning reserve model: (1)

²⁶²³ PG&E-05, p. 7-25, Table 7-5, line 2.

²⁶²⁴ PG&E-64, p. 3-3, Table 3A-1, lines 128-131.

²⁶²⁵ PG&E-05, p. 7-26, Table 7-6, line 2.

²⁶²⁶ PG&E-64, p. 3-15, Table 3B-3, line 95 (2021); p. 3-11, Table 3B-2, line 95 (2022); p. 3-7, Table 3B-1, line 95 (2023).

²⁶²⁷ PG&E includes discussion of nuclear ratemaking proposals in section 5.3.3 of this brief.

²⁶²⁸ PG&E-05, p. 8-13, lines 14-17.

²⁶²⁹ D.20-12-005, pp. 153-154.

estimate is based on the projects and powerhouses under 30 MW and in the portfolio as of December 31, 2020; (2) the scope includes only physical decommissioning activities (costs of licensing activities recovered through the hydro licensing balancing account) and in many cases does not assume full project removal; and (3) the time frame for decommissioning will be 15 years.²⁶³⁰ In its refinement of the model for this GRC, PG&E used both project-specific decommissioning cost estimates and a cost model that evaluates the costs of various decommissioning scenarios and also applied a decommissioning probability factor.²⁶³¹ Based on these assumptions, PG&E proposed recovery of an annual accrual of \$62.2 million for the hydro decommissioning reserve.²⁶³²

Cal Advocates proposed reducing the annual accrual to \$23.9 million, which recommended a total cost of \$97.5 million in nominal dollars for the Battle Creek project and recovery over two GRC periods (8 years).²⁶³³ CalTrout²⁶³⁴ proposed that the probability factor applied to the Potter Valley decommissioning estimate be increased from 20 to 100 percent and that the decommissioning cost estimate itself be increased to the range of \$133.9 million to \$155.8 million in real dollars.²⁶³⁵

PG&E, Cal Advocates, and CalTrout reached a stipulation in which the parties agree that, for purposes of the record period 2023-2026, a total annual accrual of \$48 million reflects a reasonable resolution of the issues raised in this proceeding regarding the total annual accrual

²⁶³⁰ PG&E-05, p. 8-12, lines 2-22.

²⁶³¹ PG&E-05, p. 8-13, line 19 to p. 8-17, line 23.

²⁶³² PG&E-18, p. 8-3, lines 3-4.

²⁶³³ CALPA-15, p. 3, lines 6-9.

²⁶³⁴ For purposes of this brief, PG&E's references to CalTrout includes Friends of the Eel River and Trout Unlimited.

²⁶³⁵ CalTrout-02, p. 3, lines 9-10 and p. 7, line 13.

into the hydro decommissioning reserve.²⁶³⁶ This is higher than Cal Advocates' hydro accrual proposal and lower than that of PG&E and CalTrout. This stipulation resolved the disputed issues on the hydro decommissioning reserve and should be adopted by the Commission as it represents a reasonable outcome of disputed issues and is consistent with its approval of a hydro decommissioning accrual for hydroelectric assets.²⁶³⁷

5.8.2 Hydro Licensing Balancing Account

The HLBA is a two-way balancing account authorized by the Commission to manage the capital and expense forecasts related to FEC hydro licensing activities.²⁶³⁸ In the 2020 GRC, the Commission approved a settlement that expanded the scope of the HLBA to include costs associated with the Crane Valley Settlement Agreement and with regulatory fees and costs related to the Oroville Dam spillway incident.²⁶³⁹

PG&E originally requested authority to continue HLBA treatment as previously authorized by the Commission. In addition, PG&E proposed to include in the HLBA costs resulting from settlement agreements associated with issuance of a FERC license, regardless of the date of license issuance.²⁶⁴⁰ TURN recommended that the Commission revise the HLBA to a one-way balancing account. With a one-way balancing account, amounts in excess of the forecasts authorized in the GRC would be tracked in a memorandum account and cost recovery reviewed in the next GRC.²⁶⁴¹ Alternatively, TURN proposed a 90/10 sharing mechanism for amounts in excess of the forecasts authorized in the GRC, with customers responsible for 90%

²⁶³⁶ PG&E-30, p. 2.

²⁶³⁷ D.20-12-005, pp. 153-154.

²⁶³⁸ PG&E-05, p. 8-10, lines 3-5, citing D.14-08-032, p. 736, OPs 24-27.

²⁶³⁹ D.20-12-005, pp. 135-136.

²⁶⁴⁰ PG&E-05, p. 8-11, lines 3-33.

²⁶⁴¹ TURN-14, p. 89, lines 3-10.

and shareholders 10% of the excess.²⁶⁴² TURN also proposed to limit the type of projects that can flow through the HLBA to those associated with implementing new license conditions,²⁶⁴³ specifically excluding costs related to the Oroville Dam incident and settlement agreements.

As part of the Energy Supply Stipulation, TURN and PG&E have agreed to the following regarding the HLBA:

- The Hydro License Balancing Account (HLBA) will be retained as a 2-way balancing account. If the actual combined capital and expense revenue requirements at the end of each two-year period is less than authorized, then the difference is refunded to customers. If the actual combined capital and expense revenue requirements at the end of each two-year period exceed authorized by 20% or less, then customers would be charged for the shortfall in future rates. If the actual combined capital and expense revenue requirements at the end of each two-year period exceed authorized by more than 20%, the overages would be subject to reasonableness review through a tier 3 advice letter. Any party protesting a tier 3 advice letter may request that the Commission instead consider the reasonableness of the spending in a subsequent application. If found reasonable, then customers would be charged for the shortfall in future rates. This would not be precedent setting for any other PG&E balancing accounts. A memorandum account would be used to track the overage. No change to the types of costs currently recorded to the HLBA.
- Withdrawal of proposal to include pre-2012 license condition settlement amounts in HLBA. PG&E has not included a forecast for this work in the GRC.

The stipulated outcome is fully supported by record evidence and should be approved.²⁶⁴⁴

5.8.3 Helms Capacity Memorandum Account

PG&E proposed to establish the Helms Capacity Memorandum Account (HCMA), effective January 1, 2023, to record costs in connection with the uprate of the three existing units at Helms Pumped Storage Facility (Helms).²⁶⁴⁵ The project is still in preliminary phases of analysis, but the Helms Uprate has an expected-case scenario of 1 unit coming online in 2027, 1

²⁶⁴² TURN-13, p.26, lines 2-6.

²⁶⁴³ TURN-14, p. 12, Table 6 and p. 13, Table 7.

²⁶⁴⁴ PG&E-05, p. 4-72 to p. 4-75 and p. 8-10 to p. 8-11.

²⁶⁴⁵ PG&E-05, p. 8-18, lines 3-5.

unit in 2028, and 1 unit in 2029.²⁶⁴⁶ PG&E has not yet developed a detailed scope, schedule and forecast for this unique project but is evaluating alternatives in response to the CPUC's identified need for incremental long duration storage.²⁶⁴⁷ To achieve online dates in 2027 through 2029 for the three units, work on the uprate project will occur in the 2024-2026 time period. While the uprated units may not be operational until 2027 or beyond, without the memorandum account, PG&E doesn't have the opportunity to request recovery of costs for this project through a future application.²⁶⁴⁸

TURN recommended that the Commission reject PG&E's request for the HCMA because PG&E has not included a forecast for the underlying work in this GRC, and CWIP and AFUDC provide adequate cost recovery opportunities.²⁶⁴⁹

As part of the Energy Supply Stipulation, PG&E has agreed to withdraw its request to establish the HCMA and TURN agrees that PG&E may seek recovery of the reasonable costs associated with the Helms uprate project if the project is cost effective and PG&E has sought approval for the project in a CPUC proceeding.

The stipulated outcome is fully supported by the evidence in the record and represents a reasonable compromise of disputed issues.

5.8.4 Utility Owned Generation Vintaging

PG&E's application and supporting testimony in this proceeding did not include any recommendations regarding the vintages assigned to PG&E's Utility Owned Generation (UOG) for purposes of calculating the Power Charge Indifference Adjustment (PCIA) because PG&E does not propose any changes to the vintaging or the current framework for assigning cost

²⁶⁴⁶ PG&E-18, p. 8-13, lines 7-9.

²⁶⁴⁷ PG&E-05, p. 8-17, lines 25-29, citing R.20-05-003, Decision Requiring Procurement to Address Mid-Term Reliability (2023-2026).

²⁶⁴⁸ PG&E-18, p. 8-13, lines 5-23.

²⁶⁴⁹ TURN-13, p. 29-30; TURN-14, pp. 38-41.

responsibility to bundled and unbundled customers for UOG.²⁶⁵⁰ PG&E supports continuation of the current approach that was directed by the Commission in D.18-10-019. The current approach appropriately ensures that customers pay for the costs of investments made on their behalf, including the costs of decommissioning a resource. In contrast, the Joint Community Choice Aggregators (JCCA)²⁶⁵¹ proposals would allow CCA customers to avoid financial responsibility for investments made to serve CCA customers – and that continue to benefit them – by shifting the ongoing costs of these assets to bundled customers. This is inconsistent with law and Commission precedent.

JCCA characterized its interest in this proceeding as in connection with PG&E’s distribution and generation revenue requirements.²⁶⁵² Specific to the generation revenue requirement, the JCCAs propose that the Commission adopt a new vintaging framework to be applied in future GRCs. Under this proposed framework, certain commitments or changes to UOG resources would trigger reconsideration of that facility’s vintage assignment.²⁶⁵³ JCCA also recommends that the Commission designate a new vintage assignment to 12 hydro plants based on future life extension assumptions for these plants included in PG&E’s depreciation study.²⁶⁵⁴

5.8.4.1 JCCA Proposals Unlawfully Shift Costs To Bundled Customers

If adopted, the JCCA proposals would not impact the overall generation revenue requirement authorized in this proceeding. Instead, the JCCA proposals would exempt CCA

²⁶⁵⁰ Exhibit JCCA-22.

²⁶⁵¹ JCCA includes eight community choice aggregators operating in PG&E’s service territory: The City and County of San Francisco, East Bay Community Energy, Marin Clean Energy, Peninsula Clean Energy Authority, Pioneer Community Energy, San Jose Clean Energy, Silicon Valley Clean Energy Authority, and Sonoma Clean Power Authority.

²⁶⁵² JCCA-01, p. 1, line 26 to p. 2, line 9.

²⁶⁵³ JCCA-01, p. iii.

²⁶⁵⁴ JCCA-01, pp. 33-44.

customers from cost responsibility for portions of the generation revenue requirement adopted in this proceeding for assets that provide benefits to CCA customers. The JCCA proposals therefore would shift costs incurred on behalf of unbundled customers to bundled customers in violation of the statutory directive that “bundled [] customers...shall not experience any cost increase as a result of the implementation of a community choice aggregator program.”²⁶⁵⁵

The JCCA proposals should be rejected. The Public Utilities Code sets out a comprehensive scheme governing the ways in which electricity is procured and provided to retail customers. Traditionally, IOUs “bundled” all the necessary electricity services—generation, transmission, and distribution—and delivered them to their retail customers. IOU customers who receive the full suite of electricity services from their providers are therefore referred to as “bundled customers.” In 2014, the Legislature revised the Public Utilities Code to allow retail customers to leave the electricity procurement service provided by IOUs for alternate service providers called CCAs. CCAs are entities formed by local governments to negotiate and purchase electricity for residents and businesses within their areas. In adopting this policy, the Legislature made clear that customers who leave IOUs for CCA service must pay their fair share of costs for the resources that the IOU already procured to serve them.²⁶⁵⁶ Customers who take electricity procurement service from CCAs are called “unbundled customers” or “departed load customers.”

Public Utilities Code provisions addressing the allocation of costs between bundled customers and departing load customers make clear that bundled service customers must not incur any costs for resource procurement decisions that were made on behalf of CCA customers. The explicit directive against cost shifting to bundled service customers appears throughout the Public Utilities Code. The Legislature’s express intent was to prevent any shifting of

²⁶⁵⁵ Pub. Util. Code § 366.3.

²⁶⁵⁶ Pub. Util. Code § 366.2.

recoverable costs between customers departing to CCAs and those remaining with IOUs' bundled service.²⁶⁵⁷ The Legislature carried out this intent by adopting not just one, but numerous statutory provisions mandating that bundled customers be held financially indifferent to unbundled customers. For example, the Legislature directed that CCA programs "shall not result in a shifting of costs between the customers of the community choice aggregator and the bundled service customers of an electrical corporation;"²⁶⁵⁸ that bundled customers "shall not experience any cost increase as a result of [CCA programs];"²⁶⁵⁹ and that the Commission "shall ensure" these customers "do not experience any cost increases" due to unbundled customers.²⁶⁶⁰ Each of these statutory provisions clearly prohibits cost shifting from CCA customers to bundled service customers. The breadth of the indifference mandate espoused in the statute is clear. Put simply, assets procured to serve customers who later departed for CCAs, which include both UOG costs and contracted procurement costs, must be recovered through the comprehensive PCIA methodology. Cost allocation principles prohibit the costs of investments incurred on behalf of departing load from being shifted solely to bundled service customer customers without limitation.

Based on these provisions prohibiting cost shifts, the Commission assesses a charge, called the Power Charge Indifference Adjustment (PCIA), charge or rate, to apportion certain above-market IOU generation costs between bundled and unbundled customers. The PCIA methodology works on a "total portfolio" basis, allocating to departing load customers a pro-rata share of the above-market costs of the UOG resources. The PCIA charge reflects the costs borne by IOUs to procure generation resources on behalf of the departing load, while also accounting for the market revenue or "benefits" of those resources that remain with bundled customers. To

²⁶⁵⁷ Pub. Util. Code § 366.2(d)(1).

²⁶⁵⁸ *Id.*, subdiv. (a)(4).

²⁶⁵⁹ Pub. Util. Code §366.3.

²⁶⁶⁰ Pub. Util. Code § 365.2.

develop the PCIA rate, which can be positive (a charge) or negative (a credit), UOG resources are assigned to a vintaged portfolio based on the year the generation resource commitment is made (i.e., contract execution date or Commission approval of UOG) and customers are assigned to a vintage based on their departure date. Specifically, customers who depart before July 1 of a given year are assigned to the prior year's vintage.²⁶⁶¹

5.8.4.2 There Is No Need to Adopt the JCCA Proposed Framework

JCCA suggests that the Commission adopt in this proceeding a general framework to be used in future GRCs to allocate the cost of ongoing investments in PG&E's UOG resources between bundled service and departing load customers for purposes of setting the PCIA cost recovery mechanism.²⁶⁶² The JCCA framework (1) defines a supposed "end-date" for all UOG resources and (2) identifies whether any new commitments/investments in UOG presented in a GRC trigger reconsideration of the facility's resource vintage assignment, whether the full revenue requirement or a portion thereof. Under the JCCA framework, an existing UOG resource must be re-vintaged when the utility makes a significant new commitment for that facility, which they defined as: (a) a change in the underlying purpose or use of the facility for the benefit of bundled customers, (b) a significant capacity addition to the facility's original capacity for the benefit of bundled customers, (c) an extension in the expected operating life of a facility.²⁶⁶³

The Commission need not adopt the framework as proposed by JCCA-or any framework or specific requirements at all-in order to consider whether investments in UOG resources justify assigning a different vintage to that resource to set the PCIA rate. The Commission has already found that any such analysis "must be fact-specific to the plants and spending in question and is

²⁶⁶¹ See generally D.16-09-044.

²⁶⁶² JCCA-01 pp. iii, lines 8-23.

²⁶⁶³ *Id.*

better suited to a GRC evaluating such spending”.²⁶⁶⁴ JCCA would like the Commission to identify circumstances in advance that create a rebuttable presumption that a facility should be re-vintaged, but the Commission has already determined this analysis should be on a “case-by-case” basis.

This makes sense because investments made to UOG resources vary significantly depending on the technology type, age, condition, design, geographical location, interconnection point environmental conditions, and regulatory restrictions.²⁶⁶⁵ To maintain the principles of cost causation and customer indifference, each investment must be assessed individually.²⁶⁶⁶

The Commission has already determined that specific investments proposed for UOG resources should be considered on a case-by-case basis in GRC proceedings. The Commission should reject JCCA’s proposals to specify in advance categories of investments/actions triggering re-vintaging as contrary to this finding and unnecessary.

5.8.4.3 PG&E’s Hydroelectric Assets Should Remain In The Legacy UOG Vintage

There is no basis to establish “triggers” for re-vintaging or for assigning hypothetical “end dates” upon which the above market costs of UOG resources will be excluded from the PCIA rate paid by, or credited to, departed load customers as JCCA proposes. The statutory requirement that the Commission “ensure that bundled retail customers of an electrical corporation do not experience any cost increases as a result of retail customers of an electrical corporation electing to receive service from other providers” is clear and unambiguous.²⁶⁶⁷ It is not limited in time, nor is it specific to any given resource type (i.e., renewable, conventional, etc.). There is no support for the notion that the Legislature’s intent in adopting the statutory

²⁶⁶⁴ D.18-10-019, p. 135.

²⁶⁶⁵ PG&E-18, p. 9-3, lines 8-12.

²⁶⁶⁶ *Id.*, lines 14-17.

²⁶⁶⁷ Pub. Util. Code § 365.2 (emphasis added); see also Pub. Util. Code §§ 366.2 and 366.3.

indifference requirement was to at some point shift full responsibility for the costs of PCIA-eligible resources to remaining bundled customers. Indeed, the plain language of Sections 365.2, 366.2 and 366.3 indicate exactly the opposite – that is, bundled customers may not experience “any cost increases” due to load departure.

The Commission’s obligation to preserve customer indifference applies so long as PCIA-eligible resources developed or procured to serve departing load customers remain in the utility’s portfolio, whether operating or being decommissioned. Even if the Commission adopts a date on which departed load customers should no longer be presumptively responsible for any portion of the ongoing revenue requirement to operate and maintain a UOG resource – and it should not – departing load customers must remain responsible for the decommissioning costs of UOG resources. The Commission must ensure that customers who received the benefit of energy and capacity from these resources also contribute to the cost to decommission them.²⁶⁶⁸ The omission of any recognition of departed load responsibility for decommissioning costs in the JCCA proposal renders the proposal incomplete and inadequate to ensure no shifting of costs to bundled customers.

5.8.4.3.1 Assuming An Extended Life For A Hydro Facility Is Not A New Commitment That Should Trigger Re-Vintaging

JCCA proposes that 12 of PG&E’s hydro facilities be assigned a new vintage based on the year of the GRC in which PG&E presented a depreciation study reflecting an extended life for these hydro facilities. In doing so, JCCA conflates Commission approval of a depreciation study with approval to continue operating those facilities. These are not the same thing. As a practical matter, there is no pre-defined end of life for a hydro facility. PG&E must continue complying with existing license requirements until the Federal Energy Regulatory Commission issues an order on its relicensing or surrender application.²⁶⁶⁹ Annual licenses are automatically

²⁶⁶⁸ PG&E-18, p. 9-8, lines 20-31.

²⁶⁶⁹ 16 U.S.C. § 808(a)(1).

issued until a new license is issued.²⁶⁷⁰ Additionally, the ongoing costs to maintain the dams and reservoirs necessary to support hydro facility operations do not change based on who the service provider is for customers in PG&E's service territory. Assigning a new vintage for a resource would effectively allow departed load to avoid paying for the eventual decommissioning of the resources as well. Such a result, exempting CCA customers from responsibility for a hydro facility revenue requirement based on an artificial relicensing date, would be arbitrary and violate the principles of maintaining customer indifference.²⁶⁷¹ Because these resources were procured to serve load that has since departed for CCAs, the principle of customer indifference requires that departed and bundled load customers continue to pay all costs, and receive benefits, associated with maintaining, operating and decommissioning these resources.

For all of these reasons, the Commission should reject the JCCA proposed generic revintaging framework and proposals.

5.8.5 Diablo Canyon Retirement Balancing Account

The Diablo Canyon Retirement Balancing Account (DCRBA) is a two-way balancing account established by the Commission to implement the approved ratemaking associated with the retirement of Diablo Canyon Power Plant (DCPP), including recovery of the DCPP Net Book Value. The approved ratemaking allowed amortization of the DCPP direct assigned net plant investment as of December 31, 2017 over the remaining life of the plant (through December 2024 for Unit 1 and December 2025 for Unit 2) and necessary capital additions in the 2018 through end-of life period.²⁶⁷² The difference in revenue requirements between the GRC-approved capital additions and the actual capital additions are tracked in the DCRBA.

²⁶⁷⁰ Id.

²⁶⁷¹ PG&E-18, p. 9-7, lines 27-30.

²⁶⁷² PG&E-05, p. 8-5, lines 20-27, citing D.18-01-022 at 46-47.

As discussed in Section 5.3.2, the Energy Supply Stipulation reflects PG&E's agreement to record and recover only the GRC-authorized capital expenditures in the DCRBA.

6. CUSTOMER AND COMMUNICATIONS (EXHIBIT PG&E-06)

Exhibit PG&E-06 presents Customer and Communication's expense and capital expenditures forecast to support customer strategy and communications across all lines of business and deliver a broad range of services, products, and support to approximately 16 million people in PG&E's service territory. PG&E submitted hundreds of pages of opening testimony and extensive, detailed workpapers in Exhibit PG&E-06 as well as rebuttal testimony in Exhibit PG&E-19 supporting Customer and Communication's programs and forecasts. The testimony and workpapers demonstrate that PG&E's forecasts are just and reasonable, as well as necessary, to provide customers with great customer service and experience.

6.1 Forecast

This section describes the Customer and Communications expense and capital expenditure forecasts and addresses programs and issues that have been disputed by the parties. PG&E's TY 2023 updated expense forecast for Customer and Communications is \$373.619 million,²⁶⁷³ of which \$225 million (60 percent) is uncontested.²⁶⁷⁴ PG&E's JCE (PG&E-64) forecast which includes PG&E's September 6, 2022, escalation adjustment is \$386.680 million.²⁶⁷⁵

PG&E's capital expenditures forecast is \$218.045 million in 2021, \$243.366 million in 2022, \$286.567 million in 2023, \$321.026 million in 2024, \$281.338 million in 2025, and \$262.245 million in 2026.²⁶⁷⁶ PG&E's JCE forecast for capital expenditures is \$226.012

²⁶⁷³ PG&E-64, p. 3-4, Table 3A-1, Total Exhibit (PG&E-06).

²⁶⁷⁴ See Appendix A, p. A-14, line 263. Calculated as: $\$225 / \$374 = 60$ percent

²⁶⁷⁵ PG&E-64, p. 3-4, Table 3A-1, Total Exhibit (PG&E-06).

²⁶⁷⁶ PG&E-06-E, p. 1-7, Table 1-2, line 7.

million in 2021, \$277.221 million in 2022, and \$338.811 million in 2023, \$379.387 million in 2024, \$326.279 million in 2025, and \$298.061 million in 2026.²⁶⁷⁷

6.2 Regional Vice Presidents

In 2021, PG&E launched a regional service model with five Regional Vice Presidents (RVPs) who live and work in their local communities and are actively engaged in the challenges and opportunities unique to their regions. The Commission directed PG&E to hire the RVPs in D.20-05-053.²⁶⁷⁸ PG&E's RVPs are embedded in the regions for which they are responsible and share direct accountability with our core functional organizations for their region's customer experience, as well as safety and operational performance.²⁶⁷⁹ The RVPs' roles are new. As PG&E witness Matthew Plummer explained, the activities performed by the RVPs during their "day-to-day are unique to them; meeting with employees, meeting with the community ... there was not [a vice president role] with specific accountability for a region" previously.²⁶⁸⁰

PG&E's TY 2023 expense forecast for the RVPs and their immediate offices is \$11.439 million, which consists of \$6.064 million for RVP Operational Management and \$5.375 for Customer and Communications Operational Management.²⁶⁸¹ Customer and Communications Operations and Maintenance forecasts are addressed in Section 6.9 below. PG&E's JCE forecast for RVP Operations and Maintenance is \$6.118 million.²⁶⁸² The expense forecast includes work tracked in MWC OM, Operational Management.

²⁶⁷⁷ PG&E-67, WP-4, Exhibit 6 Total.

²⁶⁷⁸ D.20-05-053, p. 112, OP 3.

²⁶⁷⁹ PG&E-06-E, p. 1A-5, lines 3-7.

²⁶⁸⁰ Tr. Vol. 7, p. 1331:5-12, PG&E/Plummer.

²⁶⁸¹ PG&E-19-E, p. 1A-2, Table 1A-1, lines 1-3.

²⁶⁸² PG&E-64, p. 3-4, Table 3A-1, line 164.

TURN disputes PG&E's MWC OM forecast and recommends disallowing \$1.747 million.²⁶⁸³ TURN argues that the RVPs' compensation should be disallowed because PG&E does not adequately address safety improvements in its Regionalization Plan.²⁶⁸⁴ But the Commission already considered and rejected similar arguments by TURN in connection with its approval of PG&E's Regionalization Plan and a multi-party settlement.²⁶⁸⁵ TURN should not get a second bite at this apple; the Commission already decided it.

TURN also objects to recovery of the RVPs' salary on the grounds that the utility had an inconsistent safety performance prior to the engagement of the RVPs and the Regionalization Plan will not "ensure improvements in its safety performance"²⁶⁸⁶ TURN's argument misses the point, PG&E has committed to improve safety performance through its regionalization.²⁶⁸⁷ Moreover, past safety performance is not a sufficient basis to deny cost recovery for future costs that PG&E will reasonably incur to provide customer service and improve safety in the regions.

Notably, TURN does not dispute either the amount of the RVP forecast or PG&E's forecast methodology. The Commission required PG&E to engage its RVPs as part of its Regionalization Plan,²⁶⁸⁸ which is exactly what the Company did in 2021.²⁶⁸⁹ Since that time, the RVPs have worked to effectuate PG&E's Regionalization Plan, including the safety benefits that will result from that plan. The Commission should adopt PG&E's full forecast for the RVPs as reasonable and prudent.

²⁶⁸³ TURN-15, p. 2, line 2.

²⁶⁸⁴ TURN-15, p. 6 line 14 to p. 7, line 5.

²⁶⁸⁵ D.22-06-028, pp. 21-22.

²⁶⁸⁶ TURN-15, p. 7, lines 2-3.

²⁶⁸⁷ Tr., Vol. 7, 1325:21-24, PG&E/Plummer.

²⁶⁸⁸ D.20-05-053, p. 52.

²⁶⁸⁹ PG&E-06-E, 1A-7, ln. 13-14.

6.3 Customer Engagement

Customer Engagement supports a variety of program areas including, for example, services to small and medium businesses, Public Safety Power Shutoff planning and readiness, economic development, resources to support customers who have or are interested in distributed generation, and clean energy transportation. Customer Engagement also provides essential services and benefits to PG&E's customers through direct customer service and programs.

PG&E's TY 2023 expense forecast is \$101.830 million. PG&E's JCE forecast is \$107.876 million.²⁶⁹⁰ Cal Advocates and TURN dispute PG&E's forecast and propose the below reductions.

TABLE 6-1
CUSTOMER ENGAGEMENT: PG&E'S EXPENSE FORECAST AND PARTIES
RECOMMENDED REDUCTIONS (\$000s)^(a)

Party	2020 Rec.	2021	2022	2023
PG&E	\$78,701	\$113,901	\$91,530	\$101,830
Cal Advocates				\$(9,685)
TURN ^(b)				\$(8,944)
(a) PG&E-19-E, p. 2-15, Table 2-5, line 10; p. 2-3, Table 2-1, line 8.				
(b) TURN's recommended forecast reduction for MWC EL as shown in PG&E's rebuttal testimony is \$(8,800) whereas it is \$(8,838) in the JCE. PG&E-19-E, p. 2-3, Table 2-1, line 2; PG&E-64, p. 2-444.				

PG&E's TY 2023 capital expenditure forecast is \$8.550 million. PG&E's JCE forecast is \$10.347 million.²⁶⁹¹ TURN and Cal Advocates dispute PG&E's forecast and proposes the following reductions:

²⁶⁹⁰ PG&E-64, Table 3A-1, p. 3-4, lines 133-139.

²⁶⁹¹ PG&E-64, Table 3B-1, p. 3-8, lines 96-97.

TABLE 6-2
EV STATION INFRASTRUCTURE: PG&E'S CAPITAL FORECAST AND PARTIES
RECOMMENDED REDUCTIONS (\$000s)^(a)

Party	2020 Rec.	2021	2022	2023	2024	2025	2026
PG&E	\$2,928	\$2,400	\$2,300	\$8,550	\$9,360	\$4,650	\$5,900
TURN				\$(6,250)	\$(6,960)	\$(2,150)	\$(3,300)
Cal Advocates				\$(2,300)			
(a) PG&E-19-E, p. 2-16, Table 2-6, line 2; p. 2-4, Table 2-2, line 1.							

Cal Advocates' and TURN's proposed reductions are associated with three programs within Customer Engagement: (1) Non-Tariffed Products and Services (NTP&S); (2) PG&E's Electric Vehicle Infrastructure Program (EVIP); and (3) Internal Fleet Electrification Program (Internal Fleet Program). These three disputed programs are addressed below.

6.3.1 Non-Tariffed Products And Services

PG&E offers NTP&S programs through its New Revenue Development Department (MWC EL). The NTP&S program primarily uses underutilized PG&E assets or capacity, such as distribution poles, to generate incremental revenues by marketing products and services to third parties (*e.g.*, the short-term use of PG&E facilities or real property). This program benefits customers, because the revenue from these third-party transactions offsets associated NTP&S program expenses (*e.g.*, invoicing, contract administration, etc.), and the net revenue in excess of expenses is credited back to customers on a forecast basis.

PG&E's forecast considers historical averages and performance for revenue and expense, as well as existing customer agreements and business development activity, to project the reasonable probability of executing additional NTP&S agreements.

PG&E also continues to see growth in demand for the existing products.²⁶⁹² Cal Advocates recommends a forecast reduction based on a three-year average of recorded costs for NTP&S (2018-2020) and asserts that PG&E did not substantiate its anticipated increase in

²⁶⁹² PG&E-19-E, p. 2-7, lines 1-6.

demand from third-parties for products and services.²⁶⁹³ While third-party demand for products may vary in the future, PG&E's testimony shows that the MWC EL expense trend is increasing year-over-year, as is demand and the associated MWC EL revenues.²⁶⁹⁴ Thus, simply relying on the 2018-2020 historical average is an incomplete method for forecasting for this program. To more accurately capture the entire growth projection, PG&E's forecast considers both historical averages and the expected increasing demand for products and services. Cal Advocates' forecast fails to contemplate the reality of this business growth; having failed to consider all relevant factors, it should be rejected.

TURN recommends a reduction based on 2020 recorded costs, claiming that there will be a revenue reduction from NTP&S in 2023.²⁶⁹⁵ TURN asserts that revenues will decrease as a result of the February 2021 transaction between PG&E and SBA Communications Corporation (SBA) in which SBA paid upfront for long-term rights to use PG&E facilities. TURN argues that authorizing an increase in expense is inappropriate due to an anticipated reduction in NTP&S wireless revenues.²⁶⁹⁶

TURN's assumptions are incorrect. Customers will receive increased proceeds from that transaction. For example, PG&E's 2023 revenue forecast includes a \$5.9 million credit for the SBA transaction, which is substantially higher than the \$2.8 million revenue credit customers received for rent revenues prior to the SBA transaction.²⁶⁹⁷ More importantly, the fact that PG&E's annual revenues from NTP&S products and services are decreasing does not mean that expenses will decrease in lock step. PG&E is continuing to incur costs to provide products and services to third parties and has reasonably forecasted that these costs will increase during the

²⁶⁹³ CALPA-09, p. 9, lines 13-15.

²⁶⁹⁴ PG&E-19-E, p. 2-6, lines 25-27.

²⁶⁹⁵ TURN-15, p. 7, lines 17-18.

²⁶⁹⁶ TURN-15, p. 8, lines 16-19.

²⁶⁹⁷ PG&E-19-E, p. 2-7, lines 21-26; p. 2-8, lines 13-18.

rate case period.²⁶⁹⁸ Other than referring to the decline in revenue forecasts, TURN does not offer any evidence that PG&E’s expense forecasts themselves are unreasonable.

6.3.2 The Electric Vehicle Infrastructure Forecast Is Just And Reasonable.

PG&E’s Electric Vehicle Infrastructure Program (EVIP) involves the installation of a new EV charging infrastructure that can be used by fleet vehicles as well as PG&E employees. This program is consistent with Commission and state policies encouraging the rapid deployment of EVs in California. The Commission opened its first rulemaking pertaining to alternative-fueled vehicles in 2009.²⁶⁹⁹ Since then, “the Commission has been increasing its efforts in response to directives from the Governor’s office and the California Legislature.”²⁷⁰⁰ The Governor’s Executive Order No. N-79-20 set the aggressive goal that 100 percent of California sales of new passenger cars and trucks be zero-emission by 2035 and all medium and heavy-duty vehicles, where feasible, to zero-emission by 2045.²⁷⁰¹ We are developing EV infrastructure so that our fleet vehicles and employees have access to the facilities necessary to support the Governor’s energy policy on EVs.

Cal Advocates recommends that the Commission reject PG&E’s entire 2023 forecast for EVIP on the grounds that “the project is a burden to ratepayers because it does not provide any verifiable benefits or calculated savings that outweigh the costs ratepayers are being requested to pay.”²⁷⁰² Cal Advocates is incorrect. PG&E’s capital forecast for EVIP furthers the Commission’s and California’s policy goals by preparing for the electrification of our fleet and employee’s vehicles through the installation of EV charging stations. This allows employees to charge their EVs, or fleet EVs, during lower cost, off peak hours. The installation of this

²⁶⁹⁸ PG&E-19-E, p. 2-8, lines 6-7.

²⁶⁹⁹ R.09-08-009, *Order Instituting Rulemaking* (Issued Aug. 24, 2009).

²⁷⁰⁰ R.18-12-006, *Order Instituting Rulemaking*, p. 2 (Issued Dec. 19, 2018).

²⁷⁰¹ Governor’s Executive Order No. N-79-20 (Sept. 23, 2020).

²⁷⁰² CALPA-09, p. 14, lines 14-16.

charging infrastructure provides employees a reasonable and efficient way to recharge their vehicles for their commutes. California's accelerated clean transportation goals make the EVIP program a critical tool for increasing the speed and scale necessary to electrify PG&E's fleet and encourage our employees to use EVs.

6.3.3 The Internal Fleet Program Forecast Is Reasonable And Should Be Approved

The installation of this new charging infrastructure is imperative for PG&E to electrify and operate its fleet vehicles. In addition to fleet charging that will be available through the EVIP program discussed above in Section 6.3.2, PG&E's Internal Fleet Program forecast includes the capital needed to deploy fleet vehicle charging infrastructure at PG&E locations. Costs for procurement of vehicles are separately forecast in the Transportation and Aviation Services chapter.²⁷⁰³ TURN disputes the capital for the charging stations necessary to charge PG&E's fleet vehicles, but neither TURN, nor any other party, disputes the capital requested for the purchase of the EVs that these charging stations will support.

TURN opposes PG&E's Internal Fleet Program, arguing that the Commission has not previously approved the program and has not conducted a cost-benefit analysis.²⁷⁰⁴ But in PG&E's 2020 GRC, the Commission authorized PG&E's request for employee and fleet EV charging infrastructure without a detailed cost benefit analysis.²⁷⁰⁵ PG&E's 2023 testimony explains that this is largely a continuation of ongoing EV infrastructure deployment and that the forecasted increase in 2023 is due to its plans to install charging infrastructure to support the electrification of 1,048 PG&E fleet vehicles.²⁷⁰⁶ At the time of PG&E's 2020 GRC, the Internal Fleet Electrification program was not differentiated as a distinct or named program

²⁷⁰³ PG&E-07, Ch. 2 Transportation and Aviation Services.

²⁷⁰⁴ TURN-15, p. 8, lines 16-17.

²⁷⁰⁵ D.20-12-005, p. 401, COL 66.

²⁷⁰⁶ PG&E-06-E, p. 2-24, lines 1-5; PG&E-19-E, p. 2-10, lines 21-25.

separate from PG&E's EV Station Infrastructure program, and therefore not previously approved.²⁷⁰⁷ The activities currently performed by the Internal Fleet Program were, at that time, conducted on a reduced scale. The Internal Fleet Program aligns with our commitment to reach net zero greenhouse gas emissions by 2040 and to electrify our vehicle fleet in alignment with the Advanced Clean Fleets Rule (currently in development at the California Air Resources Board (CARB) and expected to be voted on by CARB in early 2023).²⁷⁰⁸

6.4 Pricing Products and Income Qualified Programs

Pricing Products' activities primarily support rate programs, new rates, rate structure changes and rate transitions. Income Qualified Programs funds program activities supporting customers' physical and financial health and safety (such as Cooling Centers), maintains the LIHEAP portal, and supports our expanded work with Disadvantaged Communities and Community-Based Organizations. PG&E's TY 2023 expense forecast, as reflected in opening testimony, is \$22.853 million. PG&E's TY 2023 forecast in the JCE is \$23.852 million.²⁷⁰⁹ PG&E's forecast includes work tracked in two MWCs: MWC EZ, Manage Various Customer Care Processes; and MWC GM, Manage Energy Efficiency Non-Balancing Account. PG&E's expense forecast for these two programs is uncontested. See Appendix A.

6.5 Contact Centers, Customer Technology, and Digital Strategy

Contact Center Operations provides support to PG&E's ten million customers for emergencies and payment inquiries, as well as energy-related services and programs. PG&E's forecast also encompasses the management of core digital systems and platforms such as PGE.com and platforms used to notify customers via text, email, and phone. PG&E's TY 2023

²⁷⁰⁷ PG&E-19-E, p. 2-13, lines 4-7.

²⁷⁰⁸ CA Air Resource Board's Advanced Clean Fleets Proposed Draft Regulation Language: High Priority and Federal Fleet Requirements (May 2, 2022), https://ww2.arb.ca.gov/sites/default/files/2022-04/220502draftpf_ADA.pdf (as of Oct. 26, 2022).

²⁷⁰⁹ PG&E-64, p. 3-4, Table 3A-1, lines 140 and 141.

expense forecast as reflected in opening testimony is \$67.528 million.²⁷¹⁰ PG&E's TY 2023 forecast in the JCE is \$67.970 million.²⁷¹¹ PG&E's forecast includes work tracked in two MWCs: MWC EZ, Manage Various Customer Care Processes; and MWC DK, Manage Customer Inquiries. PG&E's expense forecast is uncontested. See Appendix A.

6.6 Customer Service Offices

PG&E's 65 Customer Service Offices (CSOs) provide customers with in-person customer services, most notably the processing of payments.²⁷¹² CSOs received and processed approximately 2.6 million payments in 2019.²⁷¹³ PG&E's TY 2023 expense forecast as reflected in rebuttal testimony is \$17.991 million.²⁷¹⁴ PG&E's TY 2023 forecast in the JCE is \$18.128 million.²⁷¹⁵ TURN disputes PG&E's forecast and proposes a reduction of \$11.195 million.

PG&E's capital expenditures forecast as reflected in rebuttal testimony is \$0.1 million each year, 2021 through 2023. Capital expenditures forecast in the JCE are \$1.03 million in 2021, \$1.16 million in 2022, and \$1.21 million in 2023, \$1.21 million in 2024, \$1.2 million in 2025, and \$1.18 million in 2026.²⁷¹⁶ PG&E's capital work is tracked in MWC 21, Miscellaneous Capital and is uncontested. See Appendix A.

In April 2022, PG&E filed Application 22-04-016 (CSO Application) proposing to permanently close all of its CSOs. PG&E's analysis of customer payments during the pandemic

²⁷¹⁰ PG&E-06-E, p. 4-53, Table 4-37, line 9.

²⁷¹¹ PG&E-64, p. 3-4, Table 3A-1, lines 140 and 141.

²⁷¹² A.22-04-016, CSO Application, p. 2 (Apr. 28, 2022).

²⁷¹³ The 2019 information is the most recent year with complete data due to the temporary closure of all PG&E's CSOs in March 2020 out of concern for the health and safety of its employees and customers in response to the COVID-19 pandemic.

²⁷¹⁴ PG&E-19-E, p. 5-3, Table 5-1, line 4.

²⁷¹⁵ PG&E-64, p. 3-4, Table 3A-1, lines 144-146.

²⁷¹⁶ PG&E-67, WP-4, Exhibit 6, Ch. 5, MWC 21.

shows that CSO customers successfully transitioned to other payment and assistance channels.²⁷¹⁷ In our CSO Application, we are also proposing utilizing the CSO workforce to perform proactive outreach to help customers pay their bills and enroll in assistance programs such as CARE, FERA, the Arrearage Management Plan, and Medical Baseline. If the Commission does not approve the CSO Application, PG&E may be required to reopen its CSOs to handle in-person transactions. PG&E's 2021 CSO staffing levels are significantly below the levels needed to historically operate the CSOs.

TURN notes that PG&E recorded only \$6.8 million for CSO-related activities in 2021.²⁷¹⁸ However, the CSOs were closed in 2021 and thus the cost information from that year does not reflect the costs that PG&E will incur to operate the CSOs if they are re-opened. Our 2023 expense forecast supports the staffing levels needed to provide effective customer service and support at its 65 CSOs if our proposal to close the CSOs is denied. PG&E's forecast is based, in part, on the need to hire new Customer Service Representatives (CSRs) to replace those who left through attrition while the offices temporarily had to close due to the COVID-19 pandemic. TURN's recommendation to replace PG&E's 2023 forecast with 2021 recorded costs would provide insufficient funding for PG&E to adequately staff its CSOs if they reopen.

In addition, as described in the Memorandum of Understanding signed between and among PG&E, TURN, Cal Advocates, and the Center for Accessible Technology in the CSO Application, PG&E would submit a Tier 2 advice letter within 60 days of the issuance of the Commission's decisions approving PG&E's 2023 GRC and its CSO Closure and Transformation Proposal that details: (1) the proposed reduction in the adopted electric and gas distribution revenue requirements effective January 1, 2024, and (2) the savings to be returned to customers that were realized from the date of the CSO closures through December 31, 2023.²⁷¹⁹ Without

²⁷¹⁷ A.22-04-016, CSO Application, p. 2 (Apr. 28, 2022).

²⁷¹⁸ TURN-15, p. 9, line 2 to p. 11, line 8.

²⁷¹⁹ TURN-609.

any evidence or reasoning, TURN expresses a lack of confidence as to whether the savings calculated by PG&E would be accurate. However, TURN is a party to the Memorandum of Understanding which expressly contemplated this very process.²⁷²⁰

For the reasons explained above, the Commission should reject TURN's proposal and approve PG&E's expense forecast for its 65 CSOs. If the Commission later approves PG&E's request to close its 65 CSOs, the refund mechanism to which TURN and other parties stipulated and detailed in the Memorandum of Understanding in the CSO Application will effectuate the return of any cost savings to customers.

6.7 Billing, Revenue And Credit

PG&E's expense forecast supports billing, credit and revenue activities that enable PG&E to render timely bills, collect payments from customers, report revenue, and allow PG&E to quickly respond to customers' interest in new products and services. PG&E's TY 2023 expense forecast is \$73.516 million.²⁷²¹ PG&E's TY 2023 forecast in the JCE with escalation is \$75.874 million.²⁷²² PG&E's forecast includes work tracked in five MWCs: MWC AR, Read and Investigate Meters; MWC EZ, Manage Various Customer Care Processes; MWC IS, Bill Customers; MWC IT, Manage Credit; and MWC IU, Collect Revenue. PG&E's expense forecast is uncontested. See Appendix A.

PG&E capital expenditures forecast is \$4.0 million in 2021 and \$0 from 2022-2026.²⁷²³ Capital expenditures forecast in the JCE are \$4.122 million in 2021.²⁷²⁴ PG&E's capital forecast is tracked in MWC 21, Miscellaneous Capital, and is uncontested. See Appendix A.

²⁷²⁰ TURN-609.

²⁷²¹ PG&E-06-E, p. 616, Table 6-4, line 6.

²⁷²² PG&E-64, p. 3-4, Table 3A-1, lines 147-151.

²⁷²³ PG&E-06-E, p. 6-16, Table 6-5, line 2.

²⁷²⁴ PG&E-64, p. 3-16, Table 3B-3, line 99.

6.8 Metering Services and Engineering

PG&E's metering services and engineering programs support meter maintenance and the network optimization necessary to provide for the timely and accurate recording, collection, and delivery of customer billing data. It will also allow for necessary quality assurance testing on meters, meter warranty management, and engineering analysis.

PG&E's TY 2023 expense forecast is \$8.024 million.²⁷²⁵ PG&E's JCE forecast is \$8.091 million.²⁷²⁶ PG&E's expense forecast is uncontested. See Appendix A.

PG&E's capital expenditures forecast is \$111.702 million in 2021, \$108.515 million in 2022, \$107.329 million in 2023, \$111.440 million in 2024, \$116.028 million in 2025, and \$118.935 million in 2026.²⁷²⁷ Capital expenditures forecast in the JCE are \$116.416 million in 2021, \$120.641 million in 2022, \$121.908 million in 2023, \$125.398 million in 2024, \$128.530 million in 2025, and \$128.816 million in 2026.²⁷²⁸

Although most of the meter service and engineering capital forecast is uncontested, Cal Advocates and TURN propose the following limited reductions for metering services that are needed as part of PG&E's Community Rebuild Program:

²⁷²⁵ PG&E-06-E, p. 7-16, Table 7-3, line 4.

²⁷²⁶ PG&E-64, p. 3-4, Table 3A-1, lines 152-154.

²⁷²⁷ PG&E-19-E, p. 7-7, Table 7-5, line 7 (2024-2026).

²⁷²⁸ PG&E-67, WP-4, Exhibit 6, Ch. 7, MWCs, 05, 21, 25, 74, 3J and 3M.

TABLE 6-3
METERING SERVICES AND ENGINEERING: PG&E’S CAPITAL FORECAST AND PARTIES
RECOMMENDED REDUCTIONS (\$000s)^(a)

Party	2020 Rec.	2021	2022	2023	2024	2025	2026
PG&E	\$116,298	\$111,702	\$108,515	\$107,329	\$111,440	\$116,028	\$118,935
Cal Advocates				\$(529)			
TURN				\$(529)	\$(540)	\$(328)	\$(336)
(a) PG&E-19-E, p. 7-7, Table 7-5, line 7; p. 7-4, Table 7-2, line 7.							

Cal Advocates and TURN propose to remove all costs associated with PG&E’s Community Rebuild Program from PG&E’s forecasts and require PG&E to instead seek approval of these amounts in arrears through a Catastrophic Event Memorandum Account (CEMA) application.²⁷²⁹ The proposal is addressed above in Section 4.23 of this brief.

6.9 Compliance and Regulatory Strategy

PG&E’s Compliance and Regulatory Strategy forecast supports several functions, including regulatory strategy; customer experience and insights; tariff interpretation; risk, compliance, audit; and customer and employee privacy. PG&E’s TY 2023 expense forecast is \$21.352 million.²⁷³⁰ PG&E’s JCE forecast is \$21.864 million.²⁷³¹ Expense work is tracked in two MWCs, one of which, MWC EZ, Manage Various Customer Care Processes, is uncontested. See Appendix A.

The forecast for the contested MWC (*i.e.*, MWC OM) is \$5.375 million which includes labor and employee-related costs to provide supervision and management support, as well as costs for administrative staff working for the Supervisors and Managers.²⁷³² TURN recommends a reduction of \$1.9 million to PG&E’s forecast.

²⁷²⁹ CALPA-09, p. 4, lines 9-13 and TURN-13, p. 8, lines 15-21.

²⁷³⁰ PG&E-06-E, p. 8-17, Table 8-2, line 4.

²⁷³¹ PG&E-64, p. 3-4, Table 3A-1, lines 155-156.

²⁷³² PG&E-06-E, p. 8-12, lines 25-27; PG&E-19, p. 8-3, lines 3-4.

TURN argues that PG&E should not recover office compensation because PG&E is voluntarily not recovering it currently.²⁷³³ While PG&E elected not to seek officer compensation in the 2020 GRC, it did not waive its right to recover officer compensation in future GRCs. Officer compensation is a reasonable cost of service to operate a business, particularly a large business on the scale of PG&E's Customer and Communications organization. The Commission historically and routinely allows utilities to recover the costs of officer compensation. For example, the Commission recently held in SCE's 2021 GRC, that SCE could recover the costs of compensation for utility officers except utility officers who are defined by Rule 240.3b-7 of the Securities Exchange Act, in full compliance with Public Utilities Code Section 706.²⁷³⁴ Consistent with well-established precedent, the Commission should approve PG&E's requested officer compensation in Compliance and Regulatory Strategy as a reasonable operating cost and reject TURN's proposal.

6.10 Gas AMI Module Replacement

PG&E's Gas AMI Module Replacement Project plans for the accelerated replacement of legacy Gas Modules, which are reaching end-of-life over the next several years. PG&E notified the Commission and parties in its 2020 GRC that the Gas Modules had begun to fail.²⁷³⁵ PG&E has been replacing Modules as they fail as part of a corrective maintenance program. Going forward, we are proposing a proactive Replacement Project as part of the system's asset life cycle management to enable a more-efficient, less-costly installation of the next set of Gas Modules.²⁷³⁶ These module replacements are critical to providing utility service to customers. They allow PG&E to efficiently perform a core business function. The modules are

²⁷³³ TURN-15, p. 12, lines 3-4.

²⁷³⁴ D.21-08-036, pp. 418-419. Chief Customer Officer and Senior Vice President Marlene Santos is designated as a Rule 240.3b-7 Officer. PG&E does not seek cost recovery of her salary and benefits in this proceeding.

²⁷³⁵ PG&E-06-E, p. 9-14, lines 3-5.

²⁷³⁶ PG&E-19-E, p. 9-1, lines 21-25.

communications devices attached to gas meters that automatically communicate customer gas usage readings to PG&E's AMI head end and billing systems enabling automated, remote meter reading of the gas meters to bill the Company's over four million gas customers. The modules are integral to a basic function of the utility: to bill customers for their commodity usage.

PG&E's TY 2023 expense forecast as reflected in rebuttal testimony is \$9.437 million. PG&E's JCE forecast is \$9.715 million.²⁷³⁷

PG&E capital expenditures forecast as reflected in rebuttal testimony is \$46.063 million in 2021, \$54.751 million in 2022, \$94.988 million in 2023, \$141.626 million in 2024, \$133.560 million in 2025, and \$110.310 million in 2026. Capital expenditures forecast in the JCE are \$47.469 million in 2021, \$63.573 million in 2022, \$114.948 million in 2023, \$171.631 million in 2024, \$159.768 million in 2025, and \$130.273 million in 2026.²⁷³⁸

Cal Advocates, TURN, and AARP dispute PG&E's expense forecast and propose the below reductions.

TABLE 6-4
GAS AMI MODULE REPLACEMENT: PG&E'S EXPENSE FORECAST AND PARTIES
RECOMMENDED REDUCTIONS (\$000s)^(a)

Party	2020 Rec.	2021	2022	2023
PG&E	\$-	\$-	\$-	\$9,437
Cal Advocates				\$(2,000)
TURN				\$(9,437)
AARP				\$(9,437)
(a) PG&E-19-E, p. 9-28, Table 9-4, line 5; p. 9-5, Table 9-1, line 5.				

²⁷³⁷ PG&E-64, p. 3-4, Table 3A-1, lines 157-160.

²⁷³⁸ PG&E-67, WP-4; PG&E-06-E, p. 9-16, lines 19-25, MWC 2F.

Cal Advocates, TURN, and AARP also dispute PG&E’s capital forecast and propose the following additional reductions.

TABLE 6-5
GAS AMI MODULE REPLACEMENT: PG&E’S CAPITAL FORECAST AND PARTIES
RECOMMENDED REDUCTIONS (\$000s)^(a)

Party	2020 Rec.	2021	2022	2023	2024	2025	2026
PG&E	\$-	\$46,063	\$54,751	\$94,988	\$141,626	\$133,560	\$110,310
Cal Advocates				\$(71,678)			
TURN				\$(94,988)	\$(141,626)	\$(133,560)	\$(110,310)
AARP				\$(93,238)	\$(141,551)	\$(133,485)	\$(110,235)
(a) PG&E-19-E, p. 9-29, Table 9-5, line 3; p. 9-6, Table 9-2, line 3; p. 9-7, Table 9-2, line 6.							

PG&E responds below to these parties’ positions regarding the following issues related to PG&E’s AMI Module Replacement forecasts: (1) proactive replacement is the least cost option; (2) PG&E’s management of the AMI program; (3) the need for proactive replacement; and (4) PG&E’s rate of return.

6.10.1 PG&E’s Proactive Replacement Project Is The Least Cost Option To Replace Critical AMI Equipment

PG&E’s Gas AMI Module Replacement Project provides for the proactive replacement of legacy gas modules to more cost effectively replace these modules. It is less expensive due to economies of scale and shorter travel times, as well as better customer service to proactively replace modules before they fail than to make ad hoc truck rolls to each location to repair and/or replace the modules at their respective times of failure. There is no dispute that the Gas AMI modules have begun to fail and will be reaching end-of-life over the next few years. Our economic analysis over a 15-year study period has shown the net present value (NPV) of proactively replacing Gas AMI Modules is (-\$936) million (of capital and expense), compared to the projected (-\$963) million if we continue replacing individual modules as they fail.²⁷³⁹ PG&E estimates that without the proactive replacement of failing Gas AMI modules, costs

²⁷³⁹ PG&E-06-E, p. 9-6, Table 9-1; PG&E-19-E, WP 9-2.

would increase by approximately \$400 million in capital expenditures above the amounts forecast for the maintenance program currently forecasted in the GRC.²⁷⁴⁰

While an additional \$400 million in capital expenditures for corrective maintenance is less than the \$480.5 million in capital expenditures proposed for proactive replacement in this GRC, this \$400 million only reflects costs expected in the 2023 GRC period. When costs over a longer period are considered, our proposed proactive replacement is both more cost-effective and better customer service.²⁷⁴¹ Once the Gas AMI Module Replacement Project is complete, and the remaining legacy modules have been replaced, subsequently incurred corrective maintenance costs will be lower, resulting in long-term savings. As discussed above, PG&E's current corrective maintenance volumes assume that PG&E would initiate proactive replacement in 2023. Alternatively, if PG&E's proposal is denied, the Commission should authorize a commensurate \$400.1 million increase in corrective maintenance work.²⁷⁴² PG&E's proactive replacement project is a concurrent and complementary replacement effort that will enable a more efficient, cost-effective installation of replacement modules, compared to corrective maintenance, thereby saving customers money and providing a better, more proactive customer experience.

6.10.2 PG&E Has Prudently Managed Its Gas AMI Program Since Inception

Cal Advocates and TURN suggest PG&E did not act prudently and assert that this alleged imprudent conduct justifies a disallowance. Cal Advocates and TURN base their recommended disallowances solely on the fact that the modules that PG&E installed are not going to last the originally anticipated 20 years. They make this argument with no facts or

²⁷⁴⁰ PG&E-19-E, p. 9-24, lines 5-19.

²⁷⁴¹ PG&E-06-E, p. 9-12, lines 17-22; PG&E-06, WP 9-10 and WP 9-13; Tr. Vol 11, 2096:10-23, AARP/Console; Tr. Vol 11, 2099:5-14, AARP/Console.

²⁷⁴² PG&E-19-E, p. 9-24, lines 5-19.

evidence to support their assertions.²⁷⁴³ In fact, PG&E has acted reasonably and prudently throughout these modules' life cycle, and Cal Advocates and TURN forget that AMI was a new technology when California, led by PG&E, initiated it. Beginning with the original technology selection and deployment, and continuing through ongoing maintenance, supplier relations, and end-of-life replacement planning, PG&E has provided strong oversight and performed active due diligence, as reflected in PG&E's securing a 20-year warranty, raising the battery-failure issue in its 2020 GRC, and managing the issue throughout to minimize impacts to customers. While PG&E has the burden of proof to show the reasonableness of its request, the Commission has held that if other parties to a proceeding propose a different result, "they too have a 'burden of going forward' to produce evidence to support their position and raise a reasonable doubt as to the utility's request."²⁷⁴⁴ Cal Advocates and TURN have not done so here.

PG&E was an early adopter of AMI technology.²⁷⁴⁵ The scale of PG&E's deployment at the time, and the relative lack of track record for these technologies, introduced an inherent level of risk that PG&E worked diligently and prudently to mitigate. No other utility had attempted to deploy AMI to the same extent.²⁷⁴⁶ When the Commission first approved PG&E's AMI deployment, it noted that:

Although PG&E expects the system to remain in service for 20 years, only time will tell whether there will be significant unforeseen developments—good or bad—that may lead to an earlier or later replacement of the AMI system.²⁷⁴⁷

In recognition of the possibility of unforeseen developments, PG&E took appropriate measures to thoroughly vet the proposed project. While the Commission previously has denied recovery of costs relating to defective equipment where there is an insufficient record to make a

²⁷⁴³ TURN-15; CALPA-05, CALPA-09.

²⁷⁴⁴ D. 21-08-036, p. 101 (citations omitted).

²⁷⁴⁵ PG&E-06-E, p. 9-8, lines 12-13.

²⁷⁴⁶ PG&E-19-E, p. 9-15, lines 3-4.

²⁷⁴⁷ D.06-07-027, pp. 27-28.

finding that a utility acted prudently,²⁷⁴⁸ this is not the case here. The Commission reviewed PG&E's SmartMeter™ deployment and found the program reasonable.²⁷⁴⁹ PG&E pursued AMI at the Commission's direction, and with its subsequent approval.²⁷⁵⁰

PG&E selected its AMI vendors and products through a thorough and extensive solicitation process involving a total of 77 proposals, with at least five specifically related to gas modules.²⁷⁵¹ PG&E required these vendors to demonstrate that their proposed technologies were reliable, tested, and could be deployed at the large scale PG&E needed.²⁷⁵² The solicitation process considered various risk criteria, including product maturity and proven track record.²⁷⁵³

PG&E conducted significant testing and evaluation in the AMI product and vendor selection process, including detailed product reviews with each of the vendors involved.²⁷⁵⁴ And PG&E personnel made many visits to the vendors' product manufacturing sites to evaluate quality assurance procedures.²⁷⁵⁵ Moreover, PG&E independently evaluated studies of the estimated module battery life and overall expected useful product life that prospective suppliers provided it before PG&E moved forward with its AMI program.²⁷⁵⁶

²⁷⁴⁸ D. 22-06-032, pp. 30-31.

²⁷⁴⁹ D. 22-06-032, pp. 30-31.

²⁷⁵⁰ D. 06-07-027, p. 65 COL 1: "PG&E met its burden of proof and, with the other parties, presented sufficient credible evidence to find that it is reasonable to authorize PG&E to deploy the AMI project as modified in this decision."

²⁷⁵¹ PG&E-19-E, p. 9-16, lines 3-4; TURN-407, PG&E Response to TURN_240, Q009.

²⁷⁵² PG&E-19-E, p. 9-16, lines 4-7.

²⁷⁵³ PG&E-19-E, p. 9-16, lines 7-10.

²⁷⁵⁴ PG&E-19-E, p. 9-16, lines 27-28.

²⁷⁵⁵ PG&E-19-E, p. 9-16, lines 30-31.

²⁷⁵⁶ PG&E-19-E, p. 9-16, lines 31-32.

During its AMI deployment, PG&E negotiated and secured a 20-year warranty from its Gas AMI Module supplier to ensure support for its product claims.²⁷⁵⁷ It was our understanding at the time that it was the longest warranty ever secured in the industry.²⁷⁵⁸ And the 20-year warranty certainly was significantly longer than the typical one-to three-year standard warranties offered to most utilities at the time.²⁷⁵⁹ The warranty PG&E secured was akin to a prorated “tire tread” warranty. Just as a buyer would not receive full value for a set of tires after driving on them for tens of thousands of miles, PG&E’s supplier warranty was not designed to return the full cost of the modules after already providing years of effective service. PG&E receives a residual warranty value that represents the remaining years of the projected 20-year warranty life after a module battery fails.²⁷⁶⁰ The warranty recognized the years of value that the Modules provided in service up to the point of failure, providing PG&E’s supplier with credit for the time that the Module and battery operated; and provided remedies to PG&E based on a pro rata remaining life basis, providing PG&E with a remedy for the remainder of the 20-year warranty life.²⁷⁶¹ The warranty secured represented a reasonable way to manage and appropriately assign the risks of gas module failure for this then-new technology.

Once it was established that the modules would fail prematurely, we took action to protect our customers. This included regular monitoring and assessment of early Gas Module failure rates and studying failure rates. PG&E retained third-party consulting experts to perform engineering failure rate analyses. By applying a statistical model, PG&E’s expert consultant was able to forecast how long PG&E’s remaining installed legacy Gas AMI standard range Modules

²⁷⁵⁷ PG&E-06-E, p. 9-10, lines 20-23; PG&E-19-E, p. 9-17, lines 2-3.

²⁷⁵⁸ PG&E-19-E, p. 9-17, lines 3-4.

²⁷⁵⁹ PG&E-19-E, p. 9-17, lines 5-7.

²⁷⁶⁰ PG&E-06-E, p. 9-4, fn. 8; PG&E-19-E, p. 9-17, lines 12-15.

²⁷⁶¹ PG&E-06-E, p. 9-8, lines 13-14; PG&E-19-E, p. 9-17, lines 10-12.

would last,²⁷⁶² enabling the Company to compare the revenue requirements for the corrective maintenance and proactive replacement alternatives,²⁷⁶³ and forecast when to begin a proactive, programmatic replacement to minimize the costs to customers.²⁷⁶⁴ PG&E also expanded quality assurance product testing, conducted field-based root cause analysis, performed corrective maintenance to replace failed Modules, and monitored the AMI technology marketplace.²⁷⁶⁵

Since the failure rate has been higher and earlier than anticipated at the time of the AMI rollout, PG&E has worked with its supplier to establish a warranty returns program through which it has returned Gas Modules to the supplier for failures attributable to the supplier's product. PG&E has applied warranty credits to partially offset the incremental costs for purchasing and replacing the Modules.²⁷⁶⁶ In addition, PG&E's supplier is proactively providing PG&E with replacement units for extended range Gas Modules at no charge to PG&E.²⁷⁶⁷ PG&E has included the financial benefits of the warranty program in its 2023 GRC forecast to reduce Gas Module replacement costs.²⁷⁶⁸ Additionally, customers have benefited from the warranty program in the 2020 GRC period as PG&E had forecasted and taken warranty credits from the supplier.²⁷⁶⁹

PG&E has created a Project Management Office (PMO) to coordinate and plan the Gas AMI Proactive Replacement Project. The PMO allows for dedicated and efficient oversight of

²⁷⁶² PG&E-06-E, p. 9-4, lines 13-16; PG&E-19-E, p. 9-18, lines 17-19.

²⁷⁶³ PG&E-19-E, p. 9-18, lines 20-23.

²⁷⁶⁴ PG&E-06-E, p. 9-5, lines 3-5.

²⁷⁶⁵ PG&E-19-E, p. 9-18, lines. 7-10.

²⁷⁶⁶ PG&E-19-E, p. 9-19, lines. 3-5.

²⁷⁶⁷ PG&E-19-E, p. 9-19, lines. 7-9.

²⁷⁶⁸ PG&E-19-E, p. 9-19, lines 11-13.

²⁷⁶⁹ PG&E-06-E, WP 9-12, Gas Module Warranty Returns; PG&E-19-E, p. 9-19, lines 13-15.

implementation activities. Cal Advocates recommends a \$2 million reduction in expense for the PMO. Cal Advocates cites to D.06-07-027, which authorized PG&E to implement a project management structure for its original AMI rollout, arguing full time employee (FTE) costs are embedded in rates.²⁷⁷⁰ However, the original AMI project was completed in 2014, and has since been dissolved.²⁷⁷¹ New FTEs for the PMO are incremental positions to oversee the Gas AMI Module replacement program and were not requested in PG&E's 2020 GRC forecast.²⁷⁷² Cal Advocates further argues PG&E did not support its forecast for consulting costs and they should not be categorized as labor costs.²⁷⁷³ PG&E informed Cal Advocates at the time that it had not yet selected its consulting vendors. Consultant costs for the PMO are supported through detailed descriptions of the nature and importance of these services. The categorization as labor or non-labor does not impact their recoverability, as they are necessary for the successful completion of the Gas AMI Module Replacement Project.

PG&E, now and throughout the deployment of its AMI program, has worked to ensure customers are protected against risk and that the early end-of-life replacement has been conducted in the least cost manner available after considering alternative options. TURN's and Cal Advocates' unsupported assertions are contrary to the undisputed evidence in this proceeding and should be rejected.

6.10.3 If Proactive Replacement Is Denied, Corrective Maintenance Costs Will Increase

As discussed above in Section 6.10.1, PG&E has determined that including a proactive program for replacement of Gas Modules, rather than solely performing corrective maintenance starting in 2023, is most cost-effective. Our economic analysis has shown the net present value

²⁷⁷⁰ CALPA-09, p. 22, lines 15-17.

²⁷⁷¹ PG&E-19-E, p. 9-12, lines 25-27.

²⁷⁷² PG&E-19-E, p. 9-12, lines 21-22.

²⁷⁷³ CALPA-09, p. 20, lines 15-16.

of proactively replacing Gas AMI Modules is -\$936 million, compared to the projected -\$963 million if the Company continues corrective maintenance.²⁷⁷⁴

AARP argues that there is variation in PG&E's projected costs and benefits and thus the AMI Gas Module Replacement project may not be cost-effective.²⁷⁷⁵ AARP further argues that because PG&E has not yet completed its solicitation, the costs of proactive replacement may be higher than estimated, particularly due to inflation. But AARP fails to mention that if costs escalate at a rate higher than forecasted, those cost increases will affect costs in both the proactive replacement *and* the status quo corrective maintenance scenarios. Furthermore, PG&E's vendor proposals are generally in line with PG&E's forecasts for the replacement Project. In response to AARP's questioning during evidentiary hearings, PG&E witness David Console confirmed that "given that sensitivity of cost... a variation of that would still indicate that having a proactive replacement project is still the least cost approach to replacing modules that are reaching end of life."²⁷⁷⁶

PG&E estimates that if the proactive Gas AMI Module Replacement Project is not approved, Gas Module corrective maintenance costs would increase by approximately \$400 million above the amounts currently forecasted in the 2023-2026 GRC period.²⁷⁷⁷ PG&E estimated the current corrective maintenance volumes based on the assumption that PG&E would initiate proactive replacement in 2023.²⁷⁷⁸ Denying the proactive replacement proposal would necessitate a corresponding increase in corrective maintenance work.²⁷⁷⁹ When costs over a 15-year period are considered, PG&E's proposed proactive replacement is the most cost-

²⁷⁷⁴ PG&E-06-E, p. 9-6, Table 9-1.

²⁷⁷⁵ AARP-01, p. 55, lines 9-17.

²⁷⁷⁶ Tr. Vol. 11, 2101:3-9, AARP/Console.

²⁷⁷⁷ PG&E-19-E, p. 9-24, lines 8-11.

²⁷⁷⁸ PG&E-06-E, Ch. 9.

²⁷⁷⁹ PG&E-19-E, p. 9-24, lines 8-11; PG&E-06, WP 9-10.

effective way to replace Gas Modules at the lowest cost to ratepayers.²⁷⁸⁰ Once the Gas AMI Module Replacement Project is complete, subsequent corrective maintenance costs will be considerably lower, as all of the remaining legacy modules will at that point have been replaced.

AARP also ignores that proactively replacing these Gas Modules before they fail is far and away a better customer experience. By replacing the modules on geographically targeted basis, it is far less likely customer meter-reading will be disrupted.²⁷⁸¹ AARP also ignores the benefit that proactive replacement serves by hedging against spikes in module failures during this GRC period. Replacing gas modules after failure would substantially increase the corrective maintenance work required and create a backlog of failed modules pending replacement.²⁷⁸² If the Commission does not approve the proactive Gas AMI Module Replacement Project, PG&E instead requests approval for \$400.1 million²⁷⁸³ above the amounts currently forecasted in the GRC to fund corrective maintenance costs.²⁷⁸⁴

6.10.4 PG&E Should Earn A Full Rate Of Return On Early Module Retirements

TURN argues that the requested early replacements of gas modules are not used and useful and have not been adequately justified for inclusion in rate base. TURN essentially proposes that PG&E's shareholders pay for all costs associated with the Gas AMI Proactive Replacement Project as well as the cost of replacing any gas modules that have failed prematurely. TURN also suggests the Commission reduce the cost of capital on PG&E's investments in the Gas AMI Modules by imposing a reduced return on equity for those

²⁷⁸⁰ PG&E-06-E, WP 9-10 and WP 9-13; Tr. Vol. 11, 2096:10-23, AARP/Console; Tr. Vol. 11, 2099:5-14, AARP/Console.

²⁷⁸¹ PG&E-19-E, p. 9-25, lines 21-24.

²⁷⁸² PG&E-19-E, p. 9-25, lines 24-28.

²⁷⁸³ The incremental costs for the Status Quo scenario (e.g., continuing with corrective maintenance instead of proactive replacement) are detailed in PG&E-19, WP 9-1.

²⁷⁸⁴ PG&E-19-E, p. 9-24, line 30 to p. 9-25, line 3.

investments.²⁷⁸⁵ Cal Advocates recommends that shareholders pay the routine and reasonable costs of providing utility service for Gas AMI modules two-thirds of the forecast capital costs associated with the replacement of defective gas AMI modules, or about \$388 million over the period 2021-2026.²⁷⁸⁶

TURN's and Cal Advocates' punitive recommendations are unwarranted. Costs for the Gas AMI Proactive Replacement Program are reasonable and necessary to provide reliable utility service as described in PG&E's opening and rebuttal testimony.²⁷⁸⁷ As explained in Section 6.10.2 above, PG&E has administered the Gas AMI program prudently and diligently, including proactively addressing accelerated life cycle replacement when the modules began failing. TURN's suggestion that the Commission should disallow PG&E's costs for its prudently incurred gas AMI program²⁷⁸⁸ is contrary to longstanding regulatory principles that a utility be given a reasonable opportunity to earn a fair return when the utility's conduct has been prudent and reasonable.

TURN's asymmetric and punitive proposal penalize utilities for equipment failure despite their acting prudently and reasonably, but not offer any benefit to utilities if equipment performs better than expected. Under TURN's one-sided proposal, the utility would no longer have a reasonable opportunity to earn its return based on prudent management, and as a result the return would have to be set at a higher level so that sound management could achieve a "net" return sufficient to attract capital, to account for those circumstances where things go unexpectedly.

The effect of TURN's proposal would be to greatly complicate ratemaking, increase investor risk, and confuse cost of capital proceedings (since a higher rate of return would have to be established to attract capital than otherwise). By deviating from original cost of service

²⁷⁸⁵ TURN-13, p. 13, lines 10-15.

²⁷⁸⁶ CALPA-05, p. 14, lines 13-17.

²⁷⁸⁷ PG&E-06-E, p. 9-6, lines 3-7; PG&E-19, p. 9-23, lines 12-14.

²⁷⁸⁸ TURN-13, p. 12, lines 16-20.

ratemaking and making California ratemaking even more complex than it already is, TURN's proposal would represent a significant step backward for California and ultimately increase costs for California consumers. The Commission should follow established precedent and practice and decline to consider TURN's and Cal Advocates' proposals.

6.11 Customer Care Technology Projects

Through the Customer Care Technology Investments program, PG&E proposes investments that are critical to serving over six million customers in areas of billing, customer service, and customer data management. Ongoing investments are targeted to meet the growing expectations for on-demand customer access to information and self-service capabilities; customer data security, reporting, and analytics; customer relationship management; and multi-channel billing and payment services. The expense activities PG&E plans include ongoing maintenance, operations, and repair for PG&E's applications, systems, and infrastructure technology solutions supporting Customer Care. The capital activities that PG&E plans include costs to design, develop and enhance applications, systems, and infrastructure technology solutions. PG&E is also proposing to upgrade its current billing system in order to enable quicker rate change responsiveness for new rate programs, efficient maintenance of existing rates programs, better billing timeliness and accuracy, and provide future access to additional customer service features.

PG&E's TY 2023 expense forecast as reflected in rebuttal testimony is \$21.446 million. PG&E's JCE forecast is \$22.540 million.²⁷⁸⁹

PG&E's capital expenditures forecast as reflected in rebuttal testimony is \$35.68 million in 2021, \$77.7 million in 2022, \$75.6 million in 2023, \$58.5 million in 2024, \$27.0 million in 2025, and \$27.0 million in 2026. Capital expenditures forecasts in the JCE are \$36.769 million

²⁷⁸⁹ PG&E-64, p. 3-4, Table 3A-1, line 161.

in 2021, \$90.220 million in 2022, \$91.486 million in 2023, \$70.894 million in 2024, \$32.298 million in 2025, and \$31.886 million in 2026.²⁷⁹⁰

Cal Advocates and TURN dispute PG&E's expense forecast and propose the following reductions.

TABLE 6-6
CUSTOMER CARE TECHNOLOGY: PG&E'S EXPENSE FORECAST AND PARTIES
RECOMMENDED REDUCTIONS (\$000s)^(a)

Party	2020 Rec.	2021	2022	2023
PG&E	\$20,362	\$16,071	\$18,808	\$21,446
Cal Advocates				\$(8,446)
TURN				\$(2,600)
(a) PG&E-19-E, p. 10-19, Table 10-4, line 2; p. 10-3, Table 10-1, line 2.				

TURN disputes PG&E's capital forecast and propose the following reductions.

TABLE 6-7
CUSTOMER CARE TECHNOLOGY: PG&E'S CAPITAL FORECAST AND PARTIES
RECOMMENDED REDUCTIONS (\$000s)^(A)

Party	2020 Rec.	2021	2022	2023	2024	2025	2026
PG&E	\$14,968	\$35,680	\$77,700	\$75,600	\$58,500	\$27,000	\$27,000
TURN				\$(48,300)	\$(44,200)		
(a) PG&E-19-E, p. 10-19, Table 10-5, line 2; p. 10-4, Table 10-2, line 2.							

Cal Advocates recommends a reduction to PG&E's expense forecast of \$8.446 million.²⁷⁹¹ Cal Advocates asserts that PG&E's MWC JV forecast for 2023 is overstated because it includes costs already embedded in rates.²⁷⁹²

TURN recommends a reduction to PG&E's expense forecast of \$2.6 million. TURN also recommends capital reductions of \$48.3 million in 2023 and \$44.2 million in 2024 for MWC 2F.

²⁷⁹⁰ PG&E-67, WP-4, Exhibit 6, Ch. 10, MWCs 21, 2F and 3M.

²⁷⁹¹ PG&E-19-E, p. 10-3, Table 10-1, line 2.

²⁷⁹² CALPA-09, p. 28, lines 20-22.

TURN recommends that PG&E remove the Billing System Upgrade Project from this GRC and file a separate application.²⁷⁹³

In response to these proposed reductions, below we discuss how: (1) the evidence in this proceeding supports PG&E's billing system upgrade; (2) the billing system upgrade costs are not embedded in rates; (3) PG&E is properly capitalizing cloud computing costs; and (4) the billing system upgrade is critical to address the significant changes in California's rate and regulatory landscape.

6.11.1 PG&E's Forecast For The Billing System Upgrade Is Supported Given The Current Project Stage

PG&E derived its estimate for the Billing System Upgrade Project from its Project Estimating Tool (PET).²⁷⁹⁴ This is PG&E's standard process.²⁷⁹⁵ The PET is the primary tool that the Company's technology planners use to document forecast assumptions and develop cost estimates for IT programs and projects. PG&E included the PET for its Billing System Upgrade Project in an attachment to its rebuttal testimony.²⁷⁹⁶ The PET's output is based on assumptions of project size, complexity, user, and customer impact, among other things, providing ample detail to support a critically necessary technology upgrade.²⁷⁹⁷

TURN argues that PG&E's submission did not provide details on timelines, implementation plans, or resource estimates, but for a project of this size and complexity, a detailed implementation plan is premature.²⁷⁹⁸ PG&E thoroughly and adequately supports its

²⁷⁹³ TURN-15, p. 15, lines 1-2.

²⁷⁹⁴ The PET is described in more detail in Exhibit PG&E-07, p. 8-64, line 4 to p. 8-66, line 24.

²⁷⁹⁵ PG&E-19-E, p. 10-8, line 10-14.

²⁷⁹⁶ PG&E-19-E, Ch. 10, Attachment A.

²⁷⁹⁷ PG&E-19-E, p. 10-11, lines 24-27.

²⁷⁹⁸ TURN-15, p. 15, lines 4-14.

forecast in its testimony²⁷⁹⁹ and workpapers; a detailed implementation plan should not be necessary to support the project.²⁸⁰⁰ These sources contain sufficient information to support PG&E's forecast and for the Commission to make an informed decision.

PG&E typically develops implementation plans toward the end of a project's testing phase, as the project shifts focus from testing system functionality to system performance and data migration activities in preparation to the switch to the new billing system.²⁸⁰¹ It is not unusual for the Commission to approve a technology project in the early stages of a project, and TURN's objections calling for detailed implementation planning is a red herring.²⁸⁰²

6.11.2 Projects Related To The Current Billing System Are Not Embedded In Rates

The current billing system maintenance and operations costs in the forecast for the Billing System Upgrade Project are not embedded in rates. The proposed upgrade is a distinct project. Cal Advocates erroneously argues that the Billing System Upgrade Project is not new, and costs are already in rates for its test year forecast. Cal Advocates points to PG&E's 2020 GRC, where funding was authorized to upgrade IT systems and software applications that are at risk of becoming unstable due to age and other technical factors.²⁸⁰³ To arrive at this conclusion, Cal Advocates mistakenly relies on responses to data requests it propounded that were not designed to elicit responses that would inform whether costs were embedded in historical rates.²⁸⁰⁴ Cal Advocates' data request sought total costs of the existing billing system, utilization plans for the existing billing system during the upgrade, and cost benefit

²⁷⁹⁹ PG&E-06-E, Ch. 10; PG&E-19-E, Ch. 10.

²⁸⁰⁰ PG&E-06-E, WP 10-12 to WP 10-104; PG&E-19-E, Attachment A.

²⁸⁰¹ PG&E-19-E, p. 10-11, lines 14-18.

²⁸⁰² PG&E-19-E, p. 10-11, lines 18-19.

²⁸⁰³ D.20-12-005, p. 145.

²⁸⁰⁴ PG&E-19, PG&E's response to Data Request CalAdvocates_0233-Q02, dated 2/2/22, pp. AppA-15 to AppA-17.

analysis for the upgrade. It is standard practice for concurrent operation of two systems while data migration occurs during the switch to a new system.²⁸⁰⁵ Further, while ongoing maintenance and operational costs are not tracked at a system level, the nature and urgent need for the Billing System Upgrade Project is such that prudent system upgrades must be implemented to the old system as the Project begins.

Regardless, the PET that PG&E provided in its rebuttal testimony shows that forecasts for the Billing System Upgrade Project do not include maintenance and operations costs already in rates.²⁸⁰⁶ PG&E's workpapers further summarizes some of these data elements, showing that the Project start date and investment years are covered by this GRC period.²⁸⁰⁷ In short, PG&E has provided ample documentation to demonstrate that the Billing System Upgrade Project is a new project.

6.11.3 PG&E Has Properly Capitalized Cloud Computing Costs

The Commission has historically determined capitalizable internal-use software costs are recorded as utility plant assets and included in rate base.²⁸⁰⁸ PG&E has followed this accounting guidance in its forecast for cloud-based programs.²⁸⁰⁹ PG&E's capital forecast for cloud computing includes upfront costs to integrate with on-premise software, coding, configuration and customization.²⁸¹⁰ Forecast expense includes service fees and other non-capital costs.²⁸¹¹

²⁸⁰⁵ PG&E-19-E, p. 10-8, lines 1-5.

²⁸⁰⁶ PG&E-19-E, p. 10-AtchA-11.

²⁸⁰⁷ PG&E-06-E, WP 10-12 to WP 10-15.

²⁸⁰⁸ PG&E-19-E, p. 10-17, lines 10-15.

²⁸⁰⁹ PG&E-19-E, p. 10-17, lines 18-19.

²⁸¹⁰ PG&E-19-E, p. 10-17, lines 21-22.

²⁸¹¹ PG&E-19-E, p. 10-17, lines 23-24.

TURN argues the Commission has not decided if it is appropriate to treat expenses related to cloud-based solutions as capital expenditures, and whether it is “appropriate to ratebase these expenditures.”²⁸¹² TURN is incorrect. The Commission confers rate base treatment for cloud-based solutions in line with the current accounting practices as provided in the Financial Accounting Standards Board and FERC guidance.²⁸¹³

6.11.4 The Billing System Upgrade Is Essential To Responsive Rate Change

As California increasingly addresses its climate policy and reliability goals through the adoption of new decarbonization technologies and load shifting approaches, rate structures will continue to increase in complexity and require new and/or improved dynamic rate approaches. There is a crucial and urgent need for the Project to support new rate programs and rate structure changes, as well as to address IT system limitations brought on by product obsolescence and a lack of application support. TURN argues PG&E’s showing does not contain the information necessary for the Commission to determine whether the Billing System Upgrade project is reasonable.²⁸¹⁴ PG&E has provided ample support for its forecasts, consistent with a project in this stage of implementation. Given the imperatives of climate change and grid reliability, the essential customer billing function the system performs for the business, and the necessity of avoiding unnecessary technology risks, PG&E submitted this request, in its initial stages, within this GRC cycle.²⁸¹⁵

California continues to address climate policy goals through the pursuit of 100 percent renewable power. For example, Senate Bill 100 outlines the State’s commitment to a carbon-

²⁸¹² TURN-15, p. 14, lines 16-21.

²⁸¹³ PG&E-19-E, p. 10-16, line 27 to p. 10-17, line 7.

²⁸¹⁴ TURN-15, p. 12, lines 19-20.

²⁸¹⁵ PG&E-19-E, p. 10-12, lines 5-8.

free electricity sector by 2045.²⁸¹⁶ The Commission’s Building Decarbonization proceeding (R.19-01-011) is working to achieve California’s goal to reducing of greenhouse gas (GHG) emissions associated with energy use in buildings.²⁸¹⁷ The means of achieving these policy goals (such as increased electrification, use of renewables, and demand response) require a billing system that allows PG&E to implement rate programs based on increasing complexity.²⁸¹⁸ Since the current Billing System’s implementation in 2001, PG&E has applied customized solutions to meet the increase in CPUC-adopted rate programs²⁸¹⁹ However, two decades of customized changes has resulted in a lengthy and laborious process for programming new or improved rate structures that, given the increased number and complexity of approved rate programs has resulted in a backlog given that the system must be fully tested for many months after each such structural rate change has been made to ensure the whole billing system still functions smoothly.

The current billing system does not have the long-term capability to meet the complex requirements for programming new structural rate changes or additions. The Billing System Upgrade Project will implement a modular bill calculation framework, reducing the implementation time and costs for programming any new rate structures. However, until the new system is brought online, PG&E’s ability to construct rates to incentivize customer load shifting to hours with lower costs and less GHG intensive generation sources will be hamstrung.

The urgency for demand response was illustrated this summer over the 2022 Labor Day weekend, as California faced a dire heat wave and extraordinary demand on the electric grid.

2816 Sen. Bill No. 100 (2017-2018 Reg Sess.), https://leginfo.legislature.ca.gov/faces/billNavClient.xhtml?bill_id=201720180SB100, (as of Oct. 18, 2022).

2817 Assem. Bill No. 3232 (2017-2018 Reg. Sess.), https://leginfo.legislature.ca.gov/faces/billTextClient.xhtml?bill_id=201720180AB3232, (as of Oct. 18, 2022).

2818 PG&E-19-E, p. 10-11, lines 28-30.

2819 PG&E-19-E, p. 10-14, lines 8-13.

Only through coordinated statewide action were rolling blackouts avoided. This is just the most recent example. Against this backdrop, the Commission has ordered PG&E and the other utilities to implement real-time pricing pilots to test sending dynamic electricity price signals to eligible customers who are willing to opt onto a more volatile day-ahead hourly rate structure. Because such new dynamic pricing approaches necessarily employ a more complex rate structure than just Time-of-Use on-peak and off-peak blocks of hours each day, they either cannot be implemented, or at least cannot be efficiently or timely realized using the current billing system.²⁸²⁰ For example, when PG&E implemented changes to non-residential TOU periods in 2019, the TOU period adjustment required PG&E to create new rate schedule calculation routines with ten percent more calculation steps instead of changing only the bill usage calculations.²⁸²¹ In addition, the increased volume and complexity of rate schedule calculation routines has increased the amount of time required to deploy and deliver these changes.²⁸²²

The current billing system framework requires the modification of each complex rate schedule calculation routine to implement a new rate program, and each new program implementation consumes substantial time and cost. The current billing system does not have the long-term capabilities to meet the requirements for these new rate programs.²⁸²³ The complexity of the required rate structure means that certain elements cannot be implemented in the current billing system.²⁸²⁴ Reliability, decarbonization, and demand response programs need to be implemented as soon as possible after adoption to avoid missing additional summers of heat waves. Accordingly, PG&E has submitted its request in this GRC cycle.

²⁸²⁰ PG&E-06-E, p. 10-12, line 15-17; p. 10-15, lines 2-3.

²⁸²¹ PG&E-06-E, p. 10-11, lines 4-11.

²⁸²² PG&E-06-E, p. 10-11, lines 4-11.

²⁸²³ PG&E-19-E, p. 10-15, lines 15-20.

²⁸²⁴ PG&E-19-E, p. 10-15, lines 1-3.

PG&E's need for the Billing System Upgrade Project is urgent and essential. The program is not expected to have a positive cost-benefit, and indeed, the additional documentation TURN seeks would add further delays to the Project's rollout, and thus when complex new rate structures could be rolled out to customers. California is experiencing a climate and grid reliability emergency and empowering PG&E's customers to optimize their energy usage patterns is crucially important. This Project is not elective, as TURN's proposal implies, rather, prudence demands quick action, as PG&E has taken here.

6.12 Communications

PG&E's forecast for Communications will enable PG&E to inform customers about their service and how to prepare for emergencies, as well as communicate public safety information. It will also provide public notices in bill inserts, signs and newspaper ads for customer awareness and participation at CPUC led public hearings. PG&E TY 2023 forecast for department costs as reflected in opening testimony is \$23.578 million. PG&E's JCE forecast is \$24.651 million.²⁸²⁵ PG&E's expense forecast is uncontested. See Appendix A

6.13 Customer and Communications Ratemaking

The balancing accounts and memorandum accounts in Exhibit PG&E-06 are uncontested. Please see Appendix B for those balancing accounts and memorandum accounts PG&E requests be continued with modifications or closed at the end of this rate case period (December 31, 2022).

²⁸²⁵ PG&E-64, p. 3-4, Table 3A-1, lines 162-163.

7. SHARED SERVICES AND INFORMATION TECHNOLOGY (EXHIBIT PG&E-07)

7.1 Forecast

PG&E's Shared Services and Information Technology (IT) departments provide wide ranging services that benefit all lines of business. These services include the Safety Department, Transportation Services, Supply Chain – Materials Logistics and Planning, Supply Chain – Sourcing Operations, Corporate Real Estate, Environmental and Geosciences programs, Enterprise Records and Data Management, as well as IT. These organizations are critical for PG&E's safety and security efforts. For instance, PG&E's Safety Department is responsible for identifying, evaluating, and controlling hazards and risks to PG&E's employees and the public and PG&E's Transportation Services department supplies the trucks and equipment for emergency and incident response.

In terms of technology, PG&E – like utilities in general – is increasingly run on complex, sophisticated IT systems. Our IT organization must continually invest to maintain and grow a healthy asset base that can accommodate the demands of modern automation, communications, and security technologies. These systems and applications enable improvements in public and employee safety and customer service and are reducing the frequency and duration of outages. PG&E's IT organization is also responsible for improving cyber and physical security and addressing growing cyber and physical security risks. PG&E's TY 2023 expense forecast for Shared Services and IT as reflected in rebuttal testimony is \$744.036 million. PG&E's TY 2023 forecast as reflected in the Joint Comparison Exhibit or JCE (Exhibit PG&E-64), which includes the September 2022 updated escalation and all post-February 28, 2022 errata and concessions, is \$790.110 million.²⁸²⁶ Approximately \$133 million, 18 percent, of PG&E's TY 2023 expense forecast is undisputed.²⁸²⁷

²⁸²⁶ PG&E-64, p. 3-5, Table 3A-1, Total Exhibit (PG&E-07).

²⁸²⁷ See Appendix A, p. A-16, line 303. Calculated as: \$133 million / \$744 million = 18%.

PG&E's expense forecast for companywide expenses as reflected in opening testimony is \$154.509 million²⁸²⁸ of which approximately \$3.595 million is undisputed.²⁸²⁹ PG&E's TY 2023 forecast in the JCE is \$156.420 million.²⁸³⁰

PG&E capital expenditures forecast as reflected in rebuttal testimony is \$531.425 million in 2021, \$499.064 million in 2022, and \$1,473.117 million in 2023, \$628.014 million in 2024, \$689.630 million in 2025, and \$758.331 million in 2026. PG&E's capital expenditures forecast as reflected in the JCE is \$547.643 million in 2021, \$579.477 million in 2022, \$1,595.232 million in 2023, \$761.068, million in 2024, \$824.953 million in 2025, and \$895.569 million in 2026.²⁸³¹ Approximately \$94 million of PG&E's 2023 capital forecast, 6 percent, is undisputed.²⁸³²

The expense and capital forecasts for Sourcing, Land and Environmental Management, Cyber and Corporate Security, and Geosciences are undisputed.²⁸³³

After hearings, Cal Advocates, TURN, and PG&E worked collaboratively to resolve disputed issues relating to the Enterprise Data Management (EDM) and IT forecasts. As a result of this collaborative effort, the parties have reached a stipulation regarding PG&E's EDM and IT forecasts (the EDM/IT Stipulation), which is included as Appendix F to this Opening Brief. This stipulation is discussed in more detail in Sections 7.8.1 (EDM) and 7.9 (IT) below.

7.2 Enterprise Health And Safety/Occupational Health

Enterprise Health and Safety (EHS) is responsible for identifying, evaluating, and controlling hazards, risks, and exposures with the objective to protect PG&E's employees and

²⁸²⁸ PG&E-20-E, p. 1A-4, Table 1A-1, line 23.

²⁸²⁹ See Appendix A, p. A-27, line 5.

²⁸³⁰ PG&E-64, p. 3-19, Table 3C-1, lines 32-39.

²⁸³¹ PG&E-67, WP-4, Exhibit 7 Total.

²⁸³² See Appendix A, p. A-24, line 145. Calculated as: \$94 million / \$1,473 million = 6%.

²⁸³³ CALPA-10, p. 3, Table 10-1.

contractors, and the public.²⁸³⁴ Through the One PG&E Occupational Health and Safety Plan, EHS provides a governance role over the elements of workforce and public safety, while the execution of the programs themselves is performed by specific lines of business.²⁸³⁵ Occupational Health includes PG&E's workers compensation, disability, and on-site health care programs.²⁸³⁶

7.2.1 PG&E's Expense And Capital Forecast

PG&E's Enterprise and Occupational Health forecasts are comprised of two broad categories: (1) Enterprise Health and Safety activities, the forecasts for which no party contested, and (2) Occupational Health activities, which were partially opposed.

PG&E's TY 2023 expense forecast for Enterprise Health and Safety, as reflected in opening testimony is \$38.253 million.²⁸³⁷ PG&E's TY 2023 forecast in the JCE is \$38.617 million.²⁸³⁸ Expense work is tracked in four MWCs: MWC AB, Miscellaneous Expense; MWC FL, Safety Engineering and OSHA Compliance; MWC JV, Maintain IT Applications and Infrastructure; and MWC KX, Provide Human Resource Services. PG&E's expense forecast for Enterprise Health and Safety is undisputed, as indicated in Appendix A.

PG&E's capital expenditures forecast as reflected in opening testimony is \$0.9 million in 2021, \$1.0 million in 2022, \$1.0 million in 2023, \$1.0 million in 2024, \$1.0 million in 2025, and \$1.0 million in 2026.²⁸³⁹ PG&E's capital expenditures forecast in the JCE is \$0.927 million in 2021, \$1.161 million in 2022, \$1.210 million in 2023, \$1.212 million in 2024, \$1.196 million in

²⁸³⁴ PG&E-07, p. 1-1, lines 11-13.

²⁸³⁵ PG&E-07, p. 1-1, lines 13-21.

²⁸³⁶ PG&E-07, p. 1A-1, lines 7-9.

²⁸³⁷ PG&E-07, p. 1-52, Table 1-13, line 7.

²⁸³⁸ PG&E-64, p. 3-5, Table 3A-1, lines 165-168.

²⁸³⁹ PG&E-07, p. 1-52, Table 1-14, line 3.

2025, and \$1.181 million in 2026.²⁸⁴⁰ PG&E's capital work is tracked in MWC 2F, Build IT Applications and Infrastructure. PG&E's capital forecast for Enterprise Health and Safety is undisputed, as indicated in Appendix A.

PG&E's expense forecast for Occupational Health, companywide expenses, as reflected in rebuttal testimony is \$154.509 million.²⁸⁴¹ PG&E's TY 2023 forecast in the JCE is \$156.420 million.²⁸⁴² Some of PG&E's Occupational Health companywide expense forecast is disputed, as described below. Forecasts for On-Site Clinics, Fit for Duty (FFD), Department of Transportation Drug Testing, and Substance Abuse Intervention are uncontested. *See* Appendix A.

7.2.2 Summary Of Parties' Positions

Cal Advocates recommends a reduction of \$46.049 million to PG&E's Occupational Health companywide expense forecast.²⁸⁴³ Cal Advocates opposes PG&E's forecasts for Occupational Health companywide expenses for the following programs: (1) Transitional Light Duty Payroll; (2) Voluntary Plan and Third-Party Disability Management (LTD/STD Pay As You Go); (3) Wellness Programs; (4) Employee Assistance Programs; and (5) Mental Health Services, as set forth in Table 7-1 below.²⁸⁴⁴

²⁸⁴⁰ PG&E-67, WP-4; PG&E-07, p. 5-36, lines 1-4, MWC 22 and p. 7-27, line 6 to p. 7-29 line 19 MWC 2F.

²⁸⁴¹ PG&E-20-E, p. 1A-4, Table 1A-1, line 23.

²⁸⁴² PG&E-64, p. 3-19, Table 3C-1, lines 32-39.

²⁸⁴³ PG&E-20-E, p. 1A-4, Table 1A-1, line 23. Cal Advocates' recommended reduction is shown as \$47.029 million. PG&E agreed to remove the Substance Abuse Intervention forecast for \$0.979 million (line 22). Cal Advocates' adjusted recommendation, excluding the Substance Abuse Intervention Program, is \$46.049 million (calculated as: \$47.029 - \$0.979 = \$46.049).

²⁸⁴⁴ Cal Advocates also disputes PG&E's forecast for Long-Term Disability Trust Contributions. This issue is discussed with the Retiree Medical and Retiree Life Insurance Trust Contributions in Section 8.5.

TABLE 7-1
OCCUPATIONAL HEALTH AND SAFETY – COMPANYWIDE EXPENSES
PG&E’S EXPENSE FORECAST AND
PARTIES RECOMMENDED REDUCTIONS (\$000s)^(a)

Companywide Expense	PG&E’s 2023 Forecast	Cal Advocates’ Recommended Reduction
Transitional Light Duty Payroll	\$5,610	\$(494)
Long-Term Disability/Short-Term Disability Pay-As-You-Go	\$24,069	\$(22,017)
Long Term Disability (Trust Contributions)	\$45,313	\$(14,444)
Wellness	\$6,340	\$(2,502)
Employee Assistance Program	\$2,604	\$(745)
Mental Health Services	\$19,530	\$(5,847)
Total Contested Issues	\$103,466	\$(46,049)
(a) PG&E-20, p. 1A-4, Table 1A-1, lines 12, 15, 16, 18, 19, and 20.		

Cal Advocates’ recommendations are addressed in the subsections below.

7.2.3 Transitional Light-Duty Payroll

PG&E’s light-duty payroll will pay the wages of employees who are returned to work in a light or transitional capacity and meet certain criteria.²⁸⁴⁵ PG&E forecasts \$5.610 million for light-duty payroll.²⁸⁴⁶ Cal Advocates proposes a forecast of \$5.1 million and contends that the Commission should use a five-year average due to fluctuations in costs as a result of normal changes in activity levels.²⁸⁴⁷

PG&E’s forecast is based on an actuarial study conducted by Willis Towers Watson, which used the weighted average of the 2015-2019 recorded data and gave the most weight to 2019 and gradually less weight to each prior year to forecast the 2020 payments.²⁸⁴⁸ This method, which is the actuarial approach typically used in loss forecasting, is a more reliable methodology than that underlying Cal Advocates’ recommendation.

²⁸⁴⁵ PG&E-07, p. 1A-11, lines 10-12.

²⁸⁴⁶ PG&E-20-E, p. 1A-4, Table 1A-1, line 12.

²⁸⁴⁷ CALPA-11, p. 58, lines 1-13, and p. 57, Table 11-24.

²⁸⁴⁸ PG&E-07, p. 1A-12, lines 15-23, and PG&E-07, WP 1A-56 to WP 1A-73, and WP 1A-78.

PG&E then adjusted these results to account for forecast labor escalation for 2021-2023. Despite the fact that Cal Advocates does not oppose the 2023 labor escalation rate, it failed to take it into account when recommending a reduction.²⁸⁴⁹ Even using the unweighted five-year average of 2016-2020, as proposed by Cal Advocates, the figure adjusted for escalation is \$6.004 million (which is greater than PG&E's forecast); not Cal Advocates' proposed \$5.1 million. Therefore, the Commission should adopt PG&E's forecast because it includes the escalation rate, which all parties agree is proper.

7.2.4 Voluntary Plan And Third Party Disability Management (LTD/STD Pay As You Go)

PG&E offers a modified sick leave program, including a short-term disability program paid through a Voluntary Plan.²⁸⁵⁰ PG&E manages disability and other leave programs on a coordinated basis, using a single third party administrator. The third party administrator assures that PG&E's compliance is up-to-date with overlapping local, state, and federal laws and regulations governing disability and other leave policies, including medical leaves and the Family Medical Leave Act.²⁸⁵¹ PG&E forecasts \$22.297 million in expense for 2023 for the Voluntary Plan, which includes Short-Term Disability and Paid Family Leave benefits and their supplemental benefits. PG&E's forecast also includes \$1.772 million for the Third Party Disability Program Management costs, a combined forecast of \$24.069 million.²⁸⁵²

Cal Advocates recommended funding for these programs is \$2.1 million, a reduction of \$22.017 million.²⁸⁵³ Cal Advocates recommends that the Long Term Disability/Short Term

²⁸⁴⁹ PG&E-21, Ch. 4.

²⁸⁵⁰ PG&E-07, p. 1A-15, lines 13-14.

²⁸⁵¹ PG&E-07, p. 1A-19, lines 6-11.

²⁸⁵² PG&E-20-E, p. 1A-4, Table 1A-1, lines 13-15.

²⁸⁵³ CALPA-11, p. 61, line 1 to p. 62, line 21.

Disability Pay-As-You-Go (LTD/STD PAYGO) expense forecast be equal to the historic expense from **2016**, seven years prior to the test year.

PG&E's overall compensation and benefits package was found to be in line with the market in a study conducted by Willis Towers Watson.^{**2854**} These benefits "allow employees to take the time off necessary due to an injury or illness or to care for a family member who is ill," and must be adequately funded, as PG&E proposes to do.^{**2855**} Cal Advocates' recommendation that this expense be equal to the expense of 2016 – the lowest historical year – ignores that the cost of compensation and benefits has risen in the last five years. In fact, Cal Advocates offers no justification to select this single year over PG&E's.^{**2856**}

Additionally, there are forecast reductions in other plans as a result of the Voluntary Plan. When the Voluntary Plan was developed, PG&E redesigned time-off programs and eliminated sick time provisions for most employees.^{**2857**} As a result, employee unavailability due to health has decreased from over 8% in 2015 to 6.51% in 2021.^{**2858**} Each 1% reduction in Workforce Unavailable Due to Health results in an increase of about 270 full time available workers,^{**2859**} which allows PG&E to accomplish more work with fewer employees, thereby reducing the cost of salaries and benefits. The Commission should adopt PG&E's proposal, which is based on

2854 PG&E-20, PG&E's response to Data Request CalAdvocates_245-Q003, dated 2/10/22, pp. AppA-8 to AppA-9.

2855 PG&E-20, PG&E's response to Data Request CalAdvocates_245-Q003, dated 2/10/22, pp. AppA-8 to AppA-9.

2856 See, e.g., D. 20-07-038, p. 8 (finding that a party challenging a utility's forecast had an affirmative duty to establish why the utility's proposed methodology was unreasonable and that this burden is not met where the challenging party "merely isolated the data that it liked and asked that we focus solely on that period of time. That does not prove it was unreasonable or unlawful for us to prefer to set costs using a broader period of time that offered more information").

2857 PG&E-20-E, p. 1A-8, lines 3-5.

2858 PG&E-20-E, p. 1A-8, lines 12-15.

2859 PG&E-07, p. 1-14, lines 3-22 and WP 1-15.

more reasonable assumptions than those underlying Cal Advocates' recommendation. Only PG&E's proposal will allow it to continue to attract and retain a capable workforce.

7.2.5 Wellness Programs

PG&E's Wellness programs include, but are not limited to, Health Screenings and Coaching, Flu Shot Clinics, and Tobacco Cessation programs. Wellness programs are intended to help employees and their dependents increase their awareness of, and take actions to improve, their health, to prevent illness, to produce an engaged and healthy workforce, and thereby promote safer and more efficient utility operations.²⁸⁶⁰ PG&E forecasts \$6.340 million for the Wellness program.²⁸⁶¹ Cal Advocates recommends \$3.8 million for these programs based on a three-year historical average. Cal Advocates contends that PG&E did not sufficiently describe these programs in its testimony.²⁸⁶²

Contrary to Cal Advocates' assertion, PG&E provided discussion of the Wellness program in its testimony²⁸⁶³ and discovery responses, including a detailed description of components of the Wellness program.²⁸⁶⁴ Additional information about the Wellness program components, including a wellness pilot program, were included in PG&E's 2020 RAMP Report.²⁸⁶⁵ PG&E has provided sufficient information to demonstrate that its Wellness program is reasonable.

Cal Advocates' proposal to forecast this program based on three years (2018-2020) is flawed, because it fails to consider escalation, increase in employee headcount, and fluctuations

²⁸⁶⁰ PG&E-20-E, p. 1A-8, line 22 to p. 1A-9, line 2.

²⁸⁶¹ PG&E-20-E, p. 1A-4, Table 1A-1, line 18.

²⁸⁶² CALPA-11, p. 64, lines 5-10.

²⁸⁶³ PG&E-07, p. 1-14, lines 3-22 and WP 1-15.

²⁸⁶⁴ PG&E-20, PG&E's response to Data Request CalAdvocates_051-Q12, Subpart a, dated 9/15/21, pp. AppA-2 to AppA-4.

²⁸⁶⁵ PG&E-07, WP 1A-22.

over time.²⁸⁶⁶ Cal Advocates notes that this program cost \$7.2 million in each of 2016 and 2017, but suggests the Commission ignore these years without explanation – presumably because this lowers the average cost.²⁸⁶⁷ PG&E’s five-year average of base year dollars should be used because it accounts for fluctuations over time and is adjusted for escalation and forecast increase in headcount.²⁸⁶⁸

7.2.6 Employee Assistance Program

The Employee Assistance Program (EAP) is a work-based intervention program designed to assist employees in resolving personal problems that may adversely affect performance. The EAP assists workers with issues like alcohol or substance use disorders, relationship challenges, financial or legal problems, emotional issues, stress, wellbeing, and traumatic events like workplace violence, coworker accidents or deaths, or natural disasters.²⁸⁶⁹

PG&E forecasts \$2.604 million for its EAP program.²⁸⁷⁰ Cal Advocates recommends \$1.9 million for EAP based on a three-year historical average. Cal Advocates contends that PG&E did not support or justify its forecast.²⁸⁷¹ PG&E’s forecast is sufficiently supported in testimony²⁸⁷² and discovery responses.²⁸⁷³ Cal Advocates’ proposed use of a three-year average fails to consider escalation, increase in per employee per month fees, or increase in

²⁸⁶⁶ PG&E-20-E, p. 1A-9, lines 19-24.

²⁸⁶⁷ CALPA-11, p. 64, lines 2-5.

²⁸⁶⁸ PG&E-20-E, p. 1A-9, lines 19-27.

²⁸⁶⁹ PG&E-20-E, p. 1A-10, lines 10-15.

²⁸⁷⁰ PG&E-20-E, p. 1A-4, Table 1A-1, line 19.

²⁸⁷¹ CALPA-11, p. 64, line 17.

²⁸⁷² PG&E-07, p. 1-14, lines 23-32.

²⁸⁷³ PG&E-20, PG&E’s response to Data Request CalAdvocates_051-Q12, Subpart b, dated 9/15/21, pp. AppA-2 to AppA-4 and CalAdvocates_245-Q006, dated 2/10/22, pp. AppA-10 to AppA-11.

headcount; none of which are otherwise disputed or questioned by Cal Advocates.²⁸⁷⁴ PG&E's forecast accounts for these factors, is more accurate, and should be adopted.

7.2.7 Mental Health Services

Mental health services, also referred to as EAP-Medical, include one-on-one confidential support for a variety of life events and concerns. Individuals are eligible for up to six sessions per 6-month period. Mental health services can support many individual concerns, such as family and relationship problems, workplace concerns, alcohol and drug issues, depression, anxiety, and stress at home or work. It is an important component of the Health and Wellness Management Programs since employee issues can negatively affect work performance and safety on the job and at home.²⁸⁷⁵

PG&E forecast \$19.530 million for Mental Health Services.²⁸⁷⁶ Cal Advocates recommends a reduction of \$5.847 million based on a three-year historical average.²⁸⁷⁷

Cal Advocates' forecast does not take into consideration increased costs arising from the COVID-19 pandemic or change in laws. The COVID-19 pandemic changed the mental health landscape in several important ways. First, it significantly increased the number of people experiencing mental health symptoms.²⁸⁷⁸ Second, it influenced California law makers to pass a new law requiring providers to give mental health and substance abuse patients a follow-up visit within 10 days, which increases cost.²⁸⁷⁹ The methodology employed by Cal Advocates should not be adopted as it fails to account for the widespread impact of the pandemic.

²⁸⁷⁴ PG&E-08, WP5 Vol I-20 and WP5 Vol I-27.

²⁸⁷⁵ PG&E-07, p. 1A-11, lines 23-28.

²⁸⁷⁶ PG&E-20-E, p. 1A-4, Table 1A-1, line 20.

²⁸⁷⁷ CALPA-11, p. 64-65.

²⁸⁷⁸ PG&E-20-E, p. 1A-12, lines 10-12.

²⁸⁷⁹ Sen. Bill No. 221 (2021-2022 Reg. Sess.). Providers can authorize less frequent visits.

PG&E's mental health programs would be underfunded by Cal Advocates' proposed methodology, which is not supported by any analysis of the factors impacting PG&E's costs. The mental health and wellbeing of PG&E employees is of paramount importance to PG&E's ability to carry out its work. PG&E relies on the actuarial forecast provided by Mercer, which specifically considers PG&E's plans, PG&E employee demographics, and the Northern California environment when developing its forecast.²⁸⁸⁰ PG&E then applies a headcount adjustment to generate its forecast. The 2021 actual mental health costs were 98% of the forecast provided by Mercer in support of PG&E's original finding, which demonstrates that Mercer's methodology is reliable and should be used to forecast this expense.²⁸⁸¹

7.3 Transportation And Aviation Services

Transportation and Aviation Services includes the transportation services and aviation services organizations. Together, these organizations manage over 14,000 vehicles and related equipment utilized across PG&E's service territory. This includes all vehicles, construction equipment, trailers and aircraft, including rentals, supporting safe, reliable and efficient service.²⁸⁸²

7.3.1 Expense And Capital Forecasts

PG&E's TY 2023 expense forecast as reflected in rebuttal testimony is \$118.082 million.²⁸⁸³ PG&E's TY 2023 forecast in the JCE is \$136.071 million.²⁸⁸⁴ Expense work is tracked in four MWCs, two of which are undisputed: MWC BP, Manage DCPD Business; and MWC JV, Maintain IT Applications and Infrastructure, as indicated in Appendix A. The primary drivers of forecasted expense increases are (1) escalation; (2) higher costs to operate the

²⁸⁸⁰ PG&E-20-E, p. 1A-12, lines 4-6.

²⁸⁸¹ PG&E-20-E, p. 1A-12, lines 17-22.

²⁸⁸² PG&E-07, p. 2-1, lines 14-16.

²⁸⁸³ PG&E-20-E, p. 2-3, Table 2-1, line 5.

²⁸⁸⁴ PG&E- 64, p. 3-5, Table 3A-1, lines 169-172.

fleet, including maintenance, fuel, labor and rentals; (3) increased depreciation costs inclusive of base fleet and additional book value associated with green fleet lifecycle replacements; and IT initiatives for system and database enhancements.²⁸⁸⁵

PG&E capital expenditures forecast as reflected in rebuttal testimony is \$98.678 million in 2021, \$64.677 million in 2022, and \$107.569 million in 2023. PG&E's attrition year forecasts are \$108,756 in 2024, \$145,863 in 2025, and \$246,079 in 2026.²⁸⁸⁶ PG&E's capital expenditures forecast in the JCE is \$101.689 million in 2021, \$75.098 million in 2022, \$130.173 million in 2023, \$131.798 million in 2024, \$174.485 million in 2025, and \$290.612 million in 2026.²⁸⁸⁷ PG&E's capital work is tracked in three MWCs, two of which are undisputed: MWC 05, Tools and Equipment; and MWC 2F, Build IT Applications and Infrastructure. See Appendix A. The majority of the capital expenditure forecast is vehicle replacements based on the useful lifecycle of each assets type. A smaller part of the forecast includes electric vehicle purchases and replacement due to accidents.²⁸⁸⁸

The disputed expense and capital forecasts are addressed in the subsections below.

7.3.2 Transportation Services Expense (MWC AB)

MWC AB includes several categories of expense: vehicles, depreciation, fuel and rentals. The vehicle forecast is estimated primarily by using historic costs including labor, parts, registration and freight. The depreciation forecast is based on CPUC-authorized fleet depreciation rates. The fuel and rentals forecasts are estimated using historic costs in relation to work plans and targets forecast by the lines of business.²⁸⁸⁹

²⁸⁸⁵ PG&E-07, p. 2-3, lines 3-8.

²⁸⁸⁶ PG&E-20-E, p. 2-15, Table 2-5, line 5.

²⁸⁸⁷ PG&E-67, WP-4; PG&E-07, Ch. 2, MWCs 04, 05, and Ch. 3, MWCs 21, and 2F.

²⁸⁸⁸ PG&E-07, p. 2-4, lines 2-6.

²⁸⁸⁹ PG&E-07, p. 2-27, lines 25-30.

PG&E forecast \$265.767 million for miscellaneous expense in MWC AB.²⁸⁹⁰ The fuel expense portion of MWC AB is \$18.8 million (approximately 16 percent of the MWC AB forecast). Fuel expense supports day-to-day operations as well as emergency events such as wildfire.²⁸⁹¹

Cal Advocates recommends a net fuel expense reduction of \$3.459 million. Cal Advocates challenges PG&E's use of a 1.55 percent consumption growth rate to develop its forecast and recommends using a historical 2-year average (2018-2019) of fuel consumption.²⁸⁹² Cal Advocates does not oppose PG&E's forecasted 2023 price per gallon. The parties' positions are set forth in Table 7-2 below.

TABLE 7-2
FUEL EXPENSE (MWC AB)
PG&E'S EXPENSE FORECAST AND
PARTIES RECOMMENDED REDUCTIONS (\$000s)^(a)

Party	2020 Rec.	2021	2022	2023
PG&E	\$258,903	\$252,805	\$259,891	\$265,767
Cal Advocates				\$(5,901)
(a) PG&E-20, p. 2-15, Table 2-4, line 1; PG&E-64, p. JCE 7-18 (Cal Advocates' recommendation)				

Contrary to Cal Advocates' position, PG&E's 1.55 percent growth rate is amply supported. This growth rate was derived from the average increase in miles driven per employee over a three-year (2017-2019) historical period. Mobile fuel consumption was calculated using a 5-year (2016-2020) average that was adjusted for outliers with a 3 percent rate of escalation in 2021 to 2023.²⁸⁹³

²⁸⁹⁰ PG&E-20-E, p. 2-3, Table 2-1, line 1.

²⁸⁹¹ PG&E-20-E, p. 2-5, lines 12-17.

²⁸⁹² CALPA-10, p. 9, line 12 to p. 11, line 17.

²⁸⁹³ PG&E-20-E, p. 2-6, lines 14-18.

PG&E's projected headcount growth, fleet growth, and miles driven are all increasing faster than 1.55 percent.²⁸⁹⁴ In addition, PG&E's actual 2021 fuel consumption and forecast 2022 run rate are both significantly higher than 1.55 percent.²⁸⁹⁵ By contrast, Cal Advocates' use of a 2017-2019 historical average ignores this growth. The Commission should adopt PG&E's forecast.

7.3.3 Vehicle Expense (MWC AB)

PG&E's forecast for vehicle expense in MWC AB is \$41.1 million (approximately 35 percent of the MWC AB forecast). The vehicle expense is necessary to maintain and deploy safe, reliable, compliant, cost-effective vehicles and equipment to provide gas and electric services to our customers 24 hours a day, 365 days a year.²⁸⁹⁶

Cal Advocates recommends that the labor portion of PG&E's gross vehicle expense forecast in 2023 be reduced by \$3.153 million, resulting in a net reduction of \$2.442 million. Cal Advocates' forecast is based on a lower forecasted labor headcount than in PG&E's forecast.²⁸⁹⁷ Cal Advocates does not oppose the Materials & Contract, Registration, Freight, Telematics, or Other Miscellaneous 2023 forecasts.

PG&E has a contractual obligation with the union to maintain a ratio between vehicles and union employees of 35:1, plus or minus 10 percent. Cal Advocates proposed headcount is within the range but at the low end of staffing (i.e., there are more than 35 vehicles per union employee). Cal Advocates argues that this is reasonable because there is no penalty for falling below the 10 percent threshold and because the size of PG&E's fleet does not appear to be increasing.²⁸⁹⁸ But merely being within the allowable variance for staffing levels is not

²⁸⁹⁴ PG&E-20-E, p. 2-7, line 20 to p. 2-8, line 2.

²⁸⁹⁵ PG&E-20-E, p. 2-7, lines 14-18.

²⁸⁹⁶ PG&E-20-E, p. 2-5, lines 17-21.

²⁸⁹⁷ CALPA-10, p. 11, lines 27-28.

²⁸⁹⁸ CALPA-10, p. 13, line 25 to p. 14, line 14.

appropriate. The 35:1 staffing ratio is the agreed upon optimal staffing level to meet safety and compliance requirements; staffing below that level can result in increased overtime, lower vehicle availability, and delays in repair times. The 10 percent variance is to allow for temporary fluctuations in the counts of vehicles and union employees and should not be incorporated into staffing targets.²⁸⁹⁹ In addition, although the vehicle fleet may not have grown significantly, vehicle maintenance workload has increased due to fire risk reduction initiatives, increased regulatory inspection requirements and vehicle safety campaigns that have led to a significant increase in work orders.²⁹⁰⁰ Cal Advocates' headcount recommendation should be rejected and PG&E's forecast adopted.

7.3.3.1 Overhead Credit (MWC ZC)

Overhead Credit (MWC ZC) represents the offsetting credit as the Transportation overhead is applied (debited) to applicable capital and balancing account expense projects.²⁹⁰¹

PG&E's forecast for Overhead Credit is \$(149.762) million.²⁹⁰² To calculate the overhead credit forecast, PG&E uses three years (2017-2019) of recorded data. This provides historical reference without going too far back to miss incorporating significant changes to the business (i.e., wildfire support, system hardening, etc.). Additionally, PG&E further adjusted (lowered) the credit to reflect that PG&E will stop applying this overhead to almost all balancing account expense orders.²⁹⁰³ Cal Advocates is the only party to object to this forecast. The differences between PG&E's and Cal Advocates' forecasts are set forth below.

²⁸⁹⁹ PG&E-20-E, p. 2-9, line 28 to p. 2-10, line 20.

²⁹⁰⁰ PG&E-20-E, p. 2-10, lines 5-13.

²⁹⁰¹ PG&E-20-E, p. 2-10, lines 23-25.

²⁹⁰² PG&E-20-E, p. 2-3, Table 2-1, line 4.

²⁹⁰³ PG&E-20-E, p. 2-11, lines 3-9.

TABLE 7-3
OVERHEAD CREDIT (MWC ZC)
PG&E’S EXPENSE FORECAST AND
PARTIES RECOMMENDED REDUCTIONS (\$000s)^(a)

Party	2020 Rec.	2021	2022	2023
PG&E	\$(156,577)	\$(147,352)	\$(152,744)	\$(149,762)
Cal Advocates				\$6,880
(a) PG&E-20, p. 2-15, Table 2-4, line 4; PG&E-20, p. 2-3, PG&E-64, p. JCE 7-22 (Cal Advocates)				

Cal Advocates recommends an adjustment to Overhead Credit of \$6.880 million based on its preference for using five years (2016-2020) of historical data.²⁹⁰⁴ Cal Advocates’ recommendation results in an overhead credit percentage of 59.80 percent in contrast to PG&E’s 55.91 percent. This results in Cal Advocates’ test year 2023 forecast of \$156.642 million, which is \$6.880 million lower than PG&E’s TY 2023 forecast.²⁹⁰⁵

The Commission should not adopt Cal Advocates’ recommendation. As of 2020, the “Fleet Overhead” credit is no longer applied to balancing account expense orders for 2020 GRC period-jurisdictional balancing accounts.²⁹⁰⁶ In the 2023 GRC, PG&E proposes to extend this accounting treatment to GT&S balancing accounts. The “Fleet Overhead” will no longer be applied to balancing account expense orders without preexisting agreements.²⁹⁰⁷ Given the recent accounting changes removing the fleet overhead credit from balancing accounts, it is not appropriate to use a five-year historical average to forecast as we do not have five years of recorded data with this cost model change in place. PG&E’s forecast accounts for this change and should be adopted

7.3.4 Fleet/Automotive Equipment (MWC 04)

MWC 04 includes the capital expenditure forecasts for vehicle replacements based on the useful lives of different asset types. Transportation services vehicle replacement plan aligns with

2904 *Id.*, lines 22-24.

2905 *Id.*, lines 24-27.

2906 D.20-12-005, pp. 409-411, OP 1.

2907 PG&E-12, p. 7-25 to p. 7-26.

the overall goals to provide safe, reliable, compliant, and cost-effective vehicles and equipment to provide gas and electric services.²⁹⁰⁸ PG&E’s capital request for heavy-duty vehicles from 2023 to 2026 is \$307 million; \$46 million in 2023, \$49 million in 2024, \$87 million in 2025, \$125 million in 2026. PG&E’s 2023 request is a decrease from 2020 recorded capital expenditures. The primary driver of the increases, including the substantial increase in 2026, is planned vehicle replacements based on the useful lives of different asset types.

AARP was the sole party to object to PG&E’s forecast for this program as indicated below.

TABLE 7-4
TRANSPORTATION AND AVIATION SERVICES CAPITAL (MWC 04)
PG&E’S CAPITAL FORECAST AND
RECOMMENDED REDUCTIONS (\$000s)^(a)

Party	2020 Rec.	2021	2022	2023	2024	2025	2026
PG&E	\$110,061	\$97,313	\$61,947	\$104,811	\$105,972	\$143,951	\$244,138
AARP				\$(12,344)	\$(13,505)	\$(51,484)	\$(151,671)
(a) PG&E-20, p. 2-15, Table 2-5, line 1; PG&E-20, p. 2-4, Table 2-2, line 1 (AARP’s recommendation).							

AARP recommends a capital reduction of \$229 million from 2023 to 2026, based on its comparison of PG&E’s forecast capital spending to the 2017-2022 average of \$75.7 million and AARP’s proposal to extend PG&E’s planned heavy vehicle purchases by several years.²⁹⁰⁹

AARP’s proposed reductions are unsupported. First, the comparison to the 2017-2022 average capital spend is inapposite. The \$75.7 million relied upon by AARP has an artificially low number of Class 7 and 8 heavy trucks due to accelerated purchases in prior years prompted by Air Resources Board regulations. During 2017-2022 only 18% of capital spending was on Class 7 and 8 vehicles, but these vehicle types – Medium Line Truck, Heavy Line Truck, Large Aerial Truck, Dump Truck, and Gas Crew Truck – represent 35% of embedded capital costs.

2908 PG&E-07, p. 2-31, lines 26-29.

2909 AARP-01, p. 62, lines 12-19.

Further delaying purchases of these Class 7 and 8 heavy trucks will create an even bigger imbalance in PG&E's capital plan.²⁹¹⁰

Second, AARP's observation that "vehicles can remain in safe and reliable condition long past the end of their depreciation period" is based on its witnesses experiences with their own, personal vehicles, not on any knowledge of the wear and tear on, or required additional maintenance on, PG&E's heavy duty truck fleet.²⁹¹¹ AARP witness Alvarez acknowledged at the hearing that comparing his mileage experience with his personal vehicle was not a direct comparison.²⁹¹² In fact, it is not a meaningful comparison at all and should be accorded no weight.

PG&E's asset life cycle is set at 13 years, longer than the 7-10 year average of other gas and electric utilities and a major utility rental vehicle company for these heavy duty trucks.²⁹¹³ Moreover, while maintenance might keep the vehicles running as they age, there is a clear trend of increased downtime and repair as a vehicle ages.²⁹¹⁴ Increased downtime and repair has a cascading impact, with workers in the field finding themselves without the tools they need to do their job, not to mention the additional cost of repairs. Past the 13-year life, PG&E would be spending more that the worth of the entire vehicle on repairs.²⁹¹⁵

AARP has not met its burden to support its alternate forecast for heavy duty fleet vehicles. The Commission should adopt PG&E's forecast.

²⁹¹⁰ PG&E-20-E, p. 2-13, lines 8-17.

²⁹¹¹ Tr. Vol. 12, 2318:12-2319:27, AARP/Alvarez+Stephens.

²⁹¹² Tr. Vol. 12, 2319:25-27, AARP/Stephens.

²⁹¹³ PG&E-20-E, p. 2-13, lines 18-23.

²⁹¹⁴ PG&E-20-E, p. 2-13, lines 26-27.

²⁹¹⁵ PG&E-20-E, p. 2-13, line 30 to p. 2-14, line 2.

7.4 Materials

Materials includes the expense and capital expenditures forecasts for PG&E's Material and Distribution Operations department as well as the Materials and Supplies (M&S) inventory forecast. Materials manages a materials distribution network through PG&E's service territory in support of its maintenance and construction activities. The management and delivery of M&S inventory is a critical component of the safe, reliable and affordable service PG&E provides its customers.²⁹¹⁶

PG&E's TY 2023 expense forecast for materials in MWC AB as reflected in rebuttal testimony is \$1.704 million.²⁹¹⁷ PG&E's TY 2023 forecast in the JCE is \$1.739 million.²⁹¹⁸

PG&E capital expenditures forecast as reflected in rebuttal testimony is \$1.2 million in 2021, \$1.8 million in 2022, \$1.2 million in 2023, \$1.2 million in 2024, \$1.2 million in 2025, and \$1.2 million in 2026.²⁹¹⁹ PG&E's capital expenditures forecast in the JCE is \$1.237 million in 2021, \$2.090 million in 2022, \$1.452 million in 2023, \$1.454 million in 2024, \$1.435 million in 2025, and \$1.417 million in 2026.²⁹²⁰ PG&E's capital work is tracked in two MWCs: MWC 05, Tools and Equipment; and MWC 21, Miscellaneous Capital. PG&E's capital forecast is undisputed. See Appendix A.

Below, we address the expense forecasts related to our Materials program.

7.4.1 Miscellaneous Expense (MWC AB)

MWC AB reflects administrative and generation (A&G) expense for mail services. The recorded and forecasted costs were adjusted for escalation. PG&E's TY 2023 forecast for MWC

²⁹¹⁶ PG&E-07, p. 3-1, lines 6-16.

²⁹¹⁷ PG&E-20-E, p. 3-3, Table 3-1, line 4.

²⁹¹⁸ PG&E-64, p. 3-5, Table 3A-1, line 173.

²⁹¹⁹ PG&E-20-E, p. 3-8, Table 3-5, line 4.

²⁹²⁰ PG&E-67, WP-4; PG&E-07, Ch. 3, MWCs 05, 21 and 2F.

AB as presented in rebuttal testimony is \$1.704 million.²⁹²¹ PG&E’s forecast, which reflects the cost of ongoing service based on current headcount and associated labor escalations, is reasonable and undisputed.²⁹²²

7.4.2 Procure Materials and Services (MWC JL)

MWC JL tracks the recorded standard cost variance. As noted in the table below, PG&E does not forecast standard cost variances because “[v]ariations in the material burden overhead and material consumption rates that drive cost allocations are unpredictable and the periodic refinement of the material burden rate attempts to get the net cost as close to the \$0 as possible.”²⁹²³ Cal Advocates proposes a disallowance based on its own forecast of a standard cost variance based on a historical average, as summarized in Table 7-5 below:

**TABLE 7-5
PROCURE MATERIALS AND SERVICES (MWC JL)
PG&E’S EXPENSE FORECAST AND
PARTIES RECOMMENDED REDUCTIONS (\$000s)^(a)**

Party	2020 Rec.	2021	2022	2023
PG&E	\$(7,675)	\$--	\$--	\$--
Cal Advocates				\$(1,175)
(a) PG&E-20, p. 3-6, Table 3-4, line 1; PG&E-20, p. 3-3, Table 3-1, line 1 (Cal Advocates’ recommendation)				

Cal Advocates’ recommended reduction is based a five-year average of the standard cost variance from 2016-2020, resulting in a downward adjustment to PG&E’s overall materials expense forecast.²⁹²⁴ The Commission should reject Cal Advocates proposed adjustment to Materials expense based on historical standard cost variances because historical performance is not a reliable indicator for MWC JL.²⁹²⁵

²⁹²¹ PG&E-20-E, p. 3-3, Table 3-1, line 4.

²⁹²² PG&E-20-E, p. 3-6, line 29 to p. 3-7, line 10.

²⁹²³ CALPA-10, p. 17, lines 19-27, quoting PG&E’s response to a data request from Cal Advocates.

²⁹²⁴ PG&E-20-E, p. 3-6, lines 15-17.

²⁹²⁵ PG&E-20-E, p. 3-7, lines 8-10.

7.5 Sourcing

Sourcing is responsible for the procurement of goods and services and provides oversight for day-to-day supply chain activities and functional guidance to all PG&E departments regarding all procurement policies and procedures. Sourcing also supports PG&E's supplier diversity and sustainability efforts.²⁹²⁶

PG&E's TY 2023 expense forecast as reflected in opening testimony is \$26.390 million.²⁹²⁷ PG&E's TY 2023 forecast in the JCE is \$26.837 million.²⁹²⁸ The primary driver of the slight increase in expense is escalation.²⁹²⁹ PG&E expense forecast is undisputed, as indicated in Appendix A.

PG&E's capital expenditures forecast as reflected in opening testimony is \$0.470 million in 2021, \$0 in 2022, and \$0 in 2023.²⁹³⁰ PG&E's capital expenditures forecast in the JCE is \$0.484 million in 2021.²⁹³¹ These costs are investments in technology necessary to continue development and deployment of core procurement software, a critical component of sustained operational efficiency.²⁹³² PG&E's capital work is tracked in MWC 2F, Build IT Applications and Infrastructure. PG&E's capital forecast is also undisputed, as indicated in Appendix A.

7.6 Real Estate

PG&E's Real Estate organization, known as Corporate Real Estate Strategy and Services (CRESS), is responsible for governing, planning, acquiring, designing, constructing, operating, and maintaining 7.7 million square feet of facilities throughout PG&E's service territory. These

²⁹²⁶ PG&E-07, p. 4-6, lines 4-10.

²⁹²⁷ PG&E-07, p. 4-19, Table 4-5, line 18.

²⁹²⁸ PG&E-64, p. 3-5, Table 3A-1, lines 175-177.

²⁹²⁹ PG&E-07, p. 4-2, lines 23-26.

²⁹³⁰ PG&E-07, p. 4-20, Table 4-6, line 2.

²⁹³¹ PG&E-64, p. 3-16, Table 3B-3, line 116 (2021); PG&E-64, p. 3-12, Table 3B-2, line 116 (2022); and PG&E-64, p. 3-8, Table 3B-1, line 116 (2023).

²⁹³² PG&E-07, p. 4-4, lines 2-6.

facilities include service centers, data centers, contact, centers, office buildings, shops, warehouses, construction and equipment yards, vehicle maintenance garages, customer service offices, and meeting and training facilities.²⁹³³

PG&E's TY 2023 expense forecast as reflected in rebuttal testimony is \$60.938 million.²⁹³⁴ PG&E's TY 2023 forecast in the JCE is \$64.382 million.²⁹³⁵ The primary drivers of increases to the expense forecast are escalation, activities to transition from COVID-19 work-from-home conditions to more normal operations, and the headquarters move from San Francisco General Office to the Oakland General Office.²⁹³⁶

PG&E capital expenditures forecast as reflected in rebuttal testimony is \$182.0 million in 2021, \$176.0 million in 2022, \$1,044.721 million in 2023, \$183.0 million in 2024, \$181.0 million in 2025, and \$160.0 million in 2026.²⁹³⁷ PG&E's capital expenditures forecast in the JCE is \$187.544 million in 2021, \$204.358 million in 2022, \$1,076.813 million in 2023, \$221.771 million in 2024, \$216.517 million in 2025, and \$188.956 million in 2026.²⁹³⁸ The primary reason for the increase in capital expenditures is the purchase of and transition to the Oakland General Office and investment in service centers.²⁹³⁹

Below, we address disputed expense and capital forecasts related to CRESS by MWC.

7.6.1 Manage Properties And Buildings (MWC EP)

Manage Property & Buildings includes facility services to maintain appropriate levels of operational readiness and reliability for facilities, grounds, buildings, and systems. Typical

²⁹³³ PG&E-07, p. 5-1, lines 11-19.

²⁹³⁴ PG&E-20-E, p. 5-3, Table 5-1, line 9.

²⁹³⁵ PG&E-64, p. 3-5, Table 3A-1, lines 178-183.

²⁹³⁶ PG&E-07, p. 5-2, lines 11-12.

²⁹³⁷ PG&E-20-E, p. 5-22, Table 5-5, line 4.

²⁹³⁸ PG&E-67, WP-4; PG&E-07, Ch. 5, MWCs 22, 23 and 2F.

²⁹³⁹ PG&E-07, p. 5-3, lines 5-9.

services include janitorial, repairs and maintenance, landscape management, purchase of utilities such as water, sewer, gas, electricity, waste disposal and recycling services, rent and operating expense for leased facilities, mail delivery, and conference center services.²⁹⁴⁰ PG&E forecast \$109.527 million for MWC EP. Cal Advocates recommends a reduction of \$14.412 million, split between two activities – Conference Centers Program and Facilities Management Program — as discussed below.²⁹⁴¹

TABLE 7-6
MANAGE PROPERTIES AND BUILDINGS (MWC EP)
PG&E’S EXPENSE FORECAST AND
PARTIES RECOMMENDED REDUCTIONS (\$000s)^(a)

Party	2020 Rec.	2021	2022	2023
PG&E	\$117,051	\$111,900	\$117,642	\$109,527
Cal Advocates				\$(14,412)
(a) PG&E-20, p. 5-22, Table 5-4, line 2; PG&E-64, p. JCE 7-35 (Cal Advocates)				

7.6.1.1 Conference Centers Program

The Conference Centers program provides for the operation and maintenance of PG&E’s conference and training facilities, which include the San Ramon Valley Conference Center (SRVCC), Livermore Electric Safety Academy, Winters Gas Safety Academy, and San Francisco General Office Conference Center (which will transition to Oakland).²⁹⁴²

Cal Advocates proposes a 2023 expense reduction²⁹⁴³ of \$3.813 million to PG&E’s forecast of \$12.051 million, for a recommended 2023 forecast of \$8.238 million. Cal Advocates disagrees with the methodology used by PG&E to calculate this program’s forecast costs and

²⁹⁴⁰ PG&E-20-E, p. 5-5, lines 20-26.

²⁹⁴¹ PG&E-20-E, p. 5-3, Table 5-1, line 2.

²⁹⁴² PG&E-20-E, p. 5-5, line 30 to p. 5-6, line 2.

²⁹⁴³ CALPA-10, p. 2, lines 11-13.

instead uses a 2-year historical average (2018 and 2019) and proposes its own alternative methodology.²⁹⁴⁴ Cal Advocates' proposal is flawed for several reasons.

First, the two years (2018 and 2019) upon which Cal Advocates bases its forecast are not representative of PG&E's Conference Center program costs. Cal Advocates' proposal ignores information showing that Conference Center costs historically decreased from 2016-2019 due to enterprise-wide affordability efforts, which curtailed spending across PG&E. Cal Advocates cites to continued enterprise-wide affordability efforts in support of its proposed 2023 forecast.²⁹⁴⁵ PG&E's 2023 forecast for Conference Center program costs reflects plans to return to normal operations, which will include training and conference volumes that reflect current business expectations of at least pre-bankruptcy and/or pre-pandemic volumes.²⁹⁴⁶

Second, PG&E's 2023 forecast reflects increasing costs due to implementing new COVID-19 protocols. Cal Advocates challenges COVID-19 protocols as a basis for increased costs, asserting that the degree and duration of the need for COVID-19 protocols is unknown.²⁹⁴⁷ But based on our experience with the COVID-19 protocols that have evolved over the past two years and those currently in place, it is reasonable to assume increased costs for future or ongoing COVID-19 protocols or best practices to maintain pandemic mitigations going forward. In fact, it would be unreasonable not to include increased costs for future or ongoing COVID-19 protocols during 2023-2026 in the face of the continued presence of COVID-19 in PG&E's service territory.²⁹⁴⁸

Lastly, PG&E's 2023 forecast also reflects expected loss of external revenue credits previously realized through third-party conference center rentals. Cal Advocates ignores this

²⁹⁴⁴ CALPA-10, p. 2, lines 13-16.

²⁹⁴⁵ CALPA-10, p. 25, lines 7-11.

²⁹⁴⁶ PG&E-20-E, p. 5-6, line 17 to p. 5-7, line 7.

²⁹⁴⁷ CALPA-10, p. 25, lines 1-4.

²⁹⁴⁸ PG&E-20-E, p. 5-7, lines 8-22.

reason for an increase in PG&E’s costs on the grounds that “the extent of loss of external revenue credit is also unknown and will depend on future usage patterns.”²⁹⁴⁹ PG&E has proposed a reasonable forecast reflecting our plan to utilize all existing training and conference capacity to support PG&E. We do not expect excess capacity to be available for marketing to third parties. In the past, PG&E achieved some cost savings from third party rental of the Pacific Energy Center and the SRVCC. The Pacific Energy Center is now permanently closed. Additionally, during the period of the pandemic response, the SRVCC was utilized by PG&E for training, conference, and development of interim control centers and PG&E expects these activities to continue.²⁹⁵⁰

7.6.1.2 Facilities Management Program

The Facilities Management program provides the service to operate and maintain the Company’s facilities that are managed by CRESS and includes building management such as the CRESS Facilities Services team and its alliance partner costs, janitorial and enhanced cleaning, repairs to existing facilities for break/fix items, routine maintenance – including periodic testing and inspection, landscape maintenance and repairs, and site and yard maintenance – such as road repair, drainage maintenance, and perimeter fence repair.²⁹⁵¹ PG&E developed its forecast based on Company targets aligned with operational and strategic changes to the portfolio.²⁹⁵²

Cal Advocates recommends a 2023 expense reduction of \$10.599 million based on a four-year average (2016-2019) of Facilities Management program costs adjusted for costs previously recorded as part of SFGO management’s costs.²⁹⁵³

²⁹⁴⁹ CALPA-10, p. 25, lines 4-5.

²⁹⁵⁰ PG&E-20-E, p. 5-7, line 23 to 5-7, line 10.

²⁹⁵¹ PG&E-20-E, p. 5-8, lines 19-27.

²⁹⁵² PG&E-20-E, p. 5-9, lines 6-8.

²⁹⁵³ CALPA-10, p. 22, lines 7-10.

Cal Advocates' recommendation is flawed for two reasons. First, the four-year average (2016-2019) used by Cal Advocates is not representative of PG&E's Facility Management program costs going forward. Cal Advocates' recommendation does not account for the many recent changes to PG&E's facilities and would be insufficient to operate and maintain these facilities in a post-pandemic environment or to support current operations when all PG&E's offices fully reopen in August 2022.²⁹⁵⁴ Second, Cal Advocates' adjustment for the costs previously recorded as part of SFGO management's cost²⁹⁵⁵ incorrectly assumes that all SFGO forecast operating expenses are no longer needed and should be reflected as a credit. Cal Advocates' recommended funding level is inadequate to meet PG&E's commitments to continue to operate portions of SFGO through 2023 to maintain critical operations during transition to other sites, and to maintain back-office operations such as mail services until transitioned to Oakland.²⁹⁵⁶

7.6.2 Line Of Business Wildfire Mitigation Support (MWC IG)

The LOB Wildfire Mitigation Support program captures costs to support materials and equipment, office and yard space, and increased headcount to directly support wildfire mitigation initiatives such as systems inspection, grid hardening, emergency generation, and other initiatives directly related to mitigating catastrophic wildfires.²⁹⁵⁷

PG&E forecast \$1.1 million for MWC IG. Cal Advocates recommends no funding for this MWC as indicated in Table 7-7 below.²⁹⁵⁸

²⁹⁵⁴ PG&E-20-E, p. 5-9, lines 14-18 and lines 25-28.

²⁹⁵⁵ CALPA-10, p. 22, lines 9-10.

²⁹⁵⁶ PG&E-20-E, p. 5-9, lines 19-22 and p. 5-9, line 28 to 5-10, line 3.

²⁹⁵⁷ PG&E-20-E, p. 5-10, lines 7-11.

²⁹⁵⁸ PG&E-20-E, p. 5-3, Table 5-1, line 3.

TABLE 7-7
LINE OF BUSINESS WILDFIRE MITIGATION SUPPORT (MWC IG)
PG&E'S EXPENSE FORECAST AND RECOMMENDED REDUCTIONS (\$000s)^(a)

Party	2020 Rec.	2021	2022	2023
PG&E	\$545	\$1,000	\$1,100	\$1,100
Cal Advocates				\$(1,100)
(a) PG&E-20, p. 5-22, Table 5-4, line 3; PG&E-64, p. JCE 7-37 (Cal Advocates' recommendation)				

Cal Advocates asserts that amounts already assigned to a memorandum account are not to be forecasted in a GRC but recorded to the Fire Risk Mitigation Memorandum Account (FRMMA) when incurred and subjected to a reasonableness review.²⁹⁵⁹ Cal Advocates' recommendation should not be adopted. The wildfire mitigation costs forecasted in this program are continuing costs to help mitigate the risk of wildfire and thus should be approved under traditional GRC forecast ratemaking principles. The costs were previously recorded in the FRMMA because they were unknown at the time PG&E filed the 2020 GRC. Now that these ongoing costs can be forecast, they should be included in GRC rates. The fact that there is a memorandum account where these costs have been recorded previously does not support continued memorandum account treatment for these forecastable costs.²⁹⁶⁰ The Commission has made clear in its numerous decisions approving the establishment of memorandum accounts that the inability to forecast costs in a GRC is one of the pre-requisites to its approval of tracking costs in a memorandum account.²⁹⁶¹ Where costs can be forecast in the GRC, there is no need to track them in a memorandum account. The Commission should adopt PG&E's proposal to forecast these costs on an ongoing basis.

7.6.3 Implement Real Estate Strategy (MWC JH)

Implement Real Estate Strategy provides strategic portfolio and financial planning and governance, real asset development, planning, design, delivery services, and other activities to

²⁹⁵⁹ CALPA-10, p. 25, lines 22-24.

²⁹⁶⁰ PG&E-20-E, p. 5-10, line 24 to p. 5-11, line 3.

²⁹⁶¹ D.19-09-026, p. 6. See also, D.20-05-042, p. 6.

maintain PG&E’s workspaces in compliance with local codes, standards, and ordinances. The specific project pertains to moving employees out of the San Ramon Bishop Ranch BR1Y leased office space and restoring the building to return to the landlord.²⁹⁶²

PG&E’s initial forecast for MWC JH was \$7.787 million. Cal Advocates recommended a reduction of \$1.176 million based on a forecasting error. After reviewing Cal Advocates’ testimony, we agreed and indicated that we would correct the error identified by Cal Advocates’ and reduced our forecast by \$1.176 million.²⁹⁶³

The Commission should approve a forecast of \$6.611 million for MWC JH as agreed upon by PG&E and Cal Advocates.

7.6.4 Building Services Overhead Credit (MWC ZC)

The Building Services Overhead Credit represents the offsetting credit as the Building Services overhead is applied (debited) to applicable capital and balancing account expense projects.²⁹⁶⁴ PG&E forecast \$(62.171) million for MWC ZC. Cal Advocates recommends a reduction of \$4.384 million as indicated in Table 7-8 below.²⁹⁶⁵

**TABLE 7-8
BUILDING SERVICES OVERHEAD CREDIT (MWC ZC):
PG&E’S EXPENSE FORECAST AND
PARTIES RECOMMENDED REDUCTIONS (\$000s)^(a)**

Party	2020 Rec.	2021	2022	2023
PG&E	\$(63,557)	\$(68,579)	\$(68,476)	\$(62,171)
Cal Advocates				\$(4,384)
(a) PG&E-20, p. 5-22, Table 5-4, line 8; PG&E-64, p. JCE 7-40 (Cal Advocates’ recommendation)				

To calculate the overhead credit forecast, PG&E uses three years (2017-2019) of recorded data. Use of this recorded data provides a historical reference without going too far

²⁹⁶² PG&E-20-E, p. 5-11, lines 6-13.

²⁹⁶³ PG&E-20-E, p. 5-3, Table 5-1, line 4.

²⁹⁶⁴ PG&E-20-E, p. 5-12, lines 8-10.

²⁹⁶⁵ PG&E-20-E, p. 5-3, Table 5-1, line 8.

back to miss incorporating any changes to the business (i.e., wildfire support, system hardening, etc.). PG&E's forecast was further adjusted to lower the credit because PG&E will stop applying this overhead credit to almost all balancing account expense orders.²⁹⁶⁶

Cal Advocates recommends using five years of data (2016-2020) to develop the test year forecast,²⁹⁶⁷ as opposed to PG&E's use of three years of data (2017-2019).²⁹⁶⁸ Cal Advocates acknowledges PG&E's cost model change in 2023, but considers the addition of more years of data a reasonable proxy.

Cal Advocates' proposal is not reasonable. Basing a forecast on five years of historical data instead of three fails to account for the cost model changes PG&E proposes to implement in 2023, which will fundamentally change the composition of the overhead allocation. Simply put, there is not five years of data available under the 2020 GRC cost model changes and 2023 proposed cost model changes for Cal Advocates proposed methodology to work.²⁹⁶⁹ PG&E has accounted for this cost model change in its forecast, which should be adopted.²⁹⁷⁰

7.6.5 Implement Real Estate Strategy (MWC 23)

Implement Real Estate Strategy provides strategic portfolio planning, real asset development, design, and project delivery services.²⁹⁷¹ PG&E forecasts \$1,007.521 million in 2023, \$141.3 million in 2024, \$139.0 million in 2025, and \$130.0 million in 2026 for MWC 23. Cal Advocates recommends a reduction of \$917.0 million in 2023. AARP recommends

²⁹⁶⁶ PG&E-20-E, p. 5-12, lines 21-27.

²⁹⁶⁷ CALPA-10, p. 27, lines 22-23.

²⁹⁶⁸ CALPA-10, p. 28, lines 25-26.

²⁹⁶⁹ See Section 7.3.3.1 above for additional discussion.

²⁹⁷⁰ PG&E-20-E, p. 5-13, lines 11-18.

²⁹⁷¹ PG&E-20-E, p. 5-13, lines 21-22.

reductions of \$921.0 million in 2023, \$29.0 million in 2024, \$47.5 million in 2025, and \$37.0 million in 2026.²⁹⁷²

TABLE 7-9
IMPLEMENT REAL ESTATE STRATEGY (MWC 23)
PG&E'S CAPITAL FORECAST AND
PARTIES RECOMMENDED REDUCTIONS (\$000s)^(a)

Party	2020 Rec.	2021		2022	2023	2024	2025	2026
PG&E	\$177,880	\$151,733		\$152,442	\$1,007,521	\$141,300	\$139,000	\$130,000
Cal Advocates					\$(917,000)			
AARP					\$(921,000)	\$(29,000)	\$(47,500)	\$(37,000)
(a) PG&E-20, p. 5-22, Table 5-5, line 2; PG&E-20, p. 5-4, Table 5-2, line 2 (Parties' recommendations).								

Cal Advocates' and AARP's proposed reductions are related to: (1) PG&E's SFGO/Lakeside Project; (2) the Aviation Center Project; and (3) security fencing at service centers. These issues are addressed below.

7.6.5.1 SFGO/Oakland Lakeside Project

In 2020, PG&E developed and obtained Commission approval of a plan to sell the SFGO complex and enter into a lease with an option to purchase 300 Lakeside in Oakland.²⁹⁷³ Cal Advocates proposes to exclude all of the \$892 million purchase price of the Oakland/Lakeside Property, and any related transition costs from PG&E's 2023 capital forecast.²⁹⁷⁴ Cal Advocates does not oppose the purchase but recommends that the purchase price be recorded in a memorandum account along with other costs associated with the transition and move to the Oakland Lakeside property, and that these amounts be subject to additional review. AARP opposes the purchase of the property and recommends leasing instead of purchasing.²⁹⁷⁵

²⁹⁷² PG&E-20-E, p. 5-4, Table 5-2, line 2.

²⁹⁷³ PG&E-07, p. 5-14, lines 25-28.

²⁹⁷⁴ CALPA-10, p. 33, lines 2-3.

²⁹⁷⁵ AARP-01, p. 58, lines 10-11.

The Cal Advocates and AARP recommendations conflict with the Commission's decision approving the 300 Lakeside transaction, which found reasonable the following provision:

PG&E's headquarters real estate strategy is prudent and reasonable. In particular, the SFGO sale, the SFGO interim leaseback, Lakeside building lease and option to purchase and anticipated exercise of that purchase option, and movement of PG&E's headquarters to Oakland in 2022-2023 are all reasonable.²⁹⁷⁶

The Commission has already determined that either lease or purchase are reasonable; AARP's argument that PG&E should lease rather than purchase 300 Lakeside is moot.²⁹⁷⁷ Cal Advocates' argument that the capital costs of the purchase should be included in rates only after additional review and approval is similarly precluded by the Commission's approval of the settlement, which includes the following provision:

The Settling parties agree that the terms of the Lakeside Building Lease and Purchase Option Agreement, including the Lakeside building purchase price and [various other costs] are just and reasonable, and are eligible to be placed into rates subject to true-up in the Petition for Modification process.

If the purchase price were not included in rates already, there would be nothing to true up. While certain costs associated with the SFGO sale and Lakeside transition are to be recorded in a memorandum account, these do not include the initial purchase price of \$892 million, which is known and which PG&E expressly indicated would be included in its capital forecast in the 2023 GRC.²⁹⁷⁸ The costs to be recorded in the memorandum account are identified as the costs associated with *moving* expenses, not the purchase price.²⁹⁷⁹

²⁹⁷⁶ PG&E-20-E, p. 5-15, lines 19-23.

²⁹⁷⁷ D.21-08-027.

²⁹⁷⁸ PG&E-20-E, p. 5-16, lines 16-17.

²⁹⁷⁹ D.21-08-027, p. 38, FOF 12.

The Commission should approve PG&E's capital forecast, including the \$892 million purchase price, as previously approved by the Commission. Cal Advocates and AARP's belated attempts to modify the terms of the settlement and decision regarding ratemaking for the Oakland purchase should be rejected.

7.6.5.2 Aviation Operation Center

To support Aviation Services operations and to reduce operating expense from lease aviation properties, PG&E plans to develop an Aviation Operations Center (AOC). This project includes the development of a centralized aviation operations center adjacent to one of Northern California's regional public airports and a drone operations and maintenance facility.²⁹⁸⁰ The AOC will support PG&E fixed wing, helicopter, and drone fleets with asset storage, light maintenance and office spaces for Aviation Services personnel, including dispatch.²⁹⁸¹ Developing an AOC supports a longer-term goal of Aviation Services to develop a centralized fleet and support operations center which would provide the following:

- Weather optimization for aviation operations, allowing Aviation to operate more regularly under a set of regulations. This form of flight decrease flight risks and allows for more opportunities to fly, providing ideal meteorological conditions.
- Align with creating an in-house helicopter maintenance program to improve heavy-lift availability, controls and oversight for Wildfire Mitigation Operations, a centralized location for all assets' maintenance operations
- Coordination, accessibility, accountability, consistent availability of materials (i.e., maintenance, human external ropes, central warehouse for job materials).²⁹⁸²

By developing the AOC adjacent to an existing public airport, PG&E will leverage existing runway, taxiway and other aspects of the regulated airport. Cal Advocates opposes PG&E's estimate of \$25 million for this project, asserting that "the operational date is uncertain

²⁹⁸⁰ PG&E-20-E, p. 5-18, lines 11-13.

²⁹⁸¹ PG&E-07, WP 5-153.

²⁹⁸² PG&E-07, WP 5-153.

and any savings are not fully defined,” and PG&E had not purchased a site as of February 2022.²⁹⁸³

Cal Advocates’ recommended reduction is misplaced. Cal Advocates states that its primary reason for not including the \$25 million project is that it is unlikely that the project will be initiated soon enough to require these capital expenditures in 2023 because land for the project has not been purchased.²⁹⁸⁴ However, the property acquisition for the AOC will be a land lease, not a land purchase, as the project must be on-airport, and airports are county-owned property. The capital requirement is based on the program’s proposed operations and hangar space. Therefore, Cal Advocates errs in assuming that the AOC project cannot be completed in 2023 consistent with PG&E’s GRC forecast.²⁹⁸⁵ In addition, Cal Advocates’ secondary claim that the project should not be funded because PG&E cannot concretely demonstrate future cost savings is a red herring; PG&E has stated that the reason it is pursuing centralized aviation operation is not solely to reduce operating expense, but also to increase operational efficiencies, safety, and compliance.²⁹⁸⁶

Cal Advocates’ recommended reductions for the AOC project are based on erroneous assumptions and must be rejected. This capital project supports current and future necessary aviation services and PG&E’s estimate of \$25 million should be adopted.

7.6.5.3 Service Center Security Fencing Program

The Service Center Security Fencing program will enhance perimeter security and fencing to reduce threat of physical attack and/or criminal trespass by ensuring perimeter

²⁹⁸³ CALPA-10, p. 37, lines 9-24.

²⁹⁸⁴ CALPA-10, p. 39, lines 7-10.

²⁹⁸⁵ PG&E-20-E, p. 5-19, lines 7-15.

²⁹⁸⁶ PG&E-20-E, p. 5-19, lines 16-23.

security and access control systems and features are compliant with PG&E's Corporate Security standards.²⁹⁸⁷

AARP proposes a 2023-2026 capital reduction of \$9.0 million per year based on its claim that the Corporate Security standard requiring new facility fencing is an arbitrary change in PG&E standards meant to justify rate increases. AARP also claims that increases in standards are not always based on actual risk data.²⁹⁸⁸

AARP's recommendation is unsupported. The RAMP risk of Physical Attack is described in CRESS's RAMP testimony and justifies the need for increased security at PG&E's facilities.²⁹⁸⁹ As shown in PG&E's opening testimony, the frequency of risk of physical attack is second only to a seismic occurrence and could result in significant damage including potential loss of life and financial loss.²⁹⁹⁰ PG&E's investment in enhancing/upgrading perimeter security directly reduces the RAMP risk of physical attack and is a prudent investment to mitigate loss.

PG&E's Corporate Real Estate team works closely with the PG&E Corporate Security team to identify priority sites. A focused approach to identify locations as candidates for updating perimeter security to enhanced standards started in 2018. The site priority was based on (a) age of facility; (b) current state of perimeter fencing; (c) recent history of criminal trespass; and (d) extent of planned operations at the respective site. PG&E is focusing this investment on the highest priority yards based on age and condition along with activity levels to continue safe delivery of energy to customers. PG&E's sole intent is to mitigate or eliminate criminal trespass onto our sites to protect our coworkers and eliminate theft of materials and

²⁹⁸⁷ PG&E-20-E, p. 5-19, line 26 to p. 5-20, line 4.

²⁹⁸⁸ AARP-01, p. 61, lines 5-18.

²⁹⁸⁹ PG&E-07, p. 5-30, Table 5-6.

²⁹⁹⁰ PG&E-07, p. 5-30, Table 5-6.

equipment.²⁹⁹¹ PG&E has provided ample support for its forecasts while AARP's proposes a reduction based on inaccurate speculation, ignoring PG&E's testimony. The Commission should adopt PG&E's forecast.

7.7 Land and Environmental Management

The Land and Environmental Management (LEM) organization manages and implements PG&E's compliance with environmental laws and regulations, including oversight of PG&E's expansive land holdings, protection of sensitive species and natural and cultural resources, remediation of contamination from historic operations, monitor emerging regulatory trends and implement Shared Services risk and compliance programs.²⁹⁹²

PG&E's TY 2023 expense forecast as reflected in opening testimony is \$29.088 million.²⁹⁹³ PG&E's TY 2023 forecast in the JCE is \$32.160 million.²⁹⁹⁴ PG&E's expense forecast is tracked in twelve MWCs and is undisputed, as reflected in Appendix A.

PG&E capital expenditures forecast as reflected in opening testimony is \$12.017 million in 2021, \$7.617 million in 2022, \$7.617 million in 2023, \$7.167 million in 2024, \$7.617 million in 2025, and \$7.617 million in 2026.²⁹⁹⁵ PG&E's capital expenditures forecast in the JCE is \$12.384 million in 2021, \$8.884 million in 2022, \$9.218 million in 2023, \$9.231 million in 2024, \$9.112 million in 2025, and \$8.995 million in 2026.²⁹⁹⁶ PG&E's capital forecast is tracked in MWC 05, Tools and Equipment, and in MWC 12, Implement Environmental Projects, and is also undisputed. The expense and capital forecasts for LEM are reasonable and should be adopted.

²⁹⁹¹ PG&E-20-E, p. 5-20, line 27 to p. 5-21, line 7.

²⁹⁹² PG&E-07, p. 6-4, lines 2-9.

²⁹⁹³ PG&E-07, p. 6-33, Table 6-12, line 15.

²⁹⁹⁴ PG&E-64, p. 3-5, Table 3A-1, lines 184-195.

²⁹⁹⁵ PG&E-07, p. 6-34, Table 6-13, line 4.

²⁹⁹⁶ PG&E-67, WP-4; PG&E-07, Ch. 6, MWCs 05, 12 and 2F.

7.8 Enterprise Records And Information Management And Enterprise Data Management

The Enterprise Records and Information Management (ERIM) program focuses on reducing risks and increasing trust in the company's records and information by providing clear governance, change management and process improvement, and effective technology and tools.

The newly proposed Enterprise Data Management (EDM) program focuses on ensuring the quality and usefulness of PG&E's data assets to support effective data-driven decision making. The EDM program treats data as an asset, which translates into defining, implementing, and monitoring requirements to identify and catalog critical data assets, measure the quality and accuracy of those assets, and mitigate risks to those assets as needed so that they are trusted and useful to support decision-making. Moreover, the EDM program strives to promote more consistent data management and data management standard compliance across the lines of business to improve operational efficiency.²⁹⁹⁷

PG&E's TY 2023 expense forecast as reflected in rebuttal testimony for ERIM and EDM is \$20.328 million.²⁹⁹⁸ PG&E's TY 2023 forecast in the JCE is \$20.780.²⁹⁹⁹

PG&E capital expenditures forecast as reflected in rebuttal testimony is \$2.720 million in 2021, \$2.0 million in 2022, \$2.0 million in 2023, \$2.0 million in 2024, \$2.0 million in 2025, and \$2.0 million in 2026.³⁰⁰⁰ PG&E's capital expenditures forecast in the JCE is \$2.803 million in 2021, \$2.322 million in 2022, \$2.420 million in 2023, \$2.424 million in 2024, \$2.392 million in 2025, and \$2.362 million in 2026.³⁰⁰¹ PG&E's capital forecast is tracked in two MWCs: MWC 2F, Build IT Applications and Infrastructure; and MWC 21, Miscellaneous Capital. PG&E's capital forecast is undisputed, as indicated in Appendix A.

²⁹⁹⁷ PG&E-07, p. 7-1, lines, 13-29.

²⁹⁹⁸ PG&E-20-E, p. 7-3, Table 7-1, line 4.

²⁹⁹⁹ PG&E-64, p. 3-5, Table 3A-1, lines 196-197.

³⁰⁰⁰ PG&E-20-E, p. 7-8, Table 7-5, line 2.

³⁰⁰¹ PG&E-67, WP-4; PG&E-07, Ch. 7, MWCs 05, 21 and 2F.

The remainder of this section addresses the only disputed expense forecast for PG&E's EDM program.

7.8.1 EDM Program (MWC AB)

PG&E established the EDM Governance Chief role in March 2020 to oversee the ways the Company views and manages data.³⁰⁰² In 2021, PG&E operationalized the EDM organization as a centralized function providing enterprise level strategy and support for maturing data management.³⁰⁰³ The EDM program reflects PG&E's re-thinking of data as an asset that needs to be managed.³⁰⁰⁴

The EDM organization will have the following departments and associated responsibilities:

- Data Governance and Oversight – responsible for developing, implementing, maintaining, and monitoring adherence to EDM policy and standards. Focuses on establishing organizational roles and responsibilities, policies, processes, procedures, and standards to ensure the appropriate data quality and accessibility is maintained through the complete lifecycle of the data.
- Data Stewardship – responsible for providing assessment, training, and education to PG&E leaders, who are each responsible for promoting consistent data management. Activities include identifying, prioritizing, and resolving cross-LOB data management related issues and developing, implementing, and maintaining data literacy and data stewardship programs.
- Project Execution – responsible for executing high level cross functional data quality improvement projects
- Program Strategy and Delivery – responsible for developing the long term EDM roadmap, implementation plan and oversight to further data management maturity as well as change management and communication strategies and other administrative actions to drive program success.³⁰⁰⁵

³⁰⁰² PG&E-7, p. 7-10, lines 4-8.

³⁰⁰³ PG&E-07, p. 7-10, lines 9-11.

³⁰⁰⁴ PG&E-07, p. 7-30, lines 4-14.

³⁰⁰⁵ PG&E-07, p. 7-31 line 16 to p. 7-32, line 10.

PG&E forecast \$3.8 million for the new EDM program.³⁰⁰⁶ Cal Advocates opposed all funding for the EDM program.³⁰⁰⁷ The parties' original positions are summarized in Table 7-10 below.

TABLE 7-10
ENTERPRISE DATA MANAGEMENT PROGRAM (MWC AB)
PG&E'S EXPENSE FORECAST AND
PARTIES RECOMMENDED REDUCTIONS (\$000s)^(a)

Party	2020 Rec.	2021	2022	2023
PG&E	\$--	\$--	\$--	\$3,800
Cal Advocates				\$(3,800)
(a) PG&E-20, p. 7-8, Table 7-4, line 2; PG&E-64, p. JCE 7-56 (Cal Advocates' recommendation)				

As part of the EDM/IT Stipulation, Cal Advocates and TURN have agreed to adopt PG&E's forecast of \$3.8 million to fully fund the EDM program. Table 7-11 shows the agreed-upon EDM program forecast.

TABLE 7-11
STIPULATED ENTERPRISE DATA MANAGEMENT PROGRAM (MWC AB)
PG&E'S EXPENSE FORECAST
(\$000s)^(a)

Party	2023
PG&E Original Forecast	\$3,800
Cal Advocates Recommended Reduction	\$(3,800)
Joint Recommended Reduction	\$0
Total Adjusted Forecast	\$3,800
(a) PG&E-20, p. 7-8, line 2; PG&E-64, p. JCE 7-56 (Cal Advocates' recommendation)	

The Commission should adopt the agreed-upon forecast for the EDM program. No other parties oppose the forecast. This outcome is fully supported by evidence in the record as described in more detail in Chapter 7 of PG&E's Exhibits 7 and 20.

7.9 Information Technology

PG&E's Information Technology or IT group provides a critical foundation for PG&E's day-to-day activities, including work execution, grid control, customer support, emergency

³⁰⁰⁶ PG&E-20-E, p. 7-3, Table 7-1, Line 2.

³⁰⁰⁷ CALPA-10, p. 41, lines 21-24.

response, and asset management. The IT forecast is comprised of capital and expense that will enable PG&E to finance third-party contracts, migrate applications to the commercial cloud, maintain software tools used by field crews and back-office personnel, mitigate asset failure, and deliver technology solutions.

PG&E's TY 2023 expense forecast as reflected in rebuttal testimony is \$385.094 million.³⁰⁰⁸ PG&E's TY 2023 forecast in the JCE is \$402.310 million.³⁰⁰⁹

PG&E capital expenditures forecast as reflected in rebuttal testimony is \$191.570 million in 2021, \$204.100 million in 2022, \$265.900 million in 2023, \$279.900 million in 2024, \$305.500 million in 2025, and \$293.400 million in 2026.³⁰¹⁰ PG&E's capital expenditures forecast in the JCE is \$197.416 million in 2021, \$236.986 million in 2022, \$321.775 million in 2023, \$339.201 million in 2024, \$365.447 million in 2025, and \$346.498 million in 2026.³⁰¹¹

As part of the EDM/IT Stipulation, Cal Advocates, TURN, and PG&E have agreed to a \$42 million reduction to PG&E's expense forecast for MWC JV. MWC JV includes expense forecast for Baseline Operations and Management; Technology Investments: Solution Delivery and Operations; and Technology Investments: Field Work Management, Data Enablement, and Enterprise Resource Management. PG&E's forecast for all of MWC JV was \$420.375 million. Cal Advocates recommended a total reduction of \$80.947 million, and TURN recommended a \$35.5 million reduction. The agreed-upon forecast for all of MWC JV is reflected in Table 7-12:

³⁰⁰⁸ PG&E-20-E, p. 8-3, Table 8-1, line 13.

³⁰⁰⁹ PG&E-64, p. 3-5, Table 3A-1, lines 198-200.

³⁰¹⁰ PG&E-20-E, p. 8-36, Table 8-5, line 2.

³⁰¹¹ PG&E-67, WP-4; PG&E-07, Ch. 8, MWC 2F.

TABLE 7-12
STIPULATED BASELINE O&M NON-LABOR/VARIOUS TECHNOLOGY INVESTMENTS
(MWC JV)
PG&E'S EXPENSE FORECAST
(\$000s)^(a)

Party	2023
PG&E Original Forecast	\$420,375
Cal Advocates' Recommended Reduction	\$(80,947)
TURN Recommended Reduction	\$(35,500)
Joint Recommended Reduction	\$(42,000)
Total Adjusted Forecast	\$378,375
(a) PG&E-20, p. 8-35, Table 8-4, line 2; PG&E-64, p. JCE 7-60 (Parties' recommendation)	

The Commission should adopt the agreed-upon \$378.375 million adjusted forecast. This outcome is fully supported by record evidence as described in more detail in Chapter 8 of PG&E's Exhibits 7 and 20.

Also as part of the EDM/IT Stipulation, Cal Advocates, TURN, and PG&E have agreed to a \$6 million reduction to PG&E's 2023 capital forecast for MWC 2F. MWC 2F includes capital forecast for Technology Investments: Core Network Infrastructure and Operations; and Technology Investments Portfolio Capital. PG&E's forecast for MWC 2F was \$265.9 million for 2023; \$279.9 million for 2024; \$305.5 million for 2025; and \$293.4 million for 2026. Cal Advocates recommended a \$58.9 million reduction to 2024, and TURN recommended a \$54.935 million reduction to 2023; a \$58.296 million reduction to 2024; a \$60.529 million reduction to 2025; and a \$58.271 million reduction to 2026. The agreed-upon forecast is reflected in Table 7-13:

TABLE 7-13
STIPULATED TECHNOLOGY INVESTMENTS CAPITAL PORTFOLIO (MWC 2F)
PG&E'S EXPENSE FORECAST
(\$000s)^(a)

Party	2020 Rec.	2021	2022	2023	2024	2025	2026
PG&E Original Forecast	\$185,498	\$191,570	\$204,100	\$265,900	\$279,900	\$305,500	\$293,400
Cal Advocates Recommended Reduction				\$(58,900)			
TURN Recommended Reduction				\$(54,935)	\$(58,296)	\$(60,529)	\$(58,271)
Joint Recommended Reduction				\$(6,000)	\$(6,000)	\$(6,000)	\$(6,000)
Total Adjusted Forecast				\$259,900	\$273,900	\$299,500	\$287,400

(a) PG&E-20, p. 8-36, Table 8-5, line 1; PG&E-20, p. 8-4, Table 8-2, line 4 (Parties' recommendation)
(b) Assumes that escalation will be applied to the Joint Recommended Reduction at the rate that is approved in the proceeding.

The Commission should adopt the agreed-upon \$259.9 million adjusted forecast for 2023; the \$279.9 million adjusted forecast for 2024; the \$305.5 million adjusted forecast for 2025; and the \$293.4 million adjusted forecast for 2026 (with escalation applied to the Joint Recommended Reduction for years 2024-2026). This outcome is fully supported by evidence in the record as described in more detail in Chapter 8 of PG&E's Exhibits 7 and 20.

The remainder of this section addresses disputed expense and capital forecast items by MWC.

7.9.1 Baseline O&M Non-Labor (MWC JV)

The Non-Labor O&M program primarily refers to recurring, contractual costs related to third-party IT products, services, and support.³⁰¹² Major costs include fixed-fee O&M managed service contracts, vendor maintenance and support agreements, software licenses, commercial cloud service subscriptions, and telecom leases and usage costs.³⁰¹³ Cost increases in this program primarily address post-deployment O&M for new technology investments, growth in users and usage of existing solutions, and standard escalation.³⁰¹⁴

PG&E forecast \$236.775 million for Baseline O&M Non-Labor. Cal Advocates recommended a reduction of \$38.424 million.³⁰¹⁵ TURN recommended a reduction of \$35.5 million.³⁰¹⁶ The parties' original positions are summarized in Table 7-14 below:

³⁰¹² PG&E-20-E, p. 8-5, lines 19-20.

³⁰¹³ PG&E-20-E, p. 8-5, lines 20-23.

³⁰¹⁴ PG&E-20-E, p. 8-5, lines 19-25.

³⁰¹⁵ CALPA-10, p. 51, lines 12-15.

³⁰¹⁶ TURN-15, p. 18, line 9 to p. 20, line 1.

TABLE 7-14
BASELINE O&M NON-LABOR (MWC JV)
PG&E'S EXPENSE FORECAST AND
PARTIES RECOMMENDED REDUCTIONS (\$000s)^(a)

Party	2020 Rec.	2021	2022	2023
PG&E	\$311,365	\$311,545	\$342,775	\$420,375
Cal Advocates				\$(80,947)
TURN				\$(35,500)
(a) PG&E-20, p. 8-35, Table 8-4, line 2; PG&E-64, p. JCE 7-60 (Parties' recommendation)				

The Non-Labor O&M program is among those in MWC JV that are subject to the EDM/IT Stipulation, pursuant to which PG&E, Cal Advocates, and TURN have agreed to a total forecast for MWC JV as described above.

7.9.2 Technology Investments: Solution Delivery And Operations (MWC JV)

The Solution Delivery and Operations program invests in the foundational software and IT infrastructure within PG&E-owned data centers, PG&E field sites, and third-party commercial cloud environments that enable PG&E to deliver and operate reliable IT solutions, which include more than 1,300 enterprise and customer-facing software applications.³⁰¹⁷ Key investments include work to mitigate IT asset failure risk by migrating applications to the commercial cloud and modernizing end-of-life application components, data center infrastructure, and foundational services.³⁰¹⁸ Expense increases in this program primarily relate to PG&E's use of commercial cloud services, which require more expense-centric accounting under standard accounting principles than traditional asset investments.³⁰¹⁹

PG&E forecast \$26.9 million for Technology Investments: Solution Delivery and Operations. Cal Advocates recommended a reduction of \$24.304.³⁰²⁰

³⁰¹⁷ PG&E-20-E, p. 8-12, lines 16-20.

³⁰¹⁸ PG&E-20-E, p. 8-12, lines 20-26.

³⁰¹⁹ PG&E-20-E, p. 8-12, lines 16-26.

³⁰²⁰ CALPA-10, p. 62, lines 2-4.

The Solution Delivery and Operations program is among those in MWC JV that are subject to the EDM/IT Stipulation, pursuant to which PG&E, Cal Advocates, and TURN have agreed to a total forecast for MWC JV as described above.

7.9.3 Technology Investments: Field Work Management, Data Enablement And Enterprise Resource Management (MWC JV)

The Field Work Management program includes investment in software tools used by field crews and back-office personnel for asset inspection and maintenance; work planning, scheduling, and dispatch; managing work packages and construction documentation; locating and marking underground assets; and coordinating between field crews and control center operations.³⁰²¹ The Data Enablement program includes investments that directly support information management and data management initiatives and continue ongoing efforts to establish a foundational platform for data management and analytics use cases across the Company.³⁰²² The Enterprise Resource Management program continues efforts to modernize PG&E's central Enterprise Resource Planning platform, SAP, and its component modules, which are integral to many of the Company's core processes.³⁰²³ Key investments include upgrading and migrating PG&E's legacy, end-of-life SAP components to SAP's modern, cloud-based platform.³⁰²⁴ Expense increases in these programs primarily relate to the adoption and expansion of commercial cloud solutions.³⁰²⁵

³⁰²¹ PG&E-20-E, p. 8-21, lines 1-6.

³⁰²² PG&E-20-E, p. 8-21, lines 6-10.

³⁰²³ PG&E-20-E, p. 8-21, lines 10-13.

³⁰²⁴ PG&E-20-E, p. 8-21, lines 13-15.

³⁰²⁵ PG&E-20-E, p. 8-21, lines 1-17.

PG&E forecast \$26.9 million for Technology Investments: Field Work Management, Data Enablement and Enterprise Resource Management. Cal Advocates recommended a reduction of \$18.219 million.³⁰²⁶

The Field Work Management, Data Enablement and Enterprise Resource Management programs are among those in MWC JV that are subject to the EDM/IT Stipulation, pursuant to which PG&E, Cal Advocates, and TURN have agreed to a total forecast for MWC JV as described above.

7.9.4 Technology Investments: Core Network Infrastructure And Operations (MWC 2F)

The Core Network Infrastructure and Operations program invests in technology used to transport data across long distances (including fiber optic and microwave systems) to direct data traffic from its origin to its destination (including routers and switches), to deliver voice communications via radio and telephone, and to manage and monitor the telecommunication network services that enable PG&E users and technology systems to communicate.³⁰²⁷ Planned investments mitigate IT Asset Failure risk associated with critical Network Technologies assets by replacing end-of-life equipment and obsolete technologies, diversifying network connections to improve resilience, expanding capacity and coverage to meet demand, and improving network management and monitoring capabilities.³⁰²⁸

PG&E forecast \$114.9 million in 2023, \$120.6 million in 2024, \$125.2 million in 2025, and \$125.4 million in 2026 for Technology Investments: Solution Delivery and Operations. TURN recommended reductions of \$54.935 million in 2023, \$58.296 million in 2024, \$60.529 in 2025 and \$58.271 million in 2026.³⁰²⁹

³⁰²⁶ CALPA-10, p. 68, lines 17-18, p. 71, lines 23-24, and p. 75, lines 17-18.

³⁰²⁷ PG&E-20-E, p. 8-26, lines 22-28.

³⁰²⁸ PG&E-20-E, p. 8-26, line 22 to p. 8-27, line 1.

³⁰²⁹ PG&E-20-E, p. 8-4, Table 8-2, line 1.

The Core Network Infrastructure and Operations program is among those in MWC 2F that are subject to the EDM/IT Stipulation, pursuant to which PG&E, Cal Advocates, and TURN have agreed to a total forecast for MWC 2F as described above.

7.9.5 Technology Investments Portfolio Capital (MWC 2F)

The Technology Investment Portfolio encompasses a collection of programs that deliver technology solutions necessary to support Company operations, enable innovation, maintain reliable IT assets and services, and optimize the management of PG&E’s IT footprint and its associated risks. Programs within the Technology Investments portfolio include the Solution Delivery and Operations, Field Work Management, Data Enablement, Enterprise Resource Management, and Core Network Infrastructure and Operations programs described above, as well as programs related to Asset Management and Risk Analysis, End-User Experience and Operations, IT Asset and Service Management, System Operation and Control, and Meter Management and Operations.³⁰³⁰

PG&E’s technology investments capital forecast is \$265.9 million in 2023. Cal Advocates recommended a reduction of \$58.9 million.³⁰³¹ The parties’ original positions are summarized in Table 7-15 below:

**TABLE 7-15
TECHNOLOGY INVESTMENTS CAPITAL PORTFOLIO (MWC 2F)
PG&E’S CAPITAL FORECAST AND
PARTIES RECOMMENDED REDUCTIONS (\$000s)^(a)**

Party	2020 Rec.	2021	2022	2023	2024	2025	2026
PG&E	\$185,498	\$191,570	\$204,100	\$265,900	\$279,900	\$305,500	\$293,400
Cal Advocates				\$(58,900)			
(a) PG&E-20, p. 8-36, Table 8-5, line 1; PG&E-20, p. 8-4, Table 8-2, line 4 (Parties’ recommendations).							

³⁰³⁰ PG&E-20-E, p. 8-31, line 29 to p. 8-32, line 8.

³⁰³¹ PG&E-20-E, p. 8-4, Table 8-2, line 3.

The Technology Investment Portfolio is among those aspects of MWC 2F that are subject to the EDM/IT Stipulation, pursuant to which PG&E, Cal Advocates, and TURN have agreed to a total forecast for MWC 2F as described above.

7.10 Cyber and Corporate Security

The Cyber and Corporate Security organizations work together to address constant and evolving cybersecurity and physical risks to PG&E's workforce, critical infrastructure, information assets, customers and business operations.³⁰³² To maintain effective Cyber and Corporate Security programs, PG&E must continue to invest in resources that keep us ahead of threats. The expense and capital forecasts presented are needed to support this strategy, allowing continued investments to address evolving types of attacks and new operational technologies to support changing business needs.³⁰³³ The expense and capital expenditure forecasts described below are all undisputed, as indicated in Appendix A.

PG&E's cybersecurity TY 2023 expense forecast as reflected in opening testimony is \$32.284 million.³⁰³⁴ PG&E's TY 2023 forecast in the JCE is \$33.337 million.³⁰³⁵ PG&E's cybersecurity expense forecast is tracked in MWC JV, Maintain IT Applications and Infrastructure.

PG&E's corporate security TY 2023 expense forecast as reflected in opening testimony is \$23.869 million.³⁰³⁶ PG&E's TY 2023 forecast in the JCE is \$25.580 million,³⁰³⁷ PG&E's corporate security expense forecast is tracked in MWC KZ, Provide Risk and Security Services, and is also undisputed

³⁰³² PG&E-07, p. 9-1, lines 23-27.

³⁰³³ PG&E-07, p. 9-6, lines 16-21.

³⁰³⁴ PG&E-07, p. 9-37, Table 9-10, line 4.

³⁰³⁵ PG&E-64, p. 3-5, Table 3A-1, line 201.

³⁰³⁶ PG&E-07, p. 9-37, Table 9-11, line 2.

³⁰³⁷ PG&E-64, p. 3-5, Table 3A-1, line 202.

PG&E cybersecurity capital expenditures forecast as reflected in opening testimony is \$29.285 million in 2021, \$29.285 million in 2022, \$29.785 million in 2023, \$30.475 million in 2024, \$31.384 million in 2025, and \$32.548 million in 2026.³⁰³⁸ PG&E's capital expenditures forecast in the JCE is \$30.179 million in 2021, \$34.004 million in 2022, \$36.004 million in 2023, \$36.932 million in 2024, \$37.542 million in 2025, and \$38.438 million in 2026.³⁰³⁹ PG&E's capital forecast is tracked in MWC 2F, Build IT Applications and Infrastructure.

PG&E corporate security capital expenditures forecast as reflected in opening testimony is \$12.585 million in 2021, \$12.585 million in 2022, \$13.326 million in 2023, \$14.066 million in 2024, \$14.066 million in 2025, and \$14.488 million in 2026.³⁰⁴⁰ PG&E's capital expenditures forecast in the JCE is \$12.969 million in 2021, \$14.613 million in 2022, \$16.126 million in 2023, \$17.046 million in 2024, \$16.826 million in 2025, and \$17.110 million in 2026.³⁰⁴¹ PG&E's capital forecast is tracked in MWC 3N, Install/Replace Security.

7.11 Geosciences

Geosciences is responsible for managing PG&E's seismic program, which is comprised of the Diablo Canyon Power Plant Long Term Seismic Program (LTSP) and the Integrated Seismic Risk Management Program. The work conducted by Geosciences to evaluate seismic hazard and risk across the Company is critical to public and worker safety.³⁰⁴² The forecast in this GRC reflects the broadening responsibility of the Geoscience organization to support an enterprise-wide seismic safety program. Activities include:

- Maintaining Geosciences group for internal seismic expertise and program management;

3038 PG&E-07, p. 9-38, Table 9-12, line 2.

3039 PG&E-67, WP-4; PG&E-07, Ch. 9, MWC 2F.

3040 PG&E-07, p. 9-38, Table 9-13, line 2.

3041 PG&E-67, WP-4; PG&E-07, Ch. 9, MWC 3N.

3042 PG&E-07, p. 10-2, lines 23-24.

- Development and implementation of seismic hazard and risk models, including contract support;
- Grants to various public agencies laboratories, and academic institutions to conduct user-defined geologic, geophysical and engineering research of direct interest and impact to PG&E.³⁰⁴³

PG&E's TY 2023 expense forecast as reflected in opening testimony is \$5.274 million.³⁰⁴⁴ The primary driver for increases to the forecast is escalation – the expected general inflation for contracts, materials and other services or fees, and includes higher employee labor rates attributable to market labor rate increases.³⁰⁴⁵ PG&E's geosciences expense forecast is tracked in ten MWCs and is undisputed, as indicated in Appendix A.

7.12 Enterprise Risk Management

The Enterprise and Operational Risk Management (EORM) organization is responsible for implementation and governance of the EORM Program and, on a temporary basis, for governance and oversight of wildfire risk management. The EORM organization provides the lines of business with the tools, methods, and technical support to identify, evaluate, prioritize, mitigate, and monitor risk inherent in PG&E's operations.³⁰⁴⁶ PG&E's TY 2023 expense forecast for the EORM organization as reflected in rebuttal testimony is \$8.006 million.³⁰⁴⁷ PG&E's TY 2023 forecast in the JCE is \$8.297 million.³⁰⁴⁸ EORM expenses are tracked in MWC KZ.

Cal Advocates disputes PG&E's forecast for EORM and recommends the following reductions:

³⁰⁴³ PG&E-07, p. 10-13, line 29 to p. 10-14, line 3.

³⁰⁴⁴ PG&E-07, p. 10-14, Table 10-2.

³⁰⁴⁵ PG&E-07, p. 10-14, lines 4-7.

³⁰⁴⁶ PG&E-20-E, p. 11-4, lines 6-11.

³⁰⁴⁷ PG&E-20-E, p. 11-6, Table 11-2, line 2.

³⁰⁴⁸ PG&E-64, p. 3-5, Table 3A-1, line 203.

TABLE 7-16
ENTERPRISE RISK MANAGEMENT (MWC KZ)
PG&E’S EXPENSE FORECAST AND
PARTIES RECOMMENDED REDUCTIONS (\$000s)^(a)

Party	2020 Rec.	2021	2022	2023
PG&E	\$3,492	\$11,500	\$7,500	\$8,006
Cal Advocates				\$(4,003)
(a) PG&E-20, p. 11-6, Table 8-2, line 1; PG&E-64, p. JCE 7-68 (Cal Advocates’ recommendation)				

Cal Advocates’ proposal for a fifty percent reduction in the program forecast is based on its argument that there is a shareholder benefit from this program. Cal Advocates contends that EORM’s risk-management function contributes to shareholder value and that a portion of the organization cost is embedded in other elements of PG&E’s GRC request.³⁰⁴⁹ This proposed reduction is unreasonable. The EORM organization’s work is a reasonable cost of utility service that benefits PG&E’s customers. The EORM organization supports data-driven risk assessments by providing a consistent framework, tools, and risk management program oversight across the enterprise. Successful implementation of the framework, tools and program benefits customers by helping to lower the likelihood and/or severity of events with safety, reliability, or financial consequences for customers.³⁰⁵⁰

Notably, Cal Advocates does not challenge the reasonableness of PG&E’s forecast.³⁰⁵¹ Work that benefits PG&E’s customers often has a positive impact on PG&E’s overall business health, and can benefit PG&E Corporation’s shareholders as a result. This is not justification for denying funding for a prudent program backed by a reasonable forecast. The Commission should approve PG&E’s forecast for this work because it is reasonable, and the funding will achieve customer benefits.

Cal Advocates’ embedded cost argument is also incorrect. The scope and function of the EORM organization has expanded since the previous GRC and the forecast presented reflects the

3049 CALPA-10, p. 83, lines 20-24.

3050 PG&E-20-E, p. 11-4, line 23 to p. 11-5, line 1.

3051 CALPA-10, p. 83, lines 15-18.

additional functions as well as the portion of the EORM function transferred from the Risk and Audit program.³⁰⁵² The additional costs for new headcount are necessary for EORM to provide service to PG&E's customers and are reasonable for inclusion in customer rates for recovery. The activities supported by the headcount forecasted here are separate from those forecasted elsewhere in PG&E's GRC. Therefore, the costs for this work are separate from costs associated with other work forecasted in the GRC. This forecast is the only mechanism for providing adopted funding for this work. For these reasons, PG&E's forecast is reasonable and should be approved by the Commission.

³⁰⁵² PG&E-07, p. 11-1, lines 11-14, p. 11-7, line 24 to p. 11-8, line 16; PG&E-20-E, p. 11-5, line 23 to p. 11-6, line 9.

8. HUMAN RESOURCES (EXHIBIT PG&E-08)

PG&E's Human Resources (HR) organization seeks to attract, retain and engage a skilled and qualified workforce to meet our customers' needs. PG&E operates in an increasingly competitive labor market and HR continues to focus on workforce planning to understand and prepare for our future needs; offering a competitive package of cash compensation and benefits; overseeing our hiring and selection process to ensure it follows all legal requirements and supports our commitment to diversity; supporting employees at all stages of their careers; and providing them with developmental opportunities and the training necessary to perform their jobs safely and effectively.³⁰⁵³ PG&E's TY 2023 expense forecast as reflected in rebuttal testimony for Human Resources, which includes department costs, information technology costs, and companywide expenses, is \$1,029.2 million.³⁰⁵⁴ PG&E's TY 2023 forecast as reflected in the JCE (Exhibit PG&E-64) is \$1,034.6 million.³⁰⁵⁵

Department costs include labor, materials and outside services to support the day-to-day operations of each department. The 2023 department cost forecast is \$85.4 million.³⁰⁵⁶ This is approximately a 9% increase compared to 2020 recorded costs.³⁰⁵⁷ PG&E's JCE forecast is \$88.7 million.³⁰⁵⁸ The majority of the increase is due to labor escalation and the addition of 3 net full-time equivalent support HR Service Delivery and Inclusion and PG&E Academy.³⁰⁵⁹ PG&E's TY 2023 forecast for companywide expenses is \$944.5 million. The 2023 forecast is a \$259.0 million (approximately 38%) increase compared to 2020 recorded costs. PG&E's 2023

³⁰⁵³ PG&E-08, p. 1-1, lines 12-21.

³⁰⁵⁴ PG&E-64, p. 3-18, Table 3C-1, line 21 (Department Costs + IT: \$84.674M) and p. 3-19, Table, lines 40-70 (Companywide Expenses: \$944.494M) = \$1,029.168M).

³⁰⁵⁵ PG&E-64, p. 3-18, Table 3C-1, line 21 (Department Costs + IT: \$88.993M) and p. 3-19, Table, lines 40-70 (Companywide Expenses: \$945.628M) = \$1,034.621.

³⁰⁵⁶ PG&E-64, p. 3-18, Table 3C-1, line 1.

³⁰⁵⁷ PG&E-08, WP 1-3, line 6.

³⁰⁵⁸ PG&E-64, p. 3-18, Table 3C-1, line 21.

³⁰⁵⁹ PG&E-08, p. 1-2, lines 8-11.

forecast for companywide expenses as presented in the JCE is \$944.5 million.³⁰⁶⁰

Companywide expenses include PG&E's compensation and benefits programs. The major drivers of the 2023 test year forecast include forecast increases for the following programs: (1) \$142.3 million for Medical (Utility) expenses;³⁰⁶¹ (2) \$94.0 million for the Short-Term Incentive Plan (STIP) based primarily on labor escalation;³⁰⁶² and (3) \$10.9 million for the Workforce Transition Program.³⁰⁶³

PG&E's TY 2023 forecast for IT expenses is \$0.288 million.³⁰⁶⁴ The 2023 forecast is a \$0.296 million less than 2020 recorded costs.³⁰⁶⁵ PG&E's 2023 forecast for IT expenses as presented in the JCE is \$0.3 million.³⁰⁶⁶

PG&E capital expenditures forecast as reflected in rebuttal testimony is \$1.6 million in 2021, \$1.0 million in 2022, \$1.0 million in 2023, \$1.0 million in 2024, \$1.0 million in 2025 and \$1.0 million in 2026.³⁰⁶⁷ PG&E's capital expenditures forecast as reflected in the JCE is \$1.7 million in 2021, \$1.2 million in 2022, \$1.2 million in 2023, \$1.2 million in 2024, \$1.2 million in 2025 and \$1.2 million in 2026.³⁰⁶⁸ These capital costs are associated with information technology projects as well as other costs to support PG&E Academy training such as building maintenance and tools and equipment.

³⁰⁶⁰ PG&E-64, p. 3-19, Table 3C-1, lines 40-70.

³⁰⁶¹ PG&E-08, WP5 Vol I-11, line 5 (2023: \$535.8 minus 2020: \$393.5=\$142.3).

³⁰⁶² PG&E-08, WP 4-2, line 5 (2023: \$232.6 minus 2020: \$138.6 = \$94.0).

³⁰⁶³ PG&E-08, p. 3-1, lines 28-30.

³⁰⁶⁴ PG&E-64, p. 3-18, Table 3C-1, line 12.

³⁰⁶⁵ PG&E-08, p. 1-9, Table 1-3, line 5 (2023: \$288- \$584 = \$(296)).

³⁰⁶⁶ PG&E-64, p. 3-18, Table 3C-1, line 12.

³⁰⁶⁷ PG&E-08, p. 1-9, Table 1-4, line 4.

³⁰⁶⁸ PG&E-64, p. 3-16, Table 3B-3, Total Exhibit (PG&E-8) (2021); p. 3-12, Table 3B-2, Total Exhibit (PG&E-8) (2022); and p. 3-8, Table 3B-1, Total Exhibit (PG&E-8) (2023); PG&E-67, WP-4, line 8 Total (2024-2026).

PG&E's 2023 forecast for technology programs is \$288 thousand, which is a \$296 thousand decrease (approximately 51%) compared to 2020 recorded costs.³⁰⁶⁹ The following issues listed in Table 8-1 are in dispute in this exhibit:

**TABLE 8-1
ISSUES IN DISPUTE**

Brief Section: Department	Description	Forecast and Recommendation
Section 8.1: HR Solutions and Services	Department Costs – Labor and Contracts	Cal Advocates recommends a \$2.2 million reduction to PG&E forecast based on 5-year average for both labor and contracts.
Section 8.2: HR Service Delivery and Inclusion	Department Costs – Labor and Contracts	Cal Advocates recommends a \$2.3 million reduction to PG&E's forecast based on the use of a 5-year average for labor and 4-year average for contracts.
Section 8.2: HR Service Delivery and Inclusion	Workforce Transition: Severance	Cal Advocates recommends a \$6.7 million reduction based on the use of a 3-year average (2018-2020).
Section 8.2: HR Service Delivery and Inclusion	Workforce Transition: Outplacement	Cal Advocates recommends a \$0.08 million reduction based on the use of a 3-year average (2018-2020).
Section 8.2: HR Service Delivery and Inclusion	Tuition Refund	Cal Advocates recommends a \$0.91 million reduction to PG&E's forecast based on five-year average.
Section 8.3: Compensation	Utility/Corp: STIP Non-Officer	Cal Advocates and TURN recommend a \$140.5 million reduction to PG&E's forecast. Total proposed funding 37.5% of STIP at target.
Section 8.3: Compensation	Utility/Corp: STIP Officer	Cal Advocates and TURN recommend a \$4.8 million reduction to PG&E's forecast. Total proposed funding 37.5% of STIP at target.
Section 8.3: Compensation	Utility/Corp: Non-Qualified Plans	Cal Advocates recommends a \$1.9 million (50%) reduction. Cal Advocates indicates that it is not clear if PG&E adjusted its forecast, by 50%, consistent with Commission guidance.
Section 8.4: Employee Benefits	Department Costs – Labor and Contracts	Cal Advocates recommends a \$0.4 million reduction to PG&E forecast based on the use of a 5-year average for labor and 3-year (2018-2020) average for contracts.

³⁰⁶⁹ PG&E-08, p. 1-9, Table 1-3, line 5.

Brief Section: Department	Description	Forecast and Recommendation
Section 8.4: Employee Benefits	Utility/Corp: Medical	Cal Advocates recommends a \$100.2 million reduction to PG&E forecast based on the use of a 5-year average.
Section 8.4: Employee Benefits	Utility/Corp: Dental	Cal Advocates recommends a \$7.4 million reduction to PG&E forecast based on the use of a 5-year average.
Section 8.4: Employee Benefits	Utility/Corp: Retirement Savings Plan (401k)	Cal Advocates recommends a \$1.0 million reduction to PG&E forecast. The recommendation is based on escalating to 2020 recorded match by historic trend rate.
Section 8.4: Employee Benefits	Utility: Commuter Transit Program	Cal Advocates recommends a \$52 thousand reduction to PG&E forecast. This represents a 50% reduction to bring expense closer to 2020 actual.
Section 8.4: Employee Benefits	Utility: Employee Relocation Program	Cal Advocates recommends a \$ 1.7 million reduction to PG&E forecast based on the use of a 4-year average (2017 – 2020).
Section 8.5: PG&E Academy	Department Costs – Labor	Cal Advocates recommends a \$2.9 million reduction to PG&E forecast based on 5-year average for labor.

8.1 HR Solutions and Services

HR Solutions and Services provides support to company leaders, employees and in some cases retirees. It also leads the company’s workforce planning and knowledge transfer activities and provides support to all other HR departments.³⁰⁷⁰ As part of PG&E’s planning process, the HR Solutions and Services Department works with each line of business (LOB) to develop their workforce plans. The LOBs determine the workforce they will need to perform the required work, balancing use of contractors and third parties with PG&E employees. The HR Services team provides the LOBs information on their current workforce, including anticipated attrition over the planning period. These forecasts are then adjusted and updated as new or changed work priorities and funding levels are established.³⁰⁷¹

³⁰⁷⁰ PG&E-08, p. 2-6 line 1 to p. 2-7, line 15.

³⁰⁷¹ PG&E-08, p. 2-1, line 24 to p. 2-2, line 2.

One outcome of the workforce planning process is an employee headcount forecast. The employee headcount forecast is used to adjust the forecast for many of the HR-sponsored companywide expense programs (e.g., medical, dental, vision) up or down to reflect forecast plan participant changes. Table 8-2 shows the aggregate actual employee headcount and forecast from the end of year 2020 to the end of year 2026.³⁰⁷²

**TABLE 8-2:
PG&E END OF YEAR EMPLOYEE
HEADCOUNT ACTUAL AND FORECAST**

Line No.	Year	2020	2021	2022	2023	2024	2025	2026
1	Total Headcount	25,600	27,312	27,492	27,587	27,609	27,141	27,227

8.1.1 Department Costs

The department cost forecast reflects the activities of two teams: HR Solutions and HR Services.

The HR Solutions Department is led by a Vice President (VP), with one Senior Director, two Directors and two Managers leading the various functional areas and is composed of the following seven functions: (1) HR Solutions Immediate Office; (2) Benefits³⁰⁷³; (3) HR Reporting and Analytics; (4) Workforce Planning, Risk & Compliance; (5) HR Emergency Management Support; (6) HR Labor Relations and Operations; and (7) HR Project Management Office.³⁰⁷⁴

The HR Services Department is led by a Senior Director, with one Director and five Managers leading various functional areas and is composed of the following seven functions: (1) HR Service Immediate Office; (2) HR Solutions Center (HRSC); (3) HR Business Partners; (4) Job Bidding, Hiring Hall, and Testing; (5) Employee Relations; (6) Labor Relations Service

³⁰⁷² PG&E-08, p. 2-4, line 32 to p. 2-5, line 4.

³⁰⁷³ The Benefits forecast is discussed in Section 8.4 below.

³⁰⁷⁴ PG&E-08, p. 2-6, lines 1-14.

Center; and (7) HR Technology of Programs.³⁰⁷⁵ PG&E's TY 2023 expense forecast for department costs as reflected in rebuttal testimony is \$23.4 million.³⁰⁷⁶ The 2023 forecast is a \$1.9 million (approximately 9%) increase compared to 2020 recorded costs. The increase is primarily driven by labor escalation. The department forecasts no staffing increase for 2023.³⁰⁷⁷

Cal Advocates recommends a \$2.23 million reduction to the HR Solutions and Services Department costs, which includes a reduction of \$1.92 million for salaries and a reduction of \$0.311 million for outside services.³⁰⁷⁸ Cal Advocates contends that PG&E has not supported or adequately justified the increase in its forecast relative to the historical data and due to the variability of the historical data.³⁰⁷⁹ As such, Cal Advocates recommends the use of a 5-year average for salaries³⁰⁸⁰ and outside services.³⁰⁸¹ With respect to salaries, PG&E described the basis for the forecast increase compared to 2020 recorded costs was standard labor escalation.³⁰⁸² This point is undisputed. Cal Advocates proposed 5-year average uses nominal dollars to calculate the 2023 forecast for salaries, which does not account for labor escalation. Even if a 5-year average forecast methodology was used, which PG&E does not agree would be appropriate, the amount should be calculated using the average of base year dollars and then

³⁰⁷⁵ PG&E-08, p. 2-6, line 15 to p. 2-7, line 7. Additional information about HR Solutions and Service activities can be found throughout PG&E-08, Chapter (Ch.) 2.

³⁰⁷⁶ PG&E-21, p. 2-4, Table 2-1, line 5.

³⁰⁷⁷ PG&E-08, p. 2-1, lines 13-16; p. 2-14, lines 14-27.

³⁰⁷⁸ CALPA-11, p. 8, line 1 and p. 8, line 19.

³⁰⁷⁹ CALPA-11, p. 12, lines 18-20.

³⁰⁸⁰ CALPA-11, p. 7, line 19 to p. 13, line 1.

³⁰⁸¹ CALPA-11, p. 8, lines 17-18.

³⁰⁸² PG&E-08, p. 2-14, line 20.

escalated to 2023. That would result in a salaries forecast of \$21.7 million which is higher than the \$18.5 million recommended by Cal Advocates.³⁰⁸³

With respect to outside services, PG&E forecasts a net decrease of approximately \$180 thousand (approximately 7%) for 2023 as compared to 2020 recorded costs.³⁰⁸⁴ PG&E described that the 2023 forecast accounts both for increase for outside services is related to increased support for HR Operations and a decrease due to technology support compared to 2020.³⁰⁸⁵ These facts are also undisputed. Further, Cal Advocates' recommendation does not account for cost escalation. Even if a 5-year average forecast methodology were to be used, which PG&E does not agree would be appropriate, the amount should have been calculated using the average of base year dollars and then escalated to 2023.³⁰⁸⁶ This results in outside services forecast of \$2.0 million which is higher than the \$1.9 million recommended by Cal Advocates.³⁰⁸⁷ The Commission should not adopt Cal Advocates' recommendations. Cal Advocates has not demonstrated that PG&E's forecast methodology is unreasonable or incorrect. Further, correctly applied, Cal Advocates' recommendations would actually result in increases to PG&E's forecast as described above.

8.1.2 Information Technology

Each year minor enhancements to systems that support HR are required to support process changes or new requirements.³⁰⁸⁸ These updates will allow PG&E to make small changes to its systems to reflect program or process changes, address changes in technology

³⁰⁸³ CALPA-11, p. 8, line 1.

³⁰⁸⁴ PG&E-21, p. 2-9, Table 2-3, line 3.

³⁰⁸⁵ PG&E-08, WP 2-4, lines 30 and 42.

³⁰⁸⁶ The 5-year average would be calculated using PG&E-08, WP 2-2, average of line 4, multiplied by the 2023 escalation factor of 1.0570 found on line 10 of the same workpaper.

³⁰⁸⁷ CALPA-11, p. 8, line 19.

³⁰⁸⁸ PG&E-08, p. 2-15, lines 5-18, WP 2-10, for the Minor Enhancements Project Summary which provides additional details about this project.

required due to upgrades, or change interfaces to meet the requirements of external service providers. PG&E's TY 2023 expense forecast for information technology is \$0.3 million³⁰⁸⁹ and is uncontested. See Appendix A.

PG&E capital expenditures forecast for information technology as reflected in PG&E's rebuttal testimony is \$0.6 million in 2021, \$0 million in 2022, and \$0 in 2023.³⁰⁹⁰ PG&E's capital forecast is uncontested. See Appendix A.

8.2 HR Service Delivery and Inclusion

The HR Service Delivery and Inclusion Department includes the Talent Acquisition and Internal Mobility (Talent), Leadership and Employment Development, Performance and Inclusion, and Compensation functions. It also includes PG&E's forecast for its Workforce Transition Program. In addition, Chapter 3A – Report on Diversity, Equity and Inclusion (DEI), provides information on the diversity of PG&E's workforce and a summary of activities PG&E has undertaken to continue toward its goal of having a workforce that reflects the communities we serve.³⁰⁹¹ No parties took issue with the DEI Report.

8.2.1 Department Costs

The HR Service Delivery and Inclusion Department is led by the Vice President (VP) of Talent and Chief Diversity Officer and composed of the following six functions: (1) Talent; (2) Workforce Development; (3) Diversity, Equity and Inclusion; (4) Leadership and Employee Development (LED) Training; (5) Compensation; and (6) HR Investigations.³⁰⁹² PG&E's TY 2023 department cost forecast as reflected in rebuttal testimony is \$21.3 million.³⁰⁹³ The 2023

³⁰⁸⁹ PG&E-21, p. 2-5, Table 2-2, line 5.

³⁰⁹⁰ PG&E-21, p. 2-10, Table 2-5, line 3.

³⁰⁹¹ PG&E-08, p. 3-1, lines 7-15.

³⁰⁹² PG&E-08, p. 3-3, lines 2-10. Additional information about the department's activities can be found throughout PG&E-08, Ch. 3.

³⁰⁹³ PG&E-21, p. 3-4, Table 3-1, line 5.

forecast for HR Service Delivery and Inclusion Department is \$2.5 million (approximately 13%) higher than the 2020 recorded costs. This increase is primarily driven by labor escalation, addition of two full-time equivalent (FTE) employees supporting HR Investigations and Workforce Development departments, and an increase in contracts and materials primarily to support Workforce Development and Diversity, Equity and Inclusion efforts.³⁰⁹⁴

Cal Advocates recommends a \$2.3 million reduction to the HR Service Delivery and Inclusion Department costs, which includes a reduction of \$1.12 million for salaries and a reduction of \$1.18 million for outside services.³⁰⁹⁵ Cal Advocates contends that PG&E has not supported or adequately justified the increase in its forecast relative to the historical data and states that there is variability of the historical data.³⁰⁹⁶ Cal Advocates recommends the use of a 5-year average for salaries³⁰⁹⁷ and a 4-year average for outside services.³⁰⁹⁸

With respect to salaries, PG&E described the basis for the forecast increase compared to 2020 recorded costs as being attributable to standard labor escalation and the addition of two FTEs.³⁰⁹⁹ The additional FTEs will support: (1) HR Investigations - as a HR Investigator assisting with and conducting investigations into allegations of misconduct. PG&E hired one of these FTEs in 2021; and (2) Workforce Management - as a Power Pathways Program Manager, Expert to provide program outreach and develop programming.³¹⁰⁰ In its workpapers, PG&E provided detailed information about the need for the employees, the functions they would perform, job postings or profiles and alternatives considered to hiring for these positions

³⁰⁹⁴ PG&E-08, p. 3-1, lines 19-26.

³⁰⁹⁵ CALPA-11, p. 11, lines 10-11 and Table 11-7.

³⁰⁹⁶ CALPA-11, p. 12, lines 18-20.

³⁰⁹⁷ CALPA-11, p. 12, line 21 to p. 13, line 1.

³⁰⁹⁸ CALPA-11, p. 13, lines 18-19.

³⁰⁹⁹ PG&E-08, p. 3-8, line 28 to p. 3-9, lines 2-9 and WP 3-61 to WP 3-68.

³¹⁰⁰ PG&E-08, p. 3-9, lines 1-9.

including the continued use of contractors. ³¹⁰¹ This evidence is undisputed; Cal Advocates simply proposes using a 5-year average instead. Further, Cal Advocates' recommendation fails to account for labor escalation. Even if a 5-year average were used, which PG&E does not agree would be appropriate, the amount forecast should be calculated using the average of base year dollars and then escalated to 2023.³¹⁰² This would result in a salaries forecast of \$15.1 million, which is higher than the \$13.3 million recommended by Cal Advocates.³¹⁰³

With respect to outside services, the forecast increase for outside services is related to increased support for Workforce Development and Diversity, Equity and Inclusion efforts compared to 2020.³¹⁰⁴ Cal Advocates has not disputed that evidence, but proposes using a 4-year average instead.³¹⁰⁵ That methodology is inappropriate as it does not account for escalation and the increase business needs described in testimony and would result in a 2023 forecast that is actually lower than 2020 recorded costs. Even if a 4-year average were to be used, which PG&E does not agree would be appropriate, the amount should have been calculated using the average of base year dollars and then escalated to 2023.³¹⁰⁶ That would result in an outside services forecast of \$8.1 million which is higher than the \$4.3 million recommended by Cal Advocates. In addition, Cal Advocates recommendation of using 2017-2020 average excludes one year in which outside services spend was higher than the others, thereby skewing the average lower than can be fairly representative of the historical trend.

³¹⁰¹ PG&E-08, WP 3-61 to WP 3-68.

³¹⁰² The 5-year average would be calculated using PG&E-08, WP 3-2, average of line 1, multiplied by the 2023 escalation factor of 1.0993 found on line 16 of the same workpaper.

³¹⁰³ CALPA-11, p. 13, line 2.

³¹⁰⁴ PG&E-08, p. 3-9, lines 12-13.

³¹⁰⁵ CALPA-11, p. 13, lines 12-20.

³¹⁰⁶ The 4-year average would be calculated using PG&E-08, WP 3-2, average of line 3, multiplied by the 2023 escalation factor of 1.0570 found on line 15 of the same workpaper.

The Commission should not adopt Cal Advocates' recommendations. Cal Advocates has not demonstrated that PG&E's forecast methodology is unreasonable or incorrect. Rather, it has inconsistently proposed the use of averages of different time periods (4-year average / 5-year average) to support proposed reductions to PG&E's forecast. Further, correctly applied, both of Cal Advocates' recommendations would actually result in increases to PG&E's forecast as described above.

8.2.2 Companywide Expenses (Workforce Transition; Tuition Refund)

8.2.2.1 Workforce Transition

Over time, a company may experience changes in their workforce makeup whether it is through changes in technology, reduction in projects and customer needs, outsourcing of a function, an organizational update, or overall process changes. These changes may in turn impact employees through removal or redefinition of their position at the company. PG&E's Workforce Transition Program provides financial and career resource support to impacted employees and is designed to provide them time to transition into new positions at PG&E or pursue employment opportunities elsewhere.³¹⁰⁷

Severance payments are a common aspect of such a program. At PG&E, payments are based on an employee's length of service and their salary at the time of the position elimination. The cost of the severance payments is the most significant cost component of the overall program. PG&E encourages employees to look for open positions within the Company. To that end, employees receive full pay and benefits during a redeployment period (generally 45 days) where their sole responsibility is to look for a new position. In addition, the program offers support to employees through outplacement services.³¹⁰⁸

³¹⁰⁷ PG&E-08, p. 3-9, line 24 to p. 3-10, line 5.

³¹⁰⁸ PG&E-08, p. 3-10, lines 6-14.

PG&E's TY2023 expense forecast for companywide expenses is \$18.546 million.³¹⁰⁹ The 2023 forecast for the Workforce Transition Program \$14.7 million, which is approximately \$7 million higher than the 2020 recorded cost of \$6.7 million.³¹¹⁰ For Workforce Transition – Severance, Cal Advocates recommends \$6.56 million (a reduction of \$7.70 million or approximately 54%) compared to PG&E's 2023 forecast;³¹¹¹ for Workforce Transition – Outplacement Assistance, Cal Advocates recommends \$78 thousand (a reduction of \$308 thousand or approximately 75%).³¹¹² The Commission should not adopt Cal Advocates recommendations for the following reasons.

PG&E used a 5-year forecast as its forecast for 2023, which is the same methodology adopted by the Commission in the 2014 GRC³¹¹³ and which PG&E used in its last two GRC filings. Cal Advocates proposes the use of a 3-year average (2018-2020) instead. PG&E has described the cost fluctuations associated with this program in its testimony.³¹¹⁴ Cal Advocates has not refuted that. While Cal Advocates acknowledges that there has been significant fluctuation of program costs over the years, it nevertheless proposes changing the forecast methodology “to reflect the more current, lower expense trend”³¹¹⁵ and exclude the years with

³¹⁰⁹ PG&E-21, p. 3-5, Table 3-2, line 4. PG&E's expense forecast for department costs as reflected in the JCE is \$18.801M (PG&E-64, p. 3-19, Table 3C-1, lines 40-41).

³¹¹⁰ PG&E-21, p. 3-5, Table 3-2 (lines 1 and 2 combined represent the cost of the Workforce Transition Program).

³¹¹¹ CALPA-11, p. 14, lines 15-16.

³¹¹² CALPA-11, p. 15, lines 5-6.

³¹¹³ D.14-08-032, pp. 538-539.

³¹¹⁴ PG&E-08, p. 3-9, lines 11-13, and lines 17-22.

³¹¹⁵ CALPA-11, p. 15, lines 4-5.

higher program costs from the average.³¹¹⁶

The most recent three years of data do not represent “a more current, lower expense trend” as Cal Advocates states. They simply reflect years in which lower costs were incurred. While Workforce Transition costs in 2017 were higher than other years represented in the 5-year period of 2016-2020, that does not mean they were an anomaly and that will never reoccur. For example, in 2012, PG&E paid approximately \$32 million in severance costs. The purpose of using an average of historical costs as the forecast basis is to account for potential volatility in program costs. Such cost volatility is representative of workforce transition costs, which can fluctuate significantly based on changes in the organization and Company needs. It is inappropriate to exclude a particular year’s data simply because it is higher than other years. The Commission acknowledged this very issue in adopting PG&E’s forecast and rejecting a similar proposal from Cal Advocates (Division of Ratepayer Advocates or DRA at the time) in PG&E’s 2014 GRC as follows:

We adopt PG&E’s forecast of \$13.3 million for its Workforce Management Program costs in 2014. DRA acknowledges that program costs fluctuated over the 2007-2011 period, but claims 2009 was an anomaly that should be excluded from the average that makes up the forecast. We recognize that program costs fluctuate for a variety of reasons including process changes or new technology. Between 2007 and 2009, PG&E eliminated over 100 positions each year, followed by lower workforce reductions in 2010, and more than 250 in 2012. The five-year forecast eliminates volatility from year to year. Eliminating the higher years as DRA proposes, penalizes PG&E for taking steps needs to reduce workforce as requirements change.³¹¹⁷

PG&E’s Workforce Transition forecast is reasonable and necessary and should be approved.

³¹¹⁶ See, e.g., D. 20-07-038, p. 8 (finding that a party challenging a utility’s forecast had an affirmative duty to establish why the utility’s proposed methodology was unreasonable. That burden is not met where the challenging party “merely isolated the data that it liked and asked that we focus solely on that period of time. That does not prove it was unreasonable or unlawful for us to prefer to set costs using a broader period of time that offered more information”).

³¹¹⁷ D.14-08-032, pp. 538-539.

8.2.2.2 Tuition Refund

The Tuition Refund Program encourages employees to further their education through career- or job-related courses outside of PG&E. PG&E reimburses up to \$8,000 a year on tuition from a program-approved accredited school. While tuition costs have continued to rise, PG&E is not forecasting a change to amount of money available to individual employees. Since 2011, PG&E has used a third-party vendor to administer the Tuition Refund Program.³¹¹⁸

The Tuition Refund Program forecast for 2023 is \$3.9 million, \$1.8 million higher than 2020 recorded adjusted costs of \$ 2.1 million. ³¹¹⁹ Cal Advocates recommends \$3 million (a reduction of approximately \$0.9 million).³¹²⁰ The Commission should not adopt Cal Advocates' recommendation for the following reasons.

Cal Advocates recommendation is to use the 5-year average of historical costs as the forecast.³¹²¹ In doing so, Cal Advocates ignored the primary forecast driver, which is a forecast increase in participants compared to 2020. PG&E's forecast is based on a 5-year average of average cost per participant multiplied by the expected participation rate for 2023. PG&E's forecast accounts for an increased level of employee participation in the program in future years since PG&E's emergence from bankruptcy.³¹²² Because Diablo Canyon Power Plant (DCPP) was scheduled to retire, PG&E forecasted that an increased number of DCPP employees will participate in the Tuition Refund Program. These employees will receive an increase tuition allowance (above the base annual allowance) that is funded through the Joint Proposal—DCPP Employee Retention and Retraining Programs and not included in this request. Finally, the Tuition Program forecast also accounts for the forecast increase in total Company headcount by

³¹¹⁸ PG&E-08, p. 3-10, lines 15-23.

³¹¹⁹ PG&E-21, p. 3-5, Table 3-2, line 3.

³¹²⁰ CALPA-11, p. 15, lines 12-14.

³¹²¹ CALPA-11, p. 15, lines 8-14.

³¹²² PG&E-08, p. 3-10, line 25-28.

2023.³¹²³ Cal Advocates has not addressed this evidence in its testimony nor justified its exclusion from the forecast methodology.

8.3 Compensation: Short Term Incentive Plan (STIP), Non-Qualified Retirement, Rewards and Recognition and Labor Escalation

PG&E's TY2023 expense forecast for companywide expenses is \$235.885 million.³¹²⁴

The companywide expense programs and party recommendations are shown in Table 8-3, below.

**TABLE 8-3:
2023 COMPANYWIDE EXPENSE FORECAST – PG&E AND PARTIES RECCOMENDATIONS
(THOUSANDS OF NOMINAL DOLLARS)**

		PG&E's Forecast	Cal Advocates ^(a)	TURN ^(b)
1	<u>Non-Officer STIP</u>			
2	Utility STIP	\$224,702	\$(140,436)	\$(140,452)
3	Affiliated Entities	110	(70)	(69)
4	Total Non-Officer STIP	\$224,812	\$(140,506)	\$(140,521)
5	<u>Officer STIP</u>			
6	Utility	\$7,196	\$(4,497)	\$(4,498)
7	Affiliated Entities	553	(347)	(346)
8	Total Officer STIP	\$7,750	\$(4,448)	\$(4,844)
9	Total STIP Non-Officer and Officer	\$232,562	\$(145,350)	\$(145,364)
10	<u>Non-Qualified Retirement</u>			
11	Utility SERP	\$829	\$(415)	–
12	PG&E Corporation SERP	2,118	(1,059)	–
13	Total SERP	\$2,947	\$(1,474)	–
14	Supplemental Retirement Savings Plan (SRSP and DC-ESRP)			
15	Utility SRSP/DC-ESRP	\$357	\$(357)	–
16	PG&E Corporation SRSP/DC-ESRP	19	(19)	–
17	Total SRSP and DC-ESRP	\$376	\$(376)	–
18	Total Non-Qualified Retirement	\$3,323	\$(1,850)	–
19	Total Compensation Companywide Exp	\$235,885	\$(147,200)	\$(145,364)

(a) PG&E 2023 forecast for STIP shown in CA-11, Table 11-10 differs slightly from (PG&E-8) (Feb.28,2022), p. 4-26, Table 4-4. Cal Advocates did not recommend adjustment by Utility and Affiliated Entities. PG&E allocated the cost across the Utility and Affiliated entities proportionally for each plan.

(b) TURN reduction for STIP was based on the filed forecast amounts and does not take into account PG&E's Adjusted forecast.

TURN made no recommendation for PG&E Non-Qualified Retirement plan.

³¹²³ PG&E-08, p. 3-10, line 28 to p. 3-11, line 5.

³¹²⁴ PG&E-21, p. 4-3, Table 4-1, line 19. PG&E's expense forecast for companywide expenses as reflected in the JCE is \$236.757M (PG&E-64, Table 3C-1, lines 42-47).

8.3.1 Short Term Incentive Plan – Utility/Affiliates

PG&E's annual variable incentive pay plan, STIP, is an important component of compensation for most salaried employees. It is a normal part of a competitive compensation program.³¹²⁵ Additionally, it is an important mechanism for attracting, motivating, rewarding, and retaining a qualified, professional workforce.³¹²⁶ A variable pay compensation component is consistent with market practice for professional and managerial employees and provides significant benefits to both the Company and its customers.³¹²⁷ Among those benefits, a variable pay program aligns employee motivations with important Company objectives, such as customer welfare, prioritizing public and employee safety, and maintaining a financially healthy and viable Company.³¹²⁸

STIP metrics are almost entirely outcome-based, as opposed to activity- or effort-based.³¹²⁹ The STIP metrics are informed by the risk drivers associated with PG&E's top risks as identified through PG&E's Enterprise and Operational Risk Management program, which in turn is informed by the CPUC's Safety Model Assessment Proceeding and PG&E's Risk Assessment Mitigation Phase processing.³¹³⁰

The STIP has two measures: (1) Customer Welfare (75%); and (2) Financial (25%).

Customer Welfare: This measure is comprised entirely of safety and operational metrics. We continue to focus on customer welfare, prioritizing public and employee safety, which

³¹²⁵ PG&E-08, WP 7-72, (85 percent of energy companies and for-profit general industry companies offer STIPs to their employees).

³¹²⁶ PG&E-08, p. 4-10, lines 14-16.

³¹²⁷ PG&E-08, p. 4-10, lines 16-19.

³¹²⁸ PG&E-08, p. 4-10, lines 20-23.

³¹²⁹ Additional information on the STIP performance evaluation criteria is provided in WPs supporting this chapter. See PG&E-08, WP 4-10.

³¹³⁰ PG&E-08, p. 4-12, lines 9-15.

together account for 75% of its STIP performance measures.³¹³¹ This measure includes the largest-weighted safety metric in the Company's history. It also includes reliability, which emphasizes to supervisors that they must consider how the dependability of PG&E's service impacts its customers when establishing priorities and leading their teams.³¹³² The Customer Welfare metrics are shown in Figure 8-1 below.

**FIGURE 8-1
CUSTOMER WELFARE METRICS
(SAFETY AND OPERATIONAL: 75 % PROGRAM WEIGHTING)**

Electric Operations	• Wildfire Risk Reduction • Wire-Down Events Due to Equipment Failure Rate
Gas Operations	• Large Overpressure Events Rate • Total Dig-Ins Reduction
Generation	• Safe Dam Operating Capacity • DCPD Reliability and Safety Indicator
Reliability	• Gas Operations Customer Response • 911 Emergency Response • Customers Experiencing Multiple Interruptions – Unplanned • Average Speed of Answer (ASA) for Emergencies
Workforce Safety	• Days Away, Restricted, and Transferred Rate (DART) • Serious Injuries Actuals (excluding fatalities) • Percent of Serious Injury or Fatality (SIF) Investigations Completed in 30 days • Percent of SIF Corrective Actions Completed Timely

Financial: The remaining 25% corresponds to financial stability reflected in the Non-Generally-Accepted Accounting Principles Core Earnings Per Share (EPS) metric.³¹³³ The metric measures our success in optimizing revenue and controlling costs. Additionally, EPS is commonly used by the investment community, which represents a significant and necessary source of capital for PG&E's infrastructure investments.³¹³⁴

³¹³¹ PG&E-08, p. 4-12, lines 2-4.

³¹³² PG&E-08, p. 4-12, line 20 to p. 4-12, line 4.

³¹³³ PG&E-08, p. 4-12, lines 4-6.

³¹³⁴ PG&E-08, p. 4-15, lines 3-7.

8.3.1.1 Summary Of The Forecast And Parties' Recommendations

PG&E requests that the Commission adopt its 2023 STIP forecast of \$231.9 million for the Company,³¹³⁵ and \$0.7 million for affiliates (PG&E Corporation and PG&E Corporation Support Services II).³¹³⁶ The forecast is based on its 2020 employee population³¹³⁷ with an incremental headcount adjustment. The headcount adjustment was applied to reflect forecasted headcount growth in 2023.³¹³⁸ The \$94.0 million increase compared to 2020 recorded adjusted costs is primarily attributable to labor escalation, change in headcount, and the below-target 2020 STIP payment. PG&E is not requesting recovery of STIP for Company or Affiliate Executive Officers covered under SEC Rule 240.3b-7.

Both TURN and Cal Advocates recommend that the Commission determine the ratemaking treatment of STIP by attempting to allocate benefits of individual metrics between shareholders and customers, which essentially requests the Commission to disallow portions of the forecast. Table 8-4 is a summary of their funding recommendations, as well as an illustrative application of the Commission's incentive compensation ratemaking methodology adopted in its recent decisions on the Sempra utilities' 2019 GRC and the SCE 2021 GRC to PG&E's program design.

³¹³⁵ PG&E-08, WP 4-2, line 1 plus line 2.

³¹³⁶ PG&E-08, WP 4-2, line 3 plus line 4.

³¹³⁷ PG&E's forecast excludes SEC 3b-7 Officers for both the Utility and PG&E Corporation, as discussed in Section H of this testimony. *See* PG&E 8, p. 4-11, lines 7-8.

³¹³⁸ PG&E-08, WP 2-18, line 2 for forecasted increase in Management employees (STIP eligible employees).

**TABLE 8-4:
PG&E, CAL ADVOCATES, AND TURN'S RECOMMENDED FUNDING FOR STIP**

Line No.	Party / Decision	Customer Welfare (Safety and Operational) Weighting	Financial – EPS for PG&E Weighting	Total Proposed Ratepayer Funding for STIP at Target
Parties' Proposal				
1	PG&E	75%	25%	100%
2	Cal Advocates	37.5% ³¹³⁹	0% ³¹⁴⁰	37.5%
3	TURN	37.5% ³¹⁴¹	0% ³¹⁴²	37.5%
Recent Commission Decisions on STIP Applied to PG&E's Plan Design				
4	Sempra 2019 GRC Decision ³¹⁴³	75% - rejected cost sharing for safety and operational metrics ³¹⁴⁴	0-25% depending on evidentiary showing ³¹⁴⁵	75-100%
5	SCE 2021 GRC Decision ³¹⁴⁶	75% - rejected cost sharing for safety and operational metrics ³¹⁴⁷	0-25% depending on evidentiary showing ³¹⁴⁸	75-100%

8.3.1.2 The Commission Should Reject Cal Advocates' And TURN's Recommendations To Reduce STIP Funding

The Commission should reject TURN and Cal Advocates' proposed reductions to STIP for three reasons: (1) STIP is a significant portion of PG&E's employee compensation and is a reasonable cost of service; (2) PG&E's Customer Welfare Metrics, which comprise 75% of its STIP metrics, benefit customers; and (3) PG&E's sole financial metric, which comprises 25% of its STIP forecast benefits customers because a financially healthy utility is critical to customers'

³¹³⁹ CALPA-11, p. 28, Table 11-11.

³¹⁴⁰ CALPA-11, p. 18, line 21 to p. 19, line 6.

³¹⁴¹ TURN-16, p. 1, lines 5-11.

³¹⁴² TURN-16, p. 1, lines 4-11.

³¹⁴³ D.19-09-051.

³¹⁴⁴ D.19-09-051, p. 542, p. 752, Finding of Fact (FOF) 234.

³¹⁴⁵ D.19-09-051, p. 543, p. 752, FOF 235, p. 771, COL 83.

³¹⁴⁶ D.21-08-036.

³¹⁴⁷ D.21-08-036, p. 433, p. 620, FOF 530.

³¹⁴⁸ D.21-08-036, p. 431-432, p. 621, FOF 536.

interests. For each of these reasons, which are addressed in more detail below, PG&E's STIP is a reasonable cost of service and the Commission should adopt PG&E's forecast as presented and deny Cal Advocates and TURN's recommendations.

8.3.1.2.1 STIP Is A Reasonable Cost Of Service

STIP is a reasonable cost of service that should be fully funded. The Total Compensation Study (TCS) found that PG&E's target total compensation was competitive with the relevant market.³¹⁴⁹ That finding included the STIP paid at target, which is consistent with PG&E STIP forecast, which also assumes payments for performance at target.³¹⁵⁰ An at-risk incentive pay component like STIP is a prevalent, commonly-accepted compensation practice that is a valued component of a competitive compensation package for professional employees.³¹⁵¹ As such, it is an important part of PG&E's ability to attract and retain a skilled and qualified workforce. No party disputes this fundamental point.

While the Commission indicated in 2004 that utilities have discretion to offer employees the portion of compensation covered in the STIP as base pay if they so choose, doing so would be less valuable for customers as the employees would receive the compensation regardless of how the Company performed against its key goals. Converting STIP to base pay would be inconsistent with a purpose of Assembly Bill 1054 which requires, as a condition of obtaining an annual safety certification, that an electrical corporation's compensation plan impose:

...strict *limits* on guaranteed cash compensation [for executive officers], with the primary portion of the executive officers' compensation based on achievement of objective performance metrics.³¹⁵²

³¹⁴⁹ PG&E-08, p. 4-5, lines 4-5.

³¹⁵⁰ PG&E-08, p. 4-11, lines 11-12.

³¹⁵¹ PG&E-08, p. 4-15, lines 12-17.

³¹⁵² Pub. Util. Code § 8389(e)(6)(A)(i)(I) (emphasis added).

Although the statute does not impose this requirement with respect to employees who are not executive officers, it reflects a legislative judgment about the importance of at-risk incentive compensation programs at California's electrical utilities.³¹⁵³

The Commission has acknowledged that the mix of base pay and incentive pay should be within the Company's managerial discretion.³¹⁵⁴ There are three principal reasons why STIP is a reasonable cost of service: (1) at-risk compensation programs like STIP are an important part of PG&E's ability to attract and retain professional employees; (2) providing this compensation to employees as at risk pay rather than base pay aligns management and employee focus on important company priorities including safety and reliability; and (3) PG&E's total compensation, including its STIP forecast, is competitive with the market. Parties have not refuted these points.

No party has disputed PG&E's evidence that programs like STIP are an important part of the Company's ability to attract and retain professional employees, which is of critical importance to the Company. PG&E addressed this issue in its opening testimony, where it stated:

An incentive program like STIP is a typical component of a company's compensation package and is a valued component of the total pay package for professional and management employees. The Commission has acknowledged that short-term incentive compensation is a valuable tool for attracting and retaining skilled professionals.³¹⁵⁵

...

Every PG&E Supervisor, Manager, Director, and Executive participates in STIP. These employees establish Company policy, set direction and goals, provide the day-to-day supervision for all employees, and are ultimately responsible for ensuring the Company's success in achieving key business objectives. In addition, PG&E non-supervisory employees, including those salaried employees represented by the ESC and IBEW, participate in STIP. Conditioning a

³¹⁵³ PG&E-21, p. 4-5, lines 19-22.

³¹⁵⁴ D.04-07-022, p. 208.

³¹⁵⁵ PG&E-08, p. 4-15, lines 12-17; D.13-05-010, p. 875.

component of management and professional employees' compensation on the achievement of specific Company goals is a widely-accepted compensation practice and important part of their compensation package.³¹⁵⁶

Additionally, in its decision approving PG&E's Plan of Reorganization, the Commission found that PG&E's executive compensation plan, "will promote public accountability, independent review, and incentives that further the purposes of AB 1054..."³¹⁵⁷ The specific safety-related metrics included in PG&E's STIP are reviewed by State regulators in connection with annually approving PG&E's executive compensation structure, and the Commission and the Office of Energy Infrastructure Safety approved PG&E's structures in 2020 and 2021, respectively.³¹⁵⁸ PG&E also provided survey evidence of the prevalence of these programs in the industry. Specifically, Willis Towers Watson (WTW) found that 85% of energy companies offer short-term incentive programs to their employees.³¹⁵⁹ WTW also noted that for the energy sector, safety, operating income and cash flow were the most prevalent metrics.³¹⁶⁰ Parties did not address or refute the evidence PG&E provided about the prevalence of these programs in the market or their importance to PG&E's ability to attract and retain professional and management employees to its workforce.

Conditioning a portion of employees' pay on achievement of important company objectives benefits customers. As PG&E discussed in testimony:

STIP has the advantage of aligning work priorities, which Managers and other leaders set for their teams, directly with important Company objectives and customer interests, such as customer and workforce welfare and the Company's financial health. STIP gives management the flexibility to respond to changing

³¹⁵⁶ PG&E-08, p. 4-15, lines 19-30.

³¹⁵⁷ D.20-05-053, pp. 91 and 93.

³¹⁵⁸ D.20-05-053 p. 91, and p. 109, COL 2 (approving PG&E's 2020 executive compensation structure, including the 2020 STIP program design); Office of Energy Infrastructure Safety letter to PG&E (Oct. 19, 2021) (approving PG&E's 2021 structure, including the 2021 STIP program design). PG&E's request for approval of its 2022 executive compensation structure remains pending with the Office of Energy Infrastructure Safety.

³¹⁵⁹ PG&E-08, p. 4-15, lines 18-19; WP 7-72.

³¹⁶⁰ PG&E-08, WP 7-72.

business and customer needs, by paying for performance within the parameters of the plan each year. The makeup of PG&E's STIP Program has changed significantly over the years, and now includes the largest-weighted safety metric in the Company's history. In addition, the STIP metrics are almost entirely outcome-based as opposed to activity- or effort -based. Using compensation as a tool to align employees around specific goals would not be possible if PG&E provided all compensation in the form of fixed base pay.³¹⁶¹

Finally, STIP was included in the TCS, which found PG&E's total compensation to be competitive with the market.³¹⁶² No party has refuted this evidence.

8.3.1.2.2 The Commission Should Reject Cal Advocates' And TURN's Cost Sharing Recommendations For Customer Welfare Metrics

Cal Advocates and TURN each recommend that the Commission only fund half of the Safety and operational metrics, which comprise 75% of PG&E's STIP.³¹⁶³ If adopted, this recommendation alone would result in a 37.5% reduction to the total program forecast. The Commission should reject these recommendations because: (1) they are contrary to the Commission's most recent precedent on incentive compensation; and (2) they would produce illogical and unreasonable results.

The Commission explicitly rejected cost sharing of safety and operational metrics in Sempra's 2019 GRC. The Commission's guidance was clear and sensible. In that case, Cal Advocates (then ORA), recommended a 50% reduction for safety and operational metrics.³¹⁶⁴ The Commission denied ORA's proposal, finding that it should approve full funding in rates for metrics that "promote either safety, operational efficiency, reduced costs, improved service" *even where shareholders may also get some benefit from those activities.*³¹⁶⁵ The Commission explained:

³¹⁶¹ PG&E-08, p. 4-16, lines 20-33.

³¹⁶² PG&E-08, p. 7-4.

³¹⁶³ CALPA-11, p. 28, Table 11-11; TURN-16, p. 1, lines 5-11.

³¹⁶⁴ D.19-09-051, p. 541.

³¹⁶⁵ D.19-09-051, p. 542.

We reviewed the various performance metrics for the ICP and find that most of the performance metrics provide tangible benefits to ratepayers in that they encourage and promote either safety, operational efficiency, reduced costs, improved service, or a policy that the Commission. *While some metrics also align with shareholder goals, we find that these are not necessarily inconsistent with ratepayer benefits.*³¹⁶⁶

The Commission followed the same approach in SCE’s 2021 GRC, rejecting cost sharing of operational metrics.³¹⁶⁷

The Commission’s decisions in the recent Sempra and SCE GRC’s are also consistent with the important state policy of supporting safety as expressed both by the California legislature and the Commission’s own safety culture consultant—NorthStar. For example, in AB 1054, the California legislature made clear that safety is a top priority for the state, saying:

The state has a substantial interest that its electrical corporations are operating in a safe and reliable manner and have access to capital at reasonable costs to make safety investments.³¹⁶⁸

In addition, the Commission’s NorthStar consultant encouraged PG&E to increase the weighting of its safety metrics related to incentive compensation.³¹⁶⁹ PG&E has done so and now has the biggest safety component of STIP in the program’s history. Given this clear policy guidance from the Commission and from the California Legislature, the Commission should not

³¹⁶⁶ D.19-09-051, p. 542 (emphasis added).

³¹⁶⁷ D.21-08-036, p. 433.

³¹⁶⁸ Assem. Bill No. 1054 (2019-2020 Reg. Sess.) § 2(c).

³¹⁶⁹ NorthStar Consulting Group, Assessment of Pacific Gas and Electric Corporation and Pacific Gas and Electric Company’s Safety Culture (The NorthStar Report) (May 8, 2017), p. VII-20, recommendations 3, 5, and 6, encouraging PG&E to increase the weighting of safety metrics in its LTIP, to revisit all STIP metrics in light of NorthStar’s recommended enterprise-wide safety plan, and to develop a more robust set of BRP metrics addressing various, broad areas of safety. The NorthStar Report was prepared as part of a public Commission proceeding and the Commission can take official notice of it pursuant to CPUC Rule of Practice and Procedure 13.10. An excerpt of the report was accepted into evidence as CALPA-19. The full report is available on the Commission’s website at: <<https://www.cpuc.ca.gov/-/media/cpuc-website/industries-and-topics/documents/pge/safety-culture/pge-final-safety-report-5-8-17-northstar-consulting.pdf>> (as of Oct. 26, 2022)

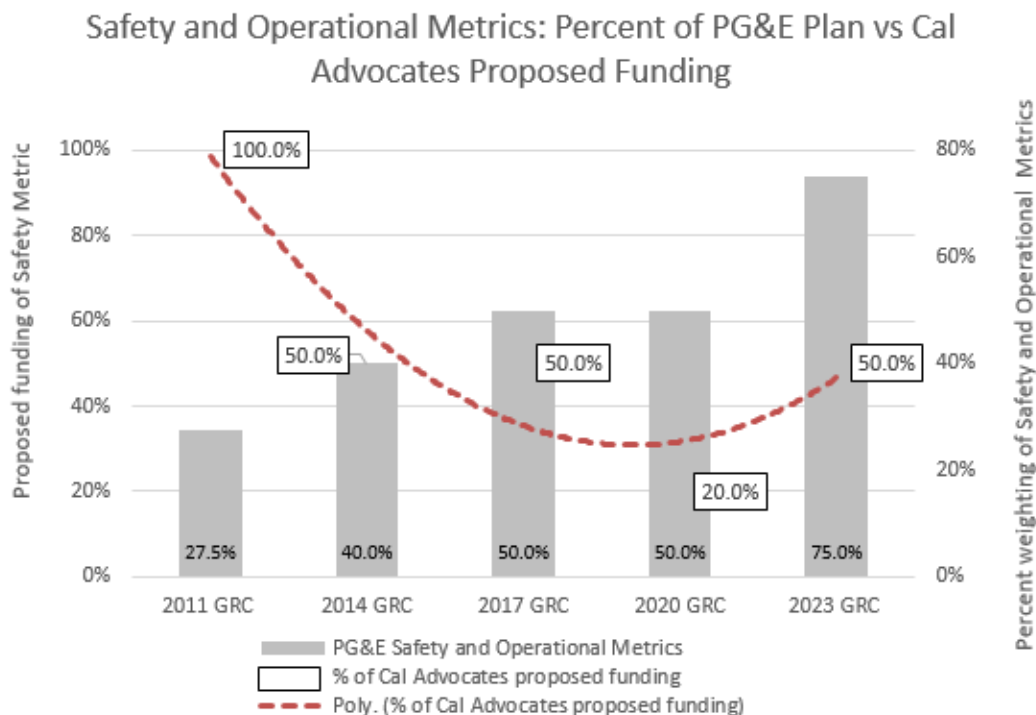
adopt parties' recommendations to reduce funding for compensation in rates because PG&E has increased its focus on safety and operational metrics.

Although both Cal Advocates and TURN have approached their recommendations similarly, a review of Cal Advocates' recommendations from prior GRCs illustrates how illogical results can be brought about by such an analysis. In the first instance, Cal Advocates' and TURN's recommendations regarding ratepayer funding should be given little if any weight for the reason that they are so clearly inconsistent with their positions in prior GRCs. As PG&E has increased its focus on safety (which Cal Advocates previously supported for full funding in STIP) and reduced the weight of financial performance in the STIP—Cal Advocates has changed the basis for its recommendations to support even greater reductions for STIP funding.

The chart below shows the increasing weighting of PG&E's safety and operational metrics over the years, compared to Cal Advocates' changing recommendations as to what percentage of those metrics should be funded in rates.³¹⁷⁰ As shown in Figure 8-2, as PG&E's safety and operational metrics have gone from 27.5% to 75% of the STIP, Cal Advocates has proposed to reduce funding for these metrics from 100% to 50%.

³¹⁷⁰ Please note, the 2011 information provided in Figure 4-1 was called Operational Excellence at that time, and also included reliability metrics that are not included in PG&E's current STIP Program.

FIGURE 8-2
PROPOSED FUNDING FOR SAFETY AND OPERATIONAL METRICS OVER TIME



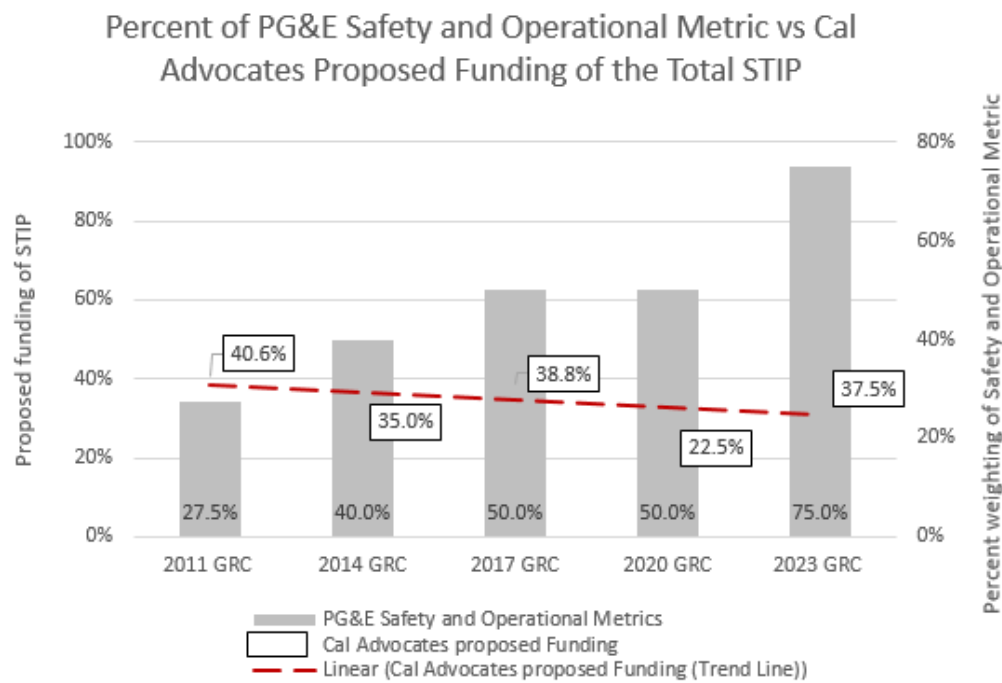
TURN has moved in the same direction. As PG&E has increased its focus on safety, TURN has moved away from its prior proposal of 100% funding of the safety and operational metrics in the 2014 GRC, to recommending 50% funding in the 2017, 2020, and 2023 GRCs.³¹⁷¹

Figure 8-3 shows the evolution of parties' total STIP funding recommendations compared to the weight of safety and operational metrics. Along with parties' usual

³¹⁷¹ TURN-16, p.11, lines 3-4 (2023 GRC). TURN-11, p. 9, lines 11-12; (A.18-12-009, 2020 GRC); Exhibit TURN-9, p.14, lines 14-15 (recommending “equal cost sharing of the cost of the remaining STIP measures between ratepayers and shareholders” aside from the Financial and Customer metrics, which TURN addressed separately) (A.15-09-001, 2017 GRC); D.14-08-032, p. 518 (noting that TURN recommends reductions based on the Financial and Customer Satisfaction metrics. TURN recommends no specific reductions to safety or reliability metrics) (2014 GRC).

recommendations not to fund the financial metric, the end result is an even bigger recommended total reduction for STIP Program funding now than in 2011, when PG&E’s financial metric was twice its current weight, and the safety and operational metrics were approximately one-third of their current level.³¹⁷²

**FIGURE 8-3
PROPOSED FUNDING FOR STIP PROGRAM OVER TIME**



The information provided in Figures 8-2 and 8-3 clearly illustrates the type of illogical and unreasonable result which Cal Advocates’ and TURN’s cost-sharing proposals can yield, and why the Commission should reject them.

³¹⁷² Application (A.) 09-12-020, Exhibit DRA-14, p. 6, Table 14-3 (recommending a total of 40.62 percent ratepayer funding for STIP).

8.3.1.2.3 The Commission Should Reject Cal Advocates' And TURN's Proposed Reductions Related To The Earning Per Share Metric

Both Cal Advocates and TURN recommend no funding for the portion of STIP associated with the EPS metric, which would result in a 25% reduction to PG&E's STIP forecast.³¹⁷³ The Commission should reject this recommendation as a financial metric is a commonly-accepted practice in compensation programs, the Company's financial health directly affects customers, and there is no inherent conflict of interest between shareholders and customers caused by including this metric in the STIP program.

The use of financial metrics is a commonly accepted compensation practice.³¹⁷⁴ As noted by WTW in the energy sector, safety is one of the most prevalent performance measures (64%), while operating income, including both adjusted and unadjusted measures (i.e. GAAP and non-GAAP) follows closely (46%).³¹⁷⁵ Moreover, given the fact of PG&E's recent bankruptcy, credit downgrades, and focus of legislation including AB 1054, it is difficult to comprehend parties' arguments that the Company's financial health is not of direct concern and importance to customers. Our financial performance can affect our ability to raise capital at a reasonable cost. It also affects our access to trade credit necessary to support its operations, particularly the procurement of natural gas and electricity under long- and short-term contracts.³¹⁷⁶ The Commission has acknowledged that financial performance can benefit customers.³¹⁷⁷ Beyond the Commission's own guidance, the California legislature spoke directly to this topic in AB 1054, explaining the direct effect the Company's financial health has to success in improving the safety of its system. The legislature stated:

³¹⁷³ CALPA-11, p. 18, line 21 to p. 19, line 6; TURN-16, p. 1, lines 4-11.

³¹⁷⁴ PG&E-08, p. 4-14, lines 9-13, referencing PG&E-08, WP 7-72.

³¹⁷⁵ PG&E-08, WP 7-72; TURN-904 (PG&E Response to TURN 258, Q.2 subparts b. d. and e.).

³¹⁷⁶ PG&E-08, p. 4-14, line 16 to 4-15, line 2; PG&E-14, p. 3-7, lines 11-14.

³¹⁷⁷ D.13-05-010, p. 882.

The state has a substantial interest that its electrical corporations are operating in a safe and reliable manner and have access to capital at a reasonable cost to make safety investments.³¹⁷⁸

Cal Advocates and TURN both criticize the use of the EPS specifically as the STIP financial metric and point to other types of financial metrics that could be used instead. While they may have identified alternatives that could have been used, neither have shown the EPS to be unreasonable to include in STIP. The EPS measures specific aspects of the company's performance and is commonly used by the investment community, which is a significant source of capital for PG&E's infrastructure investments.³¹⁷⁹ Cal Advocates takes issues with financial metrics generally, stating:

[I]ncentive criteria tied to...financial goals are clearly shareholder oriented... While there is no direct benefit to ratepayers, there is a tangible benefit to shareholders in the form of dividends and higher stock prices. There is a stronger correlation between the returns of a regulated entity and the performance of executives, as opposed to rank-and-file staff. As such, there is no justification to support ratepayer funding of this part of the incentive matrix.³¹⁸⁰

TURN criticizes various aspects of the EPS metric. Specifically, TURN comments that EPS does not measure shareholder returns or financial performance and diverges from the shareholder experience.³¹⁸¹ These parties' criticisms are off base. The EPS is not designed to measure total shareholder return as is reflected in stock price. Stock performance and other publicly available financial information in PG&E's Securities and Exchange Commission filings are indicators of that and are readily available to the investment community for that purpose. The purpose of EPS is to convey one particular aspect of the Company's financial health—financial management—which addresses the Company's success in optimizing revenue and controlling costs relating to normal business operations.³¹⁸² The EPS metric puts the focus on

³¹⁷⁸ AB 1054 (2019-2020 Reg. Sess.) § 2(c).

³¹⁷⁹ PG&E-08, p. 4-15, lines 3-7.

³¹⁸⁰ CALPA-11, p. 21, line 20 to p. 22, line 4.

³¹⁸¹ TURN-16, pp. 3-7.

³¹⁸² PG&E-08, p. 4-15, lines 3-4.

ensuring strong performance in the areas which the professional employees who are STIP-eligible can control—mainly, efficient financial management of their operating budgets. Investors care about the non-GAAP information precisely because it gives them a picture of how well PG&E is managing its budgets for core work.³¹⁸³

TURN also takes issue with the EPS being a non-GAAP measure and more specifically that it excludes Items Impacting Comparability (IIC) from EPS earnings.³¹⁸⁴ TURN alludes to the EPS removing costs associated with management or safety missteps throughout its testimony and states that IIC items “insulate[s] management from the financial impacts of safety missteps and delivers a strong message to STIP recipients regarding the companies’ priorities and management responsibilities.”³¹⁸⁵

First, the California legislature has made clear that there is not an inherent conflict of interest between safety performance and financial performance. As AB 1054 states, a Company’s access to capital at a reasonable cost affects its ability to make safety-related investments.³¹⁸⁶ Second, this argument is belied by the program design itself and also inconsistent with PG&E’s overall management compensation structure. Safety and operational metrics make up the largest portion of the STIP. At 75%, they are three times the weight of the EPS metric. Additionally, while the EPS is not designed to be a holistic measure of shareholder return, metrics in other areas of compensation such as the LTIP have historically filled that role—and in fact, the LTIP program design includes relative total shareholder return as a modifier or metric. As discussed in the NorthStar report, historically, the occurrence of safety-

³¹⁸³ PG&E-21, p. 4-19, lines 12-17; see also TURN-904, PG&E’s Response to TURN 258 Q2c (noting that PG&E non-GAAP financial data to investors as part of its quarterly earnings materials.)

³¹⁸⁴ TURN-16, pp. 3-5.

³¹⁸⁵ TURN-16, p. 7, line 27 to p. 8, line 2.

³¹⁸⁶ AB 1054 (2019-2020 Reg. Sess.) § 2(c).

related events had a significant effect on compensation for management employees and executives by virtue of those significant decreases in stock price.³¹⁸⁷

Finally, TURN notes that the Commission previously chose not to adopt funding for the Earnings From Operations STIP metric in use at that time and states that “there is no reason to reach a different outcome here.”³¹⁸⁸ Where the Commission has declined to adopt funding for financial metrics, it has often done so based on the failure of the applicant to demonstrate real benefits to ratepayers from the measure.³¹⁸⁹ In this case, PG&E has provided substantial evidence to demonstrate that a real and tangible ratepayer benefit exists related to its financial metric.³¹⁹⁰ For example, proposals that shareholders should bear the costs of reasonable costs of service including STIP may not be seen by credit agencies and by investors as evident of a regulatory environment that is supportive of the utility’s financial health.³¹⁹¹ This could lead investors to look elsewhere for their investments, or to require a higher return for bearing greater political risk. If implemented, PG&E’s credit metrics would worsen, possibly leading to a downgrade in PG&E’s credit ratings and increasing customer costs through a higher cost of

³¹⁸⁷ The San Bruno accident, 2017 Northern California wildfires, and 2018 Camp Fire were followed by sharp decreases in the Company’s stock price. Historically, this had a significant effect on compensation for many in management and executive roles. The NorthStar report included discussion of this with respect to the San Bruno accident in particular, noting that: (1) compared to percent payout in December 2010, in 2012, 2013 and 2014, there was no payout for performance shares as a result of PG&E’s total shareholder return being at the bottom of the comparator group; (2) in 2015 and 2016, the payout was 35 percent and 50 percent, respectively; and (3) the Restricted Stock Unit portion of the program was also well below the comparator group for this period. (NorthStar Report) p. VII-14.

³¹⁸⁸ TURN-16, p. 8, lines 11-12.

³¹⁸⁹ See, e.g., D.21-08-036 (SCE 2021 GRC), p. 620, FOF 530, (“SCE has failed to demonstrate that costs related to the Financial Performance STIP goal category (weighted at 30 percent of STIP goals) are reasonable.”)

³¹⁹⁰ See PG&E-21, p. 4-15, line 20 to p. 4-20, line 2; see also, PG&E-14, p. 3-11, line 17 to p.3-18, line 5 (describing the importance of the Company’s financial health to the Company and its customers generally.).

³¹⁹¹ PG&E-14, p. 3-11, lines 18-24.

capital.³¹⁹² As such, the Commission should consider this issue in light of the record in this case, not from others. PG&E has provided sufficient evidence that the general financial health of the company is of critical importance to customers and that the EPS metric provides investors with valuable information about one aspect of that financial health, which investors might not otherwise have access to.

For the reasons discussed above, STIP is a reasonable cost of service that should be funded in rates. The program conditions a portion of employee compensation upon performance on fundamental priorities that are important both to the Company and to customers. As such, the Commission should reject Cal Advocates' and TURN's recommendations and approve PG&E's STIP forecast.

8.3.2 Non-Qualified Retirement

There are two components to PG&E's defined benefit retirement (pension) benefits: (1) PG&E's tax-qualified Retirement Plan (pension); and (2) non-qualified pension benefits including the Supplemental Executive Retirement Plan (SERP), and the Supplemental Retirement Savings Plan (SRSP).³¹⁹³

PG&E's 2023 forecast for non-qualified pension plans for former employees and future benefits for current non-Officer and non-SEC 3b-7 Officer employees is \$3.6 million, a \$66 thousand increase over the equivalent recorded adjusted 2020 costs.³¹⁹⁴ Cal Advocates proposes a reduction of \$1.8 million (50%) to PG&E's combined forecast of Non-Qualified retirement plans. The stated basis for the proposed reduction is that ratepayers should not bear the full costs of these supplemental benefit programs. In addition, Cal Advocates indicates that it is not clear if PG&E adjusted its forecast consistent with Commission guidance.³¹⁹⁵

³¹⁹² PG&E-14, p. 3-11, line 27 to pp. 3-12, line 5.

³¹⁹³ PG&E-08, 4-18, lines 11-14.

³¹⁹⁴ PG&E-08, WP 4-17, line 10.

³¹⁹⁵ CALPA-11, p. 29, lines 10-17.

The Commission should not adopt Cal Advocates' recommendations for the following reasons. The SERP plan forecast has already been adjusted by 50% consistent with commission guidance.³¹⁹⁶ The adjustments made to 2020 recorded include removing the following costs: excess benefit plans, 2019 catch-up payments, payments made to SEC 3b-7 Officers, and, finally, an adjustment of 50% for cost recovery. Cal Advocates acknowledges that these adjustments were made and shown in the workpapers and describes each adjustment in its testimony.³¹⁹⁷ Table 8-5 below summarizes each adjustment, shows how the 2023 forecast was developed, and shows that the amount included in the forecast, \$2.947 million, is the result after being adjusted by 50% per Commission guidance.³¹⁹⁸

The non-qualified defined contribution plan is made up of the Supplemental Retirement Savings Plan (SRSP) and the Defined Contribution Executive Supplemental Retirement Plan (DC-ESRP). PG&E has already agreed reduce the forecast for those programs by 50%. This will result in a reduction of \$0.3 million to PG&E 2023 forecasts.³¹⁹⁹ No additional forecast reductions are warranted.

³¹⁹⁶ PG&E-21, p. 4-34, Table 4-3, line 8.

³¹⁹⁷ CALPA-11, p. 30, line 6–9.

³¹⁹⁸ D.14-08-032, p. 533. In PG&E's 2014 GRC decision (PG&E's last fully-litigated GRC) the Commission adopted 50 % of PG&E's forecast for the SERP portion of the Non-Qualified Retirement plans.

³¹⁹⁹ PG&E-21, p. 4-33, lines 4-14.

TABLE 8-5
SUPPLEMENTAL EXECUTIVE RETIREMENT PLAN (SERP)
(THOUSANDS OF DOLLARS)

Line No.	Description	Utility	PG&E Corp	Total
1	2020 Recorded	\$3,595	\$11,287	\$14,882
2	Adjustments			
3	Adjust: Excess Benefit Plan	\$(678)		\$(678)
4	Adjust: 2019 Catch payments, interest and other	\$(1,260)	\$(7,223)	\$(8,483)
5	Adjust: SEC 3b-7 Officers	–	\$(56)	\$(56)
6	Total Adjustments	\$(1,938)	\$(7,279)	\$(9,217)
7	Total Recorded Adjusted (ln 1 + ln 6)	\$1,657	\$4,008	\$5,665
8	Adjust 50% for Cost Recovery (50% * ln 7)	\$(829)	\$(2,004)	\$(2,832)
9	2020 Recorded, Adjusted for 50% Cost Recovery (ln 7 + ln 8)	\$829	\$2,004	\$2,832
10	Escalation (2020 to 2023)	1.00	1.057	–
11	2023 SERP Forecast (ln 9* ln 11)	\$829	\$2,118	\$2,947
Note Source: (PG&E) (Feb. 28, 2022) WP 4-18 and WP 4-17.				

8.3.3 Rewards And Recognition (R&R): The Commission Should Not Adopt Cal Advocates Recommendation For PG&E's R&R Program.

The Reward and Recognition (R&R) Program provides leaders with an opportunity to provide recognition to employees who have gone above and beyond their normal job responsibilities. The R&R Program is a very economical way in which PG&E can recognize and encourage employees to work safely, go above and beyond to achieve results, and encourage innovation.³²⁰⁰

In 2020 PG&E spent \$18.9 million on R&R.³²⁰¹ These costs are recorded typically in the cost center for the employee receiving the compensation and are not separately forecasted within this chapter. In 2023, the R&R Program expenditures are estimated to be \$18.6 million,

³²⁰⁰ PG&E-08, p. 4-21, lines 8–13.

³²⁰¹ PG&E-08, WP 4-29.

which is the average of the 2018-2020 recorded total for the R&R Program plus labor escalation.³²⁰² Cal Advocates recommends zero funding for the R&R Program.³²⁰³

The R&R program is reasonable and provides benefits to our customers. By using the R&R Program, a leader can highlight behaviors and specific accomplishments that have helped the department and Company achieve its goals. In addition, these types of awards are a low-cost way of showing hard-working employees that they are valued, appreciated, and that their extra contributions do not go unnoticed. In this way, the program promotes retention of high-performing employees, which is in the interest of both the Company and its customers. PG&E's R&R Program does not include celebratory lunches or other similar events.³²⁰⁴

Programs like PG&E's R&R Program are a commonly-accepted compensation practice.³²⁰⁵ Although not as prevalent as other incentive programs such as STIP and LTIP, they are considered effective at driving performance.³²⁰⁶

Further, the Commission has recognized the value of R&R. In PG&E's last fully-litigated GRC, the Commission approved PG&E's R&R program stating:

This program is similar to those offered by the other California utilities. We conclude that the program provides a reasonable way to reward employees who help improve the operations of the utility, or provide exceptional service, or otherwise distinguish themselves. The program helps promote retention of strong employees, which benefits both PG&E and its ratepayers.³²⁰⁷

In recommending no funding for the program, Cal Advocates states:

Due to PG&E's compensation being above market and PG&E's R&R Program request being forecast at a significantly higher amount than the other California

³²⁰² PG&E-08, WP 4-29.

³²⁰³ CALPA-11, p. 32, lines 8-9.

³²⁰⁴ PG&E-08, p. 4-21 lines 14-21.

³²⁰⁵ PG&E-08, WP 4-31, WorldatWork Trends in Employee Recognition, 87 percent of employers surveyed offered recognition programs.

³²⁰⁶ PG&E-08, p. 4-21, lines 23-25 referencing Aon plc, 2019 Variable Compensation MeasurementTM (VCMTM) Report – U.S. Edition, p. 96.

³²⁰⁷ D.14-08-032, p. 525.

utilities, Cal Advocates recommends that ratepayers not be burdened with funding PG&E's Recognition Programs.³²⁰⁸

This argument is misplaced. First, WTW found PG&E's 2020 target total compensation was competitive, not "above market" as Cal Advocates claims.³²⁰⁹ Second, PG&E's forecast for 2023 R&R, before escalation, is less than PG&E's 2020 recorded spend.³²¹⁰ Third, it is expected that the cost of PG&E's program would be higher than other IOUs because PG&E has significantly more employees.³²¹¹ Fourth, PG&E's program is consistent with applicable benchmarking. In a 2019 World at Work study on employee recognition, 68-80% of responding employers budgeted for recognition programs, with their programs comprising 0.1% to 10.1% of their payroll budgets.³²¹² PG&E's recognition program in 2020 was less than 1% of its total labor.³²¹³ Finally, PG&E's R&R Program not only supports and encourages excellence and innovation in employees' everyday work, but also recognizes employees' support for PG&E's Emergency Operations Center (EOC) beyond the responsibilities of their everyday roles. PG&E's EOC partners with state and local governments and agencies to respond to large-scale emergency incidents in communities within its service territory. PG&E employees who work in EOC support functions are typically overtime-exempt employees who are performing tasks outside of, and in addition to, their normal duties, and working extended shifts of up to 12 hours, days or nights, and on weekends and holidays. Over the past seven years, the number of EOC incidents has steadily increased, which has been reflected in the increasing amount spent on

³²⁰⁸ CALPA-11, p. 32, lines 5-8.

³²⁰⁹ See discussion Section 8.6.

³²¹⁰ PG&E-08, WP 4-28.

³²¹¹ PG&E-21, p. 4-35, lines 7-9.

³²¹² PG&E-21, p. 4-35, lines 9-13.

³²¹³ PG&E-21, p. 4-35, lines 13-14.

EOC-related R&R awards.³²¹⁴ For these reasons, the Commission should adopt PG&E's forecast for the R&R as presented in its testimony.

8.3.4 Labor Escalation

PG&E strives to offer compensation that is cost effective and competitive with industry peers and other local markets where the Company competes for talent. In support of this compensation strategy, for non-represented employees (also referred to as non-bargaining unit employees)—we monitor wage escalation in the market and increase our employees' base pay annually relative to the market. For represented employees (also referred to as bargaining unit employees)—wage increases are negotiated through the collective bargaining process.³²¹⁵ PG&E provided a summary of general wage increases and market-based wage increases for 2021 through 2026.³²¹⁶ No party made specific recommendations with respect to PG&E's Labor escalation (2021 to 2023). For PG&E's response to Cal Advocates' and TURN's recommendations for Post Test Year escalation, see the discussion in Section 11.

8.4 Employee Benefits

PG&E offers its employees a comprehensive and competitive package of health and wellness, retirement and insurance benefits programs. PG&E's integrated benefits programs are essential to keeping its workforce healthy, safe and productive. Health, retirement, and insurance benefits also help to attract and retain the diverse, skilled workforce necessary to provide safe and reliable electric and gas service to PG&E's customers.³²¹⁷

³²¹⁴ PG&E-21, p. 4-35, lines 24-26.

³²¹⁵ PG&E-08, p. 4-22, lines 10-17.

³²¹⁶ PG&E-08, 4-22, lines 17-18 and Table, 4-2.

³²¹⁷ PG&E-08, p. 5-1, lines 5-11.

Employee benefits are a significant component of the total compensation package.³²¹⁸ A competitive benefits program, including health and retirement plans in conjunction with other compensation, is necessary to attract and retain the highly skilled workforce that is required for PG&E's ongoing utility operations. In addition, benefits are a key component to attract and hire qualified individuals to complete the critical infrastructure work to provide continuity of service during critical times and for the safety of PG&E's customers and communities.³²¹⁹ The PG&E-sponsored benefits forecast reflects input from the marketplace, collective bargaining agreements and government regulations.

8.4.1 Department Costs

The Benefits Department oversees the administration of PG&E's various benefit plans, including Medical (active and retiree), Dental, Vision, Retirement, Relocation and the other plans described in this chapter. In that capacity the Benefits Department is responsible for vendor management and oversight, audits of plan offerings and benefit related calculations, preparation and review of legally required notices and filings related to each plan. The Benefits Department staff also work with employees and retirees directly when there are escalated issues regarding plan eligibility and rules.³²²⁰

The Benefits Department forecast for 2023 is \$2.3 million, a \$1.0 million increase, compared to 2020 recorded adjusted.³²²¹ The primary drivers of the 2023 forecast are:

- (1) Labor Escalation - \$164 thousand based on the labor escalation factors provided in PG&E-8, Chapter 4;³²²²
- (2) Staffing Costs – a \$638 thousand increase in staffing costs compared to 2020 recorded adjusted. PG&E is forecasting a decrease of one FTE in

3218 PG&E-08, starting on WP 7-17, Detailed Competitive Summary by Employee Category for the value of PG&E's employee benefits compared with cash compensation.

3219 PG&E-08, p. 5-4, lines 10-13.

3220 PG&E-08, p. 5-33, lines 21-29.

3221 PG&E-21, p. 5-4, Table 5-1, line 5.

3222 PG&E-08, WP 5, Vol I-3, for a detailed year-over-year explanation of changes.

2023 as compared to the end of 2020.³²²³ During 2020 the average headcount in the department was 12 employees, with 10 employees at the start of the year and fully staffed with 15 employees by the end of the year. The staffing cost increase reflects the full-year cost of the employees hired over the course of 2020;³²²⁴ and

- (3) Contracts Costs - a \$126 thousand increase related to the increased cost to print and mail legally required notices to employees and retirees, updates to PG&E's benefit plans to meet changing regulatory and business needs, and the movement of benefits related work from HR Service Delivery & Inclusion to the Benefits team.³²²⁵

No parties contested the department cost forecast.

8.4.2 Companywide Expenses (Benefit Plans)

8.4.2.1 Summary of PG&E's Benefit Plans

PG&E offers an array of benefit plans in to attract and retain the workforce necessary to deliver services to PG&E's customers in what continues to be a competitive marketplace. Throughout the pandemic, technology and other bay area companies continued to offer skilled workers diverse employment options. PG&E's compensation and benefits package must be attractive to workers just entering the workforce, mid-career professionals, and those employees who are well into their careers. If PG&E were to offer a less competitive package, it could negatively impact the Company's ability to attract and retain employees.³²²⁶

Apart from the compensatory element of its benefit plans, PG&E's plan designs also serve broader customer objectives. For example, plans that promote health maintenance and disease prevention are essential to our ability to keep a diverse, skilled, experienced and dedicated staff healthy and focused on delivering safe and reliable service to its customers.³²²⁷

³²²³ PG&E-08, WP 5, Vol 1-8, line 2.

³²²⁴ PG&E-08, WP 5, Vol I-3, for a detailed year-over-year explanation of changes.

³²²⁵ PG&E-08, WP 5, Vol I-3, for a detailed year-over-year explanation of changes.

³²²⁶ PG&E-08, p. 5-4, lines 16-24.

³²²⁷ PG&E-08, p. 5-4, lines 25-29.

Several Advanced Utilization Management programs have been added to the portfolio. These programs provide additional safeguards that improve employees and dependents' health, improve outcomes, and reduce costs in targeted areas. The programs are discussed in additional detail below. PG&E is aware that customers have an interest in assuring that these plans, and especially health plans, are managed efficiently. Improving employee health not only has direct operational benefits by reducing unplanned absences and increasing the ability of employees to perform their job, a healthy workforce also helps control medical costs. A key component of PG&E's medical plan strategy is a single medical plan design that allows employees and their covered dependents to take more responsibility for their own good health through a focus on preventative care.³²²⁸

PG&E offers health and welfare benefits, including medical, dental, vision and Group Life and Accidental Death and Dismemberment (AD&D)³²²⁹ and a variety of post-retirement benefits. It provides other miscellaneous for current employees including relocation, service awards, family support, adoption and commuter transit benefits.

PG&E is aware that customers have an interest in assuring that these plans, and especially health plans, are managed efficiently. Improving employee health not only has direct operational benefits by reducing unplanned absences and increasing the ability of employees to perform their job, a healthy workforce also helps control medical costs. A key component of PG&E's medical plan strategy is a single medical plan design that allows employees and their covered dependents to take more responsibility for their own good health through a focus on preventative care.

³²²⁸ PG&E-08, p. 5-5, lines 1-12.

³²²⁹ PG&E-08, p. 5-3, lines 2-7.

PG&E's benefit plan design continues to be based on improving the health (physical, financial and emotional) and safety of its workforce, as well as the necessity to provide competitive compensation to attract and retain employees.³²³⁰

8.4.2.2 PG&E's Total Compensation Study Reflects The Value Of Employee Benefits

PG&E's cost of providing benefits to its employees is driven largely by individual benefit plan design. These benefit programs continue to evolve with the changing requirements of the workforce, regulatory and legislative mandates, and the competitive marketplace.³²³¹

PG&E's benefits programs are a significant and valued component of a total compensation package. As described in the Total Compensation Study, PG&E's total compensation is within the competitive range of benefits offered by competing firms in today's marketplace.³²³² Reductions in the benefits programs would lead to PG&E's total compensation package becoming less competitive and less attractive as compared to alternatives. This could impact staffing and, ultimately, customer service.

8.4.2.3 Employee Benefits Are A Key Component Of Labor Negotiations

Over 60% of PG&E's employees are represented by one of three labor organizations: The IBEW Local 1245, ESC Local 20, and the SEIU (collectively "the Unions"). For union-represented employees, benefit plan provisions are both an important component of the total compensation package and an integral component of the overall labor contract between the union and the Company. While total compensation is an important measure of the market, other factors can take precedence during the collective bargaining process, including specific benefit plans offered and employees contributions toward those plans. In March 2020, the 2012 union agreements with the IBEW Local 1245 and the ESC Local 20 were extended to December 31,

³²³⁰ PG&E-08, p. 5-5, lines 13-16.

³²³¹ PG&E-08, p. 5-5, lines 19-22.

³²³² PG&E-08, p. 7-8, lines 23-27.

2025. As part of that agreement, PG&E agreed to maintain the existing benefit plans, including Health Reimbursement Account (HRA) medical plan and deductibles, employee out of pocket maximums, employee contributions medical insurance copayments, and retirement plans. ³²³³

8.4.2.4 Benefits Forecast

Based upon the projected health, retirement and other benefit expenses, enrollment data as of January 1, 2021 and the headcount forecast through 2023, PG&E forecasts a 2023 total companywide expense of \$690.1 million.³²³⁴ This is a 29% increase over 2020 recorded adjusted costs of \$535.0 million, which were \$19 million less than the 2019 recorded adjusted costs. The decrease in 2020 costs was due to the coronavirus (Covid-19) pandemic, in particular, medical, dental and vision programs where spending is forecast to recover as the pandemic ends.³²³⁵ PG&E's forecast for certain Active Employee Health and Welfare Benefits, Post-Retirement Benefits, and Other Benefit Programs are uncontested. See Appendix A.

Pursuant to Resolution E-4963 (December 14, 2018), the 2023 forecast does not include benefits for the utility's Securities and Exchange Commission (SEC) Rule 240.3b-7 officers. PG&E has also voluntarily excluded from its 2023 forecast to the salary and benefits of the PG&E Corporation's SEC Rule 240.3b-7 officers although not required by the Resolution. See Exhibit (PG&E-8), Chapter 4 for further discussion of officer compensation costs. The specific adjustment is shown in the workpapers (WP) for all relevant plans.³²³⁶

8.4.2.4.1 Forecast Drivers And Methodology

Medical plan costs represent the largest part of the overall benefit plans forecast. The Medical Programs cost for 2023 are forecast to be \$535.8 million for the self-funded medical

³²³³ PG&E-08, p. 5-5, line 29 to p. 5-6, line 11.

³²³⁴ PG&E-21, Table 5-8, p. 5-25, line 25 (Total Health & Welfare: \$536.3 million) and p. 5-26, line 58 (Total Post Retirement: \$145.7 million) and p. 5-27, line 83 (Total Other Benefits: \$8.1 million) = \$690.4 million.

³²³⁵ PG&E-08, p. 5-1, line 28 to p. 5-2, line 4.

³²³⁶ PG&E-08, p. 5-2, lines 5-12.

plans and fiduciary compliance and administration costs.³²³⁷ Examples of fiduciary compliance and administration costs include: legally required audits, legally required benefit communications, third-party vendor administrator and record-keeping fees, health plan underwriting, and Consolidated Omnibus Budget Reconciliation Act (COBRA) healthcare continuance cost. Also included are outsourced costs associated with Health and Welfare administration with Morneau Shepell. The forecast is based on an actuarial study to determine expected medical claims and related costs adjusted for the forecast change in employee headcount and assumes that fiduciary compliance and administrative costs will increase with escalation.

8.4.2.4.2 Use Of An Actuarial Forecast Is The Appropriate Methodology

The use of a medical cost trend developed specifically to forecast expected PG&E experience is consistent with the approach used in PG&E's 2014, 2017 and 2020 GRCs and typical of how large employers with both insured and self-funded medical plans forecast costs.³²³⁸ There is no single cause for increases in annual medical costs. Instead, medical plan costs are influenced by many factors including medical inflation rates, integration of benefit plan design, plan enrollment, participant demographics/health status, legislative mandates, and plan cost-sharing.³²³⁹ As such, it is appropriate to use an estimating methodology that relies on forecasts provided by an actuarial consulting firm experienced in forecasting medical cost trends specific to large employer-sponsored plans, has knowledge of the Northern California medical provider marketplace and PG&E's medical plans specifically.³²⁴⁰

³²³⁷ PG&E-08, WP 5, Vol I-11.

³²³⁸ D.14-08-032, p. 530. "The approach used is typical of how large employers with both insured and self-funded medical plans forecast health care costs."

³²³⁹ PG&E-08, p. 5-12, lines 4-8.

³²⁴⁰ PG&E-08, p. 5-12, lines 15-20.

In preparing PG&E's healthcare cost of medical plans forecast, PG&E engaged Mercer, an actuarial consulting firm. Mercer considered PG&E-specific workforce demographics, historical utilization data, medical plan design, PG&E's participation in the Willis Towers Watson Prescription Drug Collaborative for pharmacy benefit management services, and underlying enrollment information as of December 31, 2020.³²⁴¹ Mercer also reviewed national trend factors from historic and current Mercer national survey reports of large employers, California employers and Utilities, as benchmarking references.³²⁴²

The health care actuaries at Mercer produced their healthcare forecast based on their underwriting guidelines and the following: (1) PG&E's actual health care claims experience through December 31, 2020; (2) PG&E specific workforce demographics and the December 01, 2020 enrollment data; and (3) an assumed 4.0% medical plan cost trend (medical escalation rate) for 2020 and 2021.³²⁴³ Mercer also forecast that PG&E's medical plan costs after 2021 will be 4.5% for 2022 and 2023.³²⁴⁴ Details regarding the specific estimating methods and data sources used to develop these forecasts are provided in the workpapers.³²⁴⁵ The estimates were developed using generally accepted actuarial and underwriting practices and methods.

PG&E adjusted the Mercer actuarial forecast for planned changes in employee headcount, factoring in the lag in enrollment drops due to the required offering of benefits under COBRA. PG&E's 2023 medical plan forecast was increased by 8.0% due to the forecast increase in employee headcount as compared with 2020.³²⁴⁶

³²⁴¹ PG&E-08, p. 5-12, lines 21-27.

³²⁴² PG&E-08, WP 5, Vol I-16 to WP 5 Vol 1-22.

³²⁴³ PG&E-08, WP 5, Vol I-24.

³²⁴⁴ PG&E-08, WP 5, Vol I-24.

³²⁴⁵ PG&E-08, WP 5, Vol I-24 to WP 5 Vol 1-27.

³²⁴⁶ The employee headcount included regular and hiring hall (temporary represented) employees as all are eligible to participate in a medical plan.

8.4.2.4.3 The Impact Of The COVID-19 Pandemic On PG&E's Medical Costs

The COVID-19 pandemic has had a significant impact on the healthcare system and is forecast to continue to impact plan costs in 2021 and 2022.³²⁴⁷

Starting in March 2020, through the end of the year, PG&E saw a significant decrease in health care utilization, that led to lower than expected costs. Some of this care was postponed until later in 2020, or into 2021 or 2022. The most significant reductions were in April and May 2020. The reduction in care was slightly offset partially by an increase in costs due to COVID-19 testing and treatment.³²⁴⁸

Although a vaccine became available in December 2020, we expect COVID-19 to continue to impact health plan costs through 2022. With the current accelerated vaccination schedule, it is very reasonable to expect that healthcare costs will return to “normal,” that usage consistent with historic trends by 2023.³²⁴⁹

8.4.2.4.4 Medical Programs Management And Cost Control Efforts

PG&E remains committed to a proactive preventive approach to improving the health of employees and their dependents and quality of care in the face of escalating health care costs. Like many employers, PG&E has focused on several different strategies to address the root causes of health care cost increases. These strategies have included changes to plan design, vendor management and increased efforts to provide accessible health resources and information.³²⁵⁰ Several Advanced Utilization Management programs were added to the portfolio including AIM Musculoskeletal Pain Management; Telehealth covered at in-network

³²⁴⁷ PG&E-08, p. 5-11, lines 18-20.

³²⁴⁸ PG&E-08, p. 5-11, lines 21-27.

³²⁴⁹ PG&E-08, p. 5-11, line 28 to p. 5-12, line 2 (referencing PG&E-08, WP 5, Vol I-17, the plan actuary specifically addressed that they have accounted for the impact of the Covid-19 pandemic on the 2023 forecast.)

³²⁵⁰ PG&E-21, p. 5-8, lines 4-11. These include the services provided under the Wellness Program umbrella managed by the Safety Department whose continued implementation is assumed.

level; Advanced Opioid Management Program; expanded patient management, prior authorization, and Step Therapy.³²⁵¹

To ensure that the health plans are cost effective, PG&E regularly renegotiates fees and contractual performance guarantees with plan vendors to measure the level of service that is provided to its members and has regular meetings with vendors to review claims reports and measures of administrative performance. PG&E's Corporate Accounting Department and Planning, Forecasting and Reporting Departments regularly review all benefit program costs and work with program managers to research variances.³²⁵²

PG&E's Express Scripts contract includes rebates for certain drugs purchased by the health plan and employees, in 2020, PG&E received prescription drug rebates of \$9.0 million.³²⁵³ In addition, PG&E has an ongoing eligibility verification process to help ensure that every PG&E health care plan enrollee who receives benefits is entitled to those benefits.³²⁵⁴

These steps support our ongoing efforts to address health care cost escalation, increase medical costs transparency, and provide employees with tools/resources so they can make informed healthcare decisions to maintain and improve their health and mitigate health-related safety risks.³²⁵⁵

³²⁵¹ See PG&E-08, p. 5-7, line 16 to p. 5-8, line 14 for additional information about these programs.

³²⁵² PG&E-08, p. 5-8, lines 14-23.

³²⁵³ PG&E-08, p. 5-9, lines 1-3.

³²⁵⁴ PG&E-08, p. 5-9, lines 4-6.

³²⁵⁵ PG&E-08, p. 5-9, lines 7-11.

8.4.2.5 Cal Advocates' Significant Proposed Reductions To The Medical Plans Forecast Should Not be Adopted.

Cal Advocates proposes a 2023 forecast of \$401.6 million,³²⁵⁶ which is a \$134.2 million (approximately 25%) reduction to PG&E's forecast. The basis of Cal Advocate's recommendation is that the Commission should use a 5-year average of historic costs for the forecast in place of the actuarial analysis Mercer prepared to forecast medical plan costs.³²⁵⁷ The Commission should not adopt Cal Advocates' recommendation for the following reasons.

First, as discussed above, the use of an actuarial forecast including a medical cost trend developed specifically to forecast expected PG&E experience is consistent with the approach used in PG&E's 2014, 2017 and 2020 GRCs and, as the Commission has recognized, is typical of how large employers with both insured and self-funded medical plans forecast costs.³²⁵⁸ The forecast provided by PG&E's actuaries evaluates and considers medical cost trends specific to large employer-sponsored plans, and considers the Northern California medical provider marketplace and PG&E's specific medical plans.³²⁵⁹ In PG&E's 2020 GRC, Cal Advocates did not oppose PG&E actuarial based Medical Program forecast.³²⁶⁰

Second, the use of a historical average as Cal Advocates proposes, fails to account for several factors that affect the forecast cost of medical plans, which the actuarial forecast does address, including:

- Medical Cost Escalation:³²⁶¹ Using a 5-year average would underfund PG&E's plan because that data set includes no adjustments or accounting for medical escalation. As PG&E's actuary demonstrated in its report, Medical escalation trends have continued. PG&E's workpapers provided the Mercer forecast, which

³²⁵⁶ CALPA-11, p. 35, line 19 to p. 38 line 8, and Table 11-16.

³²⁵⁷ CALPA-11, p. 38, lines 5-8.

³²⁵⁸ See, e.g., D.14-08-032, p. 530. "The approach used is typical of how large employers with both insured and self-funded medical plans forecast health care costs."

³²⁵⁹ PG&E-08, p. 5-12, lines 9-20.

³²⁶⁰ A.18-12-009, Hearing Exhibit (HE)-196: Cal Advocates-15, p. 26, lines 9-11.

³²⁶¹ PG&E-21, p. 5-12, lines 17-25.

included benchmark and other data used to develop the medical escalation forecast used by PG&E. Mercer showed that from 2017-2020 there was a median 3.7% per year increase in medical costs using Northern California benchmarks and 3.8% median increase using utility benchmarks.³²⁶²

- Impact of COVID-19 on Historic Costs: Using a 5-year average would underfund PG&E's plans because historic costs for some years was significantly lower than typical because of the COVID-19 pandemic. As discussed above, starting in March 2020, through the end of the year, PG&E saw a significant decrease in health care utilization, that led to lower than expected costs.³²⁶³ Healthcare costs began to rebound in 2021, although as the pandemic has continued longer than was anticipated at the time of PG&E's original testimony, the rebound has been slower than expected. PG&E's 2021 Medical Program costs alone increased to \$452.3 million.³²⁶⁴ While a 5-year average methodology fails to account for this significant factor, the 2023 actuarial forecast provided by Mercer in 2020 assumed that the pent-up demand for medical and other health care services that resulted from the COVID-19 closures would occur in 2021 and 2022 and that by 2023 there would be no lingering impacts resulting from the COVID-19 pandemic. Specific COVID-19 adjustments were shown in the workpapers provided by Mercer.³²⁶⁵
- Impact of COVID-19 on Future Costs: Cal Advocates states PG&E is not required to cover COVID-19 costs including co-pays, co-insurance, and deductibles for COVID-related screening and testing, which were the subject of California waivers for insurers.³²⁶⁶ That is incorrect. As a self-funded plan, any mandates that do apply must be covered and paid for by the Company. As COVID-19 is here with us for the foreseeable future, PG&E's Medical plans will be required to continue to cover the COVID-related items. While this increase was not known at the time PG&E's 2023 GRC forecast was made, this virus will continue to put pressure on PG&E's Medical costs³²⁶⁷.
- Headcount: Cal Advocates makes no adjustment in their forecast to account for the increased number of employees PG&E is forecasting. PG&E's employee headcount, eligible for Medical benefits increased from 23,399 in December 2017 to 24,994 employees in December 2020. PG&E's forecast includes additional

³²⁶² PG&E-08, WP 5, Vol I-18.

³²⁶³ PG&E-08, p. 5-11, lines 18-24.

³²⁶⁴ PG&E's Email Transmittal of the 2021 Recorded Expense and Capital Data to Service List A.21-06-021. (Mar. 9, 2022) p. 26, line 24.

³²⁶⁵ PG&E-08, WP 5, Vol I-27.

³²⁶⁶ CALPA-11, p. 36, lines 21-23.

³²⁶⁷ PG&E-21, p. 5-11, lines 9-14.

employee headcount increases, 27,587 in 2023. This headcount increase results in a \$39.8 million increase in 2023 over the base forecast provided by Mercer.³²⁶⁸

Third, in support of its recommendations, Cal Advocates' comments that it did not have sufficient time to review PG&E's recorded 2021 data. PG&E provided its 2021 recorded data to Cal Advocates on March 09, 2022 consistent with the schedule set forth by the ALJ in this proceeding.³²⁶⁹ That was approximately 3 months before intervenor testimony was due to be served on June 13, 2022.³²⁷⁰

For the foregoing reasons the Commission should not deviate from the commonly-accepted practice of forecasting medical costs based on actuarial analysis.³²⁷¹ Cal Advocates' recommendation for significant reductions to PG&E's forecast based on using a 5-year average of historic costs fails to account for several important drivers of the cost forecast that the actuarial analysis addresses. Those recommendations would significantly underfund PG&E's medical plans, which are critical to the health and welfare of PG&E's employees and also to employee attraction and retention. The Commission should reject Cal Advocates' recommendation and adopt PG&E's medical plan forecast as presented and without modification.

8.5 PG&E Academy

PG&E Academy develops and delivers technical, safety, and other training that helps to maintain a skilled, safe, and qualified workforce. Developing and delivering training to new and

³²⁶⁸ PG&E-08, WP 5, Vol I-15, line 25.

³²⁶⁹ A.21-06-021 (PG&E TY 2023 GRC) Email Ruling Addressing Pending Motions & Request to Modify Schedule and Adopting Revised Schedule (April 12, 2022).

³²⁷⁰ PG&E-21, p. 5-11, lines 23-28.

³²⁷¹ See, e.g., D.14-08-032, p. 530 ("The approach used is typical of how large employers with both insured and self-funded medical plans forecast health care costs.").

existing employees is one means by which HR directly supports the delivery of safe and reliable services to customers.³²⁷²

PG&E has been recognized as having one of the top training organizations in the world, including two consecutive years for being recognized for Gas Operations Enhanced Field Scheduling (2017), and Becker Valve Simulation (2018) for outstanding gas training initiative of the year by *Training Magazine*, published by The Lakewood Group, LLC.³²⁷³

In 2020, based on priorities established by the lines of business (LOB), PG&E Academy developed or updated approximately 350 courses³²⁷⁴ to reflect new or changing laws, regulations, business procedures, and maintained or updated PG&E's state-certified apprentice programs. PG&E Academy also delivered in 2020, over 3,800 instructor-led training sessions, for approximately 390 different course codes, in areas such as electric operations, gas operations, and safety and compliance. The instructor-led training sessions represented over 48,000 student days (one student day equals one student in one eight-hour day of training). In addition, PG&E Academy offered approximately 500 separate web-based training or virtual learning course codes, which totaled over 19,000 student days.³²⁷⁵ These courses covered a wide range of disciplines across many technical specialties, including compliance, emergency response, system operations and maintenance (O&M), and hazardous energy control.³²⁷⁶

³²⁷² PG&E-08, p. 6-1, lines 5-9.

³²⁷³ PG&E-08, WP 6-34 to WP 6-40, as published by Training Magazine. Top companies were determined based on several factors, including the scope of training programs, linkage of training efforts to business goals, and effectiveness of programs.

³²⁷⁴ Additional courses were developed or maintained as a one-time technology update or delivery format change as a result of COVID.

³²⁷⁵ In addition to PG&E Academy training, approximately 20,000 Non-Academy web-based training or virtual student days were offered that utilized Academy infrastructure.

³²⁷⁶ Additional information about PG&E Academy activities can be found throughout PG&E-08, Ch. 6.

8.5.1 Department Costs

PG&E Academy department costs include the development and delivery of all types of training to support the Electric and Gas LOBs, as well as safety and compliance, enterprise systems and other functions.³²⁷⁷ PG&E's TY 2023 expense forecast for department costs as reflected in rebuttal testimony is \$38.3 million.³²⁷⁸ This is a \$1.2 million decrease (approximately 3%), as compared to 2020 recorded adjusted costs.³²⁷⁹

PG&E capital expenditures forecast as reflected in PG&E's rebuttal testimony is \$1.0 million in 2021, \$1.0 million in 2022, and \$1.0 in 2023.³²⁸⁰ The forecast for 2023 is a \$43 thousand decrease from the 2020 recorded adjusted costs. These costs are for tools, equipment, and maintenance of PG&E's learning facilities.³²⁸¹ PG&E's capital forecast is uncontested. See Appendix A.

Both Cal Advocates and the Engineering and Scientists of California Local 20 (ESC) made recommendations with respect to PG&E Academy department costs as discussed below:

8.5.1.1 Cal Advocates' Recommended Reductions To The PG&E Academy Forecast Should Not Be Adopted

Cal Advocates recommends a \$0.5 million reduction to the PG&E Academy department costs. Cal Advocates states that due to the variability of the historical data, a 5-year average for PG&E Academy A&G Salaries should be used as its 2023 forecast.³²⁸²

³²⁷⁷ PG&E-08, p. 6-3, lines 7-9; p. 6-4, Figure 6-1.

³²⁷⁸ PG&E-21, p. 6-3, Table 6-1, line 15.

³²⁷⁹ PG&E-08, p. 6-2, lines 22-24.

³²⁸⁰ PG&E-21, p. 6-14, Table 6-5, line 3.

³²⁸¹ PG&E-08, p. 6-2, lines 27-30. Additional information about these capital costs can be found in PG&E-08, p. 6-19, line 3 to p. 6-20, line 19.

³²⁸² CALPA-11, p. 51, lines 5-7.

PG&E's 2023 forecast is based on 2020 recorded costs plus standard labor escalation.³²⁸³ Cal Advocates used a 5-year average of nominal dollars to calculate the 2023 forecast for salaries,³²⁸⁴ which does not account for labor escalation. Even if the 5-year average forecast methodology was used, which PG&E does not agree would be appropriate, the amount forecast should be calculated using the average of base year dollars and then escalated to 2023.³²⁸⁵ That would result in a salaries forecast of \$6.51 million, which is higher than the \$6.04 million included in PG&E's 2023 forecast.

The Commission should not adopt Cal Advocates' recommendations. Cal Advocates has not demonstrated that PG&E's forecast methodology is unreasonable or incorrect. Further, correctly applied, Cal Advocates' recommendations would actually result in increases to PG&E's forecast.

8.5.1.2 The Commission Should Adopt The PG&E/ESC Memorandum of Understanding (MOU) Resolving PG&E Academy Issues

ESC supported PG&E's requested forecast for Academy Electric and Gas Training but proposed an increase in the allocation of funds to the PG&E Academy to support trainings for PG&E's engineering staff. In total, ESC proposed an allocation of approximately \$3.0 million over the 4 year GRC cycle (2023-2026), which would have resulted in an allocation of \$725,347 to PG&E Academy for the 2023 test year.³²⁸⁶ ESC stated that the types of PG&E Academy trainings for engineering staff are not sufficient to meet their technical and professional needs³²⁸⁷ and recommended that PG&E offer four additional PG&E Academy trainings: (1) a training course to help prepare senior estimators for the associate distribution engineer (ADE)

³²⁸³ PG&E-08, p. 6-12, lines 13-14 and WP 6-15.

³²⁸⁴ CALPA-11, p. 51, line 6-7.

³²⁸⁵ The 5-year average would be calculated using PG&E-08, WP 6-2, average of line 1, multiplied by the 2023 escalation factor of 1.0993 found on line 8 of the same workpaper and Table 6-6.

³²⁸⁶ ESC-01, p. 2, lines 6-8; p. 3, Table 1.

³²⁸⁷ ESC-01, p. 4, lines 7-8.

test; (2) an ongoing training on PG&E's engineering design standards; as well as other professional development trainings; (3) a development software program training; and (4) a time management and communications skills building training.³²⁸⁸ ESC stated it believed that each of the four recommended trainings would necessitate one full-time-employee PG&E Academy instructor.³²⁸⁹ ESC also recommended PG&E provide additional training with respect to dissemination of engineering design standard changes.³²⁹⁰

PG&E disagreed with ESC's recommendation that an increase to the PG&E Academy forecast was necessary.³²⁹¹ PG&E noted that Electric and Gas Training Programs provide training courses on a wide range of technical topics, including engineering. PG&E delivers robust technical training programs through the Academy Electric Technical School and the gas training facilities, primarily the Gas Safety Academy; and PG&E Academy offers numerous professional development trainings, both instructor-led training and web-based training.³²⁹² With respect to the ADE test in particular, PG&E agreed that senior estimators could benefit from more robust training and preparation for the ADE exam and noted that the decision for PG&E Academy to create new training programs is made through a cross-functional training governance process.³²⁹³ PG&E had already begun offering an ADE test preparatory program during business hours, staffed with a newly created position.³²⁹⁴ PG&E also made a number of other recommendations regarding the ADE administration it believed could be made to better

³²⁸⁸ ESC-01, p. 2, lines 10-14.

³²⁸⁹ ESC-01, p. 3, lines 1-2.

³²⁹⁰ ESC-01, p. 8, line 5 to p. 9, line 3.

³²⁹¹ PG&E-21, p. 6-11, lines 12-19.

³²⁹² PG&E-21, p. 6-8, lines 17-23.

³²⁹³ PG&E-21, p. 6-9, lines 5-8.

³²⁹⁴ ESC-01, p. 5, line 19-21.

support test takers.³²⁹⁵ PG&E disagreed that a separate training course was required with respect to engineering design standard changes and described other ways in which such information can be effectively communicated.³²⁹⁶

PG&E and ESC were able to work together to negotiate an MOU that resolves all issues between the parties with respect to PG&E Academy which they submitted on September 16, 2022.³²⁹⁷ Among other things, the MOU provides that: (1) PG&E will conduct preparation sessions for each gas and electric ADE exam given in 2023-2026 substantially similar to the ADE exam preparation sessions provided in 2021;³²⁹⁸ (2) PG&E will provide five hours per week of paid study time to each student enrolled in the Estimator Training Program and New Business Representative training programs;³²⁹⁹ and (3) PG&E and ESC mutually commit to work cooperatively to improve, modernize, and enhance the effectiveness of end-to-end training, testing, and professional development of employees covered by the contractual training programs for certain job classifications.³³⁰⁰

8.6 Total Compensation Study

PG&E's compensation policy is to provide cash compensation that is competitive with the relevant job market and that reflects the job that the individual employee performs. The market and job specific considerations include required experience and expertise as well as the

³²⁹⁵ PG&E-21, p. 6-9, line 25 to p. 6-10, line 13.

³²⁹⁶ PG&E-21, p. 6-10, lines 17-27.

³²⁹⁷ *Joint Motion of Pacific Gas and Electric Company (U 39 M) and the Engineers and Scientists of California Local 20 to Admit Late Filed Exhibit Into Evidence* (Sept. 16, 2022) (hereafter "Joint Motion to Adopt PG&E/ESC MOU), Attachment A, Section 1.7.

³²⁹⁸ Joint Motion to Adopt PG&E/ESC MOU, Attachment A, Section 3.1.

³²⁹⁹ Joint Motion to Adopt PG&E/ESC MOU, Attachment A, Section 3.2.

³³⁰⁰ Joint Motion to Adopt PG&E/ESC MOU, Attachment A, Section 3.3.

cost of labor in the San Francisco Bay Area. PG&E continually evaluates its offerings to remain competitive.³³⁰¹

PG&E's employee cash compensation includes a mix of base pay and incentive compensation, with the proportion of incentive compensation increasing as an employee's level in the organization increases. Increasing the proportion of employee cash compensation tied to incentives at higher levels in the organization helps align the leaders' and their team's priorities with those of the broader organization.³³⁰² In addition, with over 60% of PG&E's employees represented by one of three labor unions,³³⁰³ much of PG&E's employee compensation is also dependent on reaching agreements with those unions that can be ratified by their members.

In accordance with Commission directives, PG&E hired an independent consulting firm—WTW—to perform the TCS for this GRC.³³⁰⁴ The TCS provides an independent analysis of the competitiveness of the Company's total compensation (cash compensation and benefits) compared to the relevant market. The TCS is provided as Chapter 7 of this exhibit. In the TCS, WTW found PG&E's 2020 target total compensation was competitive at 8.9% of the market.³³⁰⁵ No parties have disputed the accuracy of WTW's findings.

³³⁰¹ PG&E-08, p. 4-1, lines 24-29.

³³⁰² PG&E-08, p. 4-2, lines 1-6.

³³⁰³ Employees are represented by the International Brotherhood of Electrical Workers (IBEW) Local 1245, the Engineers and Scientists of California (ESC), Local 20 and the Service Employee International Union (SEIU).

³³⁰⁴ D.95-12-055, 1995 Cal. PUC LEXIS 965 *31-32, 63 CPUC2d 570.

³³⁰⁵ PG&E-08, p. 7-4. The Total Compensation Study is included as PG&E-08, Ch. 7. Additional information about the study methodology and results can be found in PG&E-08, Ch. 7, and in PG&E-08, p. 4-2, line 13 to p. 4-10, line 10.

9. ADMINISTRATIVE AND GENERAL EXPENSES (EXHIBIT PG&E-09)

Administrative and General (A&G) expenses support all of PG&E's lines of business (LOBs). The Commission has described A&G costs as follows:

A&G expenses are of a general nature and are not directly chargeable to any specific utility function. They include general office labor and supply expenses and items such as insurance, casualty payments, consultant fees, employee benefits, regulatory expenses, association dues, and stock and bond expenses.³³⁰⁶

A&G is comprised of Corporate Services that are essential to the operational LOBs' ability to deliver on their goals. For example, the Corporate Services organizations disseminate important information to customers and their local and state representatives regarding all manner of programs, services, safety initiatives, and emergency communications. They also allow PG&E to work effectively with its regulators and be responsive to their requests for information. In addition, A&G consists of services—such as those provided by our Law, Finance, and Risk and Audit departments—that support PG&E's electric distribution, gas distribution and energy supply functions and are critical to any business the size and complexity of PG&E.³³⁰⁷

9.1 Summary of Settlements And Stipulations

Cal Advocates and TURN addressed PG&E's A&G proposals. After developing their respective litigation positions through opening testimony, discovery, rebuttal testimony, and hearings, TURN, Cal Advocates and PG&E were able to collaboratively resolve the contested A&G through a stipulation as follows:

1. Wildfire Liability Insurance Settlement: PG&E, Cal Advocates and TURN have reached a settlement with respect to wildfire liability insurance issues, which, if adopted, will resolve all issues with respect to that program and forecast and will result in a \$307 million reduction to the 2023 corporate items forecast (Insurance Settlement).³³⁰⁸

³³⁰⁶ D.00-02-046, pp. 243-244.

³³⁰⁷ PG&E-09, p. 1-1, lines 15-24.

³³⁰⁸ *Joint Motion of Pacific Gas and Electric Company, The Utility Reform Network and The Public Advocates Office at the California Public Utilities Commission for Expedited Approval and Adoption of the Attached Settlement Agreement on Insurance Related Issues* (Joint Motion for Adoption of Insurance Settlement) (October 7, 2022), p. 9.

2. Stipulation on Remaining A&G Issues: With the exception of the wildfire liability insurance settlement, the remaining A&G contested issues were relatively small (A&G Stipulation). The A&G Stipulation is attached as Appendix G to this brief.

Table 9-1 below summarizes the resolution of each of the disputed A&G issues through the Insurance Settlement and A&G Stipulation.

**TABLE 9-1
PROPOSED RESOLUTION OF ALL DISPUTED A&G ISSUES**

Organization or Topic	Description	Forecast and Recommendation	A&G Stipulation	Brief Reference
Finance	Companywide Expense - Bank Fees	PG&E forecasts \$1.75 million. TURN recommends a \$1.5 million reduction to \$0.25 million to remove one-time costs forecast for 2023.	The forecast will be \$0.25 million.	Section 9.3.2
Risk Audit Insurance	Department Costs – Cost of 1 FTE	PG&E forecasts \$13.22 million for labor. Cal Advocates recommends a \$0.159 million reduction to remove the cost of one FTE Manager position forecast to support the department’s Third-Party Risk Management (TPRM) activities.	The forecast will be \$13.06 million.	Section 9.4.1.1
Risk Audit Insurance	Department Costs – Costs of Privileged Internal Audits	Cal Advocates proposes a reduction of \$0.1 million in 2018 and \$0.14 million in 2020 for the recorded costs of a privileged internal audit performed in each year.	No reductions will be made to PG&E’s forecast for this item.	Section 9.4.1.2
Risk Audit Insurance	Wildfire Liability Insurance	PG&E proposed \$707 million for 2023. Cal Advocates and TURN proposed \$354 million and \$333 million respectively.	The 2023 forecast will be \$400 million. The forecast for subsequent years will be subject to adjustment based on claims activity.	Section 9.4.2.2.1
Risk Audit Insurance	Insurance Forecasts (with the exception of Wildfire Liability Insurance)	PG&E forecasts \$199.575 million (Non-Wildfire Liability, D&O, Other Liability, Nuclear Property, Non-Nuclear Property, Other Property, and the PG&E Corporate Allocation). No parties dispute the amount of PG&E’s forecast.	The forecast will be \$199.575 million.	Section 9.4.2.1; Section 9.4.2.2.2
Risk Audit Insurance	Two-way Risk Transfer Balancing Account	PG&E proposes that the RTBA should apply to non-wildfire liability insurance. TURN proposes that the	The RTBA will apply to the cost of procuring up to \$700 million of non-wildfire liability	Section 9.4.2.6

Organization or Topic	Description	Forecast and Recommendation	A&G Stipulation	Brief Reference
	(RTBA) for Non-Wildfire Liability Insurance	RTBA should not apply to that forecast under its current terms.	insurance. If the cost of that insurance is less than PG&E's forecast, PG&E will return to ratepayers in the next annual RTBA true-up the difference between the amount collected and amount incurred. If annual incurred costs are above the forecast amount, PG&E is permitted to seek recovery of such costs by application.	
Law	Companywide Expense – Settlements, Judgments and Claims	PG&E forecasts \$36.38 million based on a 3-year average forecast methodology. Cal Advocates recommends a \$3.2 million reduction (\$31.44 million) to PG&E's forecast based on using a 4-year average forecast methodology.	The forecast will be \$33.9 million.	Section 9.7.2
Executive Offices and Corporate Secretary	Companywide Expenses – Director Fees and Expenses	PG&E forecasts \$2.44 million. TURN recommends \$1.22 million.	The forecast will be \$1.83 million.	Section 9.8.2
Update Testimony	Testimony Reflecting Updated Escalation Indices Per the Rate Case Plan	PG&E filed update testimony that adjusted GRC forecasts to reflect updated cost escalation indices.	The wildfire liability insurance settlement is not affected by this item. The remaining stipulated forecasts described in this Table will be subject to further adjustment based on the resolution of PG&E's update filing.	Section 13

PG&E discusses each of these items and the stipulated resolutions in greater detail in the sections that follow. The A&G Stipulation reflects a compromise of disputed litigation positions on a range of A&G issues that should be approved in its entirety without modification.

9.2 Forecast

This section includes a summary of PG&E's forecasts as presented in its rebuttal testimony and the Joint Comparison Exhibit (PG&E-64). Additionally, it describes the updated forecast that accounts for the settlements and stipulations described in Section 9.1 above.

9.2.1 Summary Of The Forecast

PG&E forecast expenses of \$1,110.9³³⁰⁹ million for test year 2023, a decrease of \$12.2 million compared to the 2020 recorded adjusted amount of \$1,123.2 million.³³¹⁰ PG&E's JCE forecast is and \$1,115.4 million in 2023.³³¹¹ Certain costs of PG&E's forecast are uncontested. Approximately \$140.7 million, 91 percent,³³¹² of PG&E's department cost forecast is uncontested and approximately \$608.3 million, 64 percent, of PG&E's companywide expense forecast is uncontested or settled.³³¹³

PG&E's capital expenditures forecast to support Corporate Services IT Programs as reflected in rebuttal testimony is \$0.1 million in 2021, \$3.0 million in 2022, and \$2.5 million in 2023, \$2.5 million in 2024, \$2.5 million in 2025, and \$2.5 million in 2026.³³¹⁴ PG&E's capital

3309 PG&E-22, p. 1-6, Table 1-4, line-8 (Department Expenses: \$153.892 M), p. 1-7, Table 1-5, line 10 (Companywide Expense: \$955.516 M); p. 1-8, Table 1-6, line 8 (IT Expenses: \$1.540 M) = \$1,110.948 M.

3310 PG&E-22, p. 1-6, Table 1-4, line-8 (Department Expenses: \$163.252 M), p. 1-7, Table 1-5, line 10 (Companywide Expense: \$957.785 M); p. 1-8, Table 1-6, line 8 (IT Expenses: \$2.138 M) = \$1,123.175 M.

3311 PG&E-64, p. 3-18, Table 3C-1, lines 22-30 (Department Expenses and IT: \$159.015M) and p. 3-19, Table 3C-1, lines 71-87 (Companywide Expenses: \$956.398 M) = \$1,115.413 M.

3312 See Appendix A, p. A-24, line 8 (calculated as \$140.7 (uncontested amount) / \$153.9 (total forecast) = 91%).

3313 See Appendix A, p. A-26, line 34 (calculated as \$208.3 (uncontested amount) + \$ (400 settled amount) = \$608.3 / \$955.5 (total forecast) = 64 percent. Settled amounts are discussed in Section 9.4.2.2.1.

3314 PG&E-22, p. 1-9, Table 1-7, line 8 (2020-2023) and PG&E-9, p. 1-14, Table 1-6, line 8 (2024-2026).

forecast is uncontested.³³¹⁵ PG&E's JCE forecast is \$0.1 million in 2021, \$3.5 million in 2022, \$3.0 million in 2023, \$3.0 million in 2024, \$3.0 million in 2025, and \$3.0 million in 2026.³³¹⁶

Forecast expenses include department costs, companywide expenses and information technology expense, each of which is summarized below.

The forecasts for corporate services organizations include significant headcount reductions in the aggregate. In many cases, organizations are forecasting net decreases in department costs or are otherwise managing their costs within the scope of general labor escalation. Additionally, PG&E, Cal Advocates and TURN have reached a settlement with respect to wildfire liability insurance issues, which, if adopted, will result in an additional \$307 million reduction to the 2023 corporate items forecast.³³¹⁷ The settlement is addressed in the Companywide Expenses summary below and in more detail in Section 9.3.2.2.1.

PG&E's A&G forecast consists of three types of costs:

1. Corporate Services Department Costs: (\$153.9 million).³³¹⁸ Department costs are for support services necessary for day-to-day operations.³³¹⁹ The Department cost forecast is \$9.4 million (almost 6 percent) lower than 2020 recorded adjusted costs of \$163.3 million.³³²⁰ Contract reductions represent the largest area of cost decreases among A&G organizations. The overall \$15.2 million contract costs decrease is approximately

³³¹⁵ Appendix A, p. A-24, line 157.

³³¹⁶ PG&E-64, p. 3-17, Table 3B-3, line 131 (2021); p. 3-13, Table 3B-2, line 131 (2022); p. 3-9, Table 3B-1, line 131 (2023) and PG&E-67, WP-4, line 9 Total (2024-2026); PG&E-22, p. 1-9, Table 1-9, line 8 (sum of totals for 2021, 2022 and 2023).

³³¹⁷ *Joint Motion of Pacific Gas and Electric Company, The Utility Reform Network and The Public Advocates Office at the California Public Utilities Commission for Expedited Approval and Adoption of the Attached Settlement Agreement on Insurance Related Issues* (Joint Motion for Adoption of Insurance Settlement) (October 7, 2022), p. 9.

³³¹⁸ PG&E-22, p. 1-6, Table 1-4, line 8.

³³¹⁹ PG&E-09, p. 1-1, lines 26-27.

³³²⁰ PG&E-22, Table 1-4, line 8.

9 percent from the 2020 recorded adjusted costs.³³²¹ Additionally, PG&E forecasts a decrease of approximately \$2.9 million compared to 2020 recorded adjusted costs associated with headcount reductions.³³²² Collectively, the A&G organizations are forecasting a total headcount reduction of 13 FTEs for 2023, which represents approximately 1.5 percent of the total A&G workforce compared to 2020 levels, as well as the absorption of the costs of filling an additional 7 vacant FTE positions in the Risk, Audit and Insurance.

Among other things, PG&E's A&G forecast includes labor costs, which are included in Federal Energy Regulatory Commission (FERC) Account 920. Consistent with the Commission's decision in SCE's 2021 GRC³³²³ and Resolution E-4963 (December 14, 2018), in preparing PG&E's forecast, PG&E excluded the salary and benefits of the utility's Securities and Exchange Commission (SEC) Rule 240.3b-7 officers. PG&E also voluntarily excluded from its 2023 forecast the salary and benefits of the PG&E Corporation's SEC Rule 240.3b-7 officers although not required by the Resolution. See Exhibit (PG&E-8), Chapter 4 for further discussion of officer compensation costs. To the extent such costs were included in the forecast for employee benefits, adjustments were made to remove costs associated with these officers.³³²⁴

2. Companywide A&G Expenses: (\$955.5 million):³³²⁵ Companywide expenses include forecasts for insurance premiums, settlements and judgments, fees, and other similar costs. PG&E's 2023 forecast is \$2.3 million lower than 2020 recorded adjusted costs of

³³²¹ PG&E-09, p. 1-4, lines 1-4.

³³²² PG&E-09, p. 1-5, Figure 1-2, p.1-6, lines 1-6.

³³²³ See, D.21-08-036, pp. 617-618, FOF 501-506.

³³²⁴ PG&E-08, p. 4-25, lines 3-26.

³³²⁵ PG&E-22, p. 1-7, Table 1-5, line 10. Note, the 2020 recorded costs include approximately \$360 million of one-time costs that are not expected to recur in 2023. PG&E's forecast is based on the cost of its most recent renewal from April 2021, which was the most recent cost data available. (PG&E-09, p. 3-2, lines 1-6).

\$957.8 million.³³²⁶ The forecast reflects the continuing, high cost of wildfire liability insurance in the third-party, commercial market. However, as discussed in more detail in Section 9.4.2.2.1 below, PG&E, Cal Advocates, and TURN have reached a settlement agreement on insurance-related issues, which, if adopted, would decrease PG&E's corporate items forecast by \$307 million for 2023.³³²⁷

3. Information Technology (IT) Project Costs: \$1.5 million expense and \$2.5 million capital for 2023.³³²⁸ These forecasts consist of IT projects designed to support the Corporate Services organizations. PG&E's 2023 forecast expense is \$0.6 million (approximately 28 percent) lower than 2020 recorded costs of \$2.1 million.

9.2.2 Updated Forecast Reflecting Settlements And Stipulations

PG&E's expense forecast in its rebuttal testimony is \$1,110.9³³²⁹ million for test year 2023. If adopted, the settlements and A&G Stipulation described in Table 9-1 above will reduce PG&E's 2023 TY expense forecast by \$404.48 million (approximately 36 percent) for a total forecast of \$706.42 million.

9.3 Finance Organization Costs

Our Finance organization provides the necessary financial capabilities found in any large, publicly-traded company. It is responsible for functions such as raising capital, communicating with investors, providing financial forecasts, filing financial statements with the Securities and Exchange Commission (SEC) and other regulatory bodies, making necessary tax filings with federal and state authorities, and managing payment services for employees and vendors. It also works with the other organizations within the Company to plan and manage budgets and improve

³³²⁶ PG&E-22, p.1-7, Table. 1-5, line 10.

³³²⁷ Joint Motion for Adoption of Insurance Settlement, p. 9.

³³²⁸ PG&E-09, p. 1-14, Table 1-6, line 8.

³³²⁹ PG&E-22, p. 1-6, Table 1-4, line-8 (Department Expenses: \$153.892 M), p. 1-7, Table 1-5, line 10 (Companywide Expense: \$955.516 M); p. 1-8, Table 1-6, line 8 (IT Expenses: \$1.540 M) = \$1,110.948 M.

processes and performance. The Finance organization works to provide these services efficiently, while continually adapting to changes in our business environment. The organization strives to continuously improve the efficiency and effectiveness of its processes and tools.³³³⁰

9.3.1 Department Costs

The Finance Department's department costs include the Chief Financial Officer, Business Finance, the Controller, Investor Relations, Treasury and Finance and Planning.³³³¹ As reflected in its Rebuttal Testimony, PG&E forecasts \$54.4 million³³³² for 2023. This 2023 forecast is approximately \$6.1 million (10.1 percent) lower than the 2020 recorded amount of \$60.6 million.³³³³ In 2020, the organization had 378 FTE positions. The Department's 2023 forecast includes a staffing reduction of 31 FTEs from 2020.³³³⁴ PG&E also forecasts an overall decrease in contract costs and fees driven by reductions for Controller contracts and outside services. These decreases are partially offset by an increase for labor escalation.³³³⁵ No parties have contested this forecast.

9.3.2 Companywide Expenses (Bank Fees)

Utility bank fees represent the fees charged for depository, disbursement, custody, and trustee-related services. Utility bank fees also include all fees associated with the Utility's working capital facilities. These costs are included in the estimate of bank fees recorded to FERC Account 930.³³³⁶

³³³⁰ PG&E-09, p. 2-1, lines 6-18.

³³³¹ Additional information about the Finance Organization's activities can be found throughout PG&E-9, Ch. 2.

³³³² PG&E-22, p. 2-3, Table 2-1, line 8.

³³³³ PG&E-09, p. 2-22, Table 2-1, line 8 (recorded); PG&E-22, p. 2-3, Table 2-1, line 8 (adjusted forecast).

³³³⁴ PG&E-09, WP 2-8, line 16.

³³³⁵ PG&E-09, p. 2-1, line 25 to p. 2-2, line 3; see also p. 2-18, line 28 to p. 2-19, line 19.

³³³⁶ PG&E-09, p. 2-19, lines 21-28.

PG&E's TY 2023 forecast for companywide expenses as reflected in rebuttal testimony is \$9.6 million.³³³⁷ PG&E's forecast of bank fees for 2023 is based on actual expenses in 2020 adjusted for any planned capital structure changes and anticipated changes in contract terms.³³³⁸

TURN is the only party addressing this issue and recommends a \$1.5 million reduction to PG&E's forecast.³³³⁹ TURN states that PG&E included \$1.5 million in Letter of Credit (LOC) fees associated with sale of the General Office complex in its 2023 forecast, which are not expected to recur beyond 2023. TURN states that this amount is a non-recurring cost that should be removed from rates.³³⁴⁰

PG&E accepts TURN's recommendation as described in Table 9-1 above.

9.3.3 Technology Projects

PG&E's TY 2023 expense forecast for information technology is \$0.5 million.³³⁴¹ These costs are forecasted in MWC JV (Maintain Applications and Infrastructure) and include costs for ongoing maintenance, operations, and repair for PG&E's applications, systems, and infrastructure, primarily to the SAP financial system. As part of the normal course of business, PG&E must upgrade and enhance its SAP financial system to maintain functionality and security. SAP is one of PG&E's most critical platforms and touches virtually all aspects of the Company's financial operations.³³⁴² No parties have contested this forecast.

³³³⁷ PG&E-22, p. 2-4, Table 2-2, line 5.

³³³⁸ PG&E-09, p. 2-19, line 28 to p. 2-20, line 1; see also PG&E-9, WP 2-77, which includes additional information about forecast methodology and assumptions.

³³³⁹ TURN-05, pp. 15-16.

³³⁴⁰ TURN-05, pp. 15-16, citing PG&E's response to TURN_067-Q01(b).

³³⁴¹ PG&E-22, p. 2-4, Table 2-3, line 2.

³³⁴² PG&E-09, p. 2-20, lines 5-16.

9.4 Risk, Audit And Insurance

Risk, Audit and Insurance is responsible for overseeing PG&E's Market and Credit Risk Management (M&CRM), Internal Audit (IA), Insurance and Loss Control, Sarbanes Oxley (SOX) compliance, and Third Party Risk Management (TPRM) and other functions that help the Company manage its key risks.³³⁴³

9.4.1 Department Costs

PG&E's TY 2023 expense forecast for department costs as reflected in rebuttal testimony is \$13.2 million.³³⁴⁴ The 2023 forecast is \$1 million (approximately 8.2 percent) higher than the 2020 recorded adjusted amount of \$12.2 million.³³⁴⁵ The increase is driven primarily by labor escalation, staffing, and is partially offset by lower staff augmentation and consulting service costs.³³⁴⁶

Included in PG&E's forecast was \$0.9 million to fill 14 vacant positions in 2023 for the M&CRM, Audit, SOX, TPRM and Insurance departments. The \$0.9 million forecast is approximately half of the total cost of filling the vacancies. PG&E will absorb the additional cost within its operating budget for 2023.³³⁴⁷ PG&E has provided testimony describing each of the vacant positions to be filled and the importance of the work those employees would perform in detail.³³⁴⁸ No parties have opposed PG&E's request with the exception of one position as described below.

³³⁴³ PG&E-09, p. 3-1, lines 5-9. Additional information about Risk and Audit's activities can be found throughout PG&E-09, Ch. 3.

³³⁴⁴ PG&E-22, p. 3-3, Table 3-1, line 3.

³³⁴⁵ PG&E-09, p. 3-49, Table 3-9, line 3 and Table 3-10, line 5.

³³⁴⁶ PG&E-09, p. 3-1, lines 23-26.

³³⁴⁷ PG&E-09, p. 3-8, lines 10-16.

³³⁴⁸ PG&E-09, p. 3-8, line 10 to p. 3-9, line 17; PG&E-09, WP 3-41 (provides additional information about these positions); PG&E-09, WP 3-85 (provides the job descriptions for these FTEs with the exception of Internal Auditor, Senior (Operational), which was being revised and was not included).

Cal Advocates proposes two reductions to the Internal Audit forecast: (1) a \$0.159 million reduction to remove the cost of one Full-Time Employee Program Manager position forecast to support the department’s Third-Party Risk Management (TPRM) activities;³³⁴⁹ and (2) a reduction of \$0.1 million in 2018 and \$0.14 million in 2020 for the recorded costs of a privileged internal audit performed in each year.³³⁵⁰

9.4.1.1 Internal Audit Staffing

Cal Advocates recommends a \$0.159 million reduction to remove the cost of filling one of the vacancies for Project Manager, Principal. PG&E accepts Cal Advocates’ recommendation as shown in Table 9-1.

9.4.1.2 Privileged Internal Audit Reports

Cal Advocates recommends a reduction of PG&E’s 2023 forecast based on arguments that amounts were incorrectly included in the data from which the 2023 forecast was derived. Cal Advocates suggests an adjustment of \$102,000 in 2018 and \$136,000 in 2020 with respect to the preparation of various internal audit reports that were subject to the attorney-client privilege.³³⁵¹ Cal Advocates states that it “does not challenge PG&E’s assertion of legal privilege. However, without access to the requested audit reports, Cal Advocates could not determine whether the costs to perform these internal audits were justifiably assigned to ratepayers.”³³⁵² Cal Advocates has stipulated that there should be no reduction to PG&E’s forecast for this item as described in Table 9-1.

³³⁴⁹ CALPA-12, p. 8, lines 9-14.

³³⁵⁰ CALPA-18, p. 1, lines 22-26; p. 9, line 10 to p. 12, line 13; and Table 18-6.

³³⁵¹ CALPA-18, p. 1, lines 22-26; p. 11, Table 18-6; please note Cal Advocates’ recommendation to reduce 2018 recorded costs, if adopted, would have no impact on PG&E’s 2023 forecast, which is based on 2020 recorded data.

³³⁵² CALPA-18, p. 9, lines 22-25.

9.4.2 Insurance

PG&E's TY 2023 forecast for companywide expenses as reflected in rebuttal testimony is \$907.1 million as indicated in Table 9-2 below.³³⁵³

TABLE 9-2
2023 INSURANCE FORECAST
(MILLIONS OF NOMINAL DOLLARS)

			PG&E-9	PG&E-22, p. 3-4, Table 3-2
Line No.	Insurance Type	2023 Forecast	Testimony Reference	Cost Table Reference
1	<u>Property Insurance</u>			
2	Non-Nuclear Property & Other	\$28.5	C.3.a.1.	Line 9
3	Nuclear Property	.1	C.3.a.2.	Line 7
5	<u>Liability Insurance</u>			
6	General Liability including: Excess Liability; and Other Liability	\$161.8	C.3.b.1.	Line 6 and 8
	Wildfire Liability Insurance	707.5		
7	Directors & Officers	6.4	C.3.b.2.	Line 5
8	PG&E Corporation Allocation	2.7	C.3.c.	Lines 1, 2, 3, and 4
9	Total	\$907.1		Lines 1-10

PG&E's 2023 insurance forecast is \$9.2 million lower than 2020 recorded adjusted costs of \$916.3 million.³³⁵⁴

One of the biggest drivers of the insurance forecast is the continuing, high cost of wildfire liability insurance in the third-party, commercial market. However, as discussed in more detail in Section 9.4.2.2.1 below, PG&E, Cal Advocates, and TURN have reached a settlement agreement resolving all issues with respect to PG&E's wildfire liability insurance program and forecast, which, if adopted, would decrease PG&E's insurance forecast by \$307 million for 2023 (Insurance Settlement).³³⁵⁵

Other non-wildfire drivers of the forecast include: (1) an increase in D&O liability premium costs due to tightening market conditions; (2) an increase in aviation insurance costs

³³⁵³ PG&E-22, p. 3-4, Table 3-2, line 11.

³³⁵⁴ PG&E-09, p. 3-50, Table. 3-11, line 20.

³³⁵⁵ Joint Motion for Adoption of Insurance Settlement, p. 9.

resulting from the purchase of additional aircraft and specialty equipment for pipeline and powerline inspections by PG&E coupled with a challenging insurance market; (3) an increase in non-nuclear property insurance costs due to a hardening market, separate coverage purchased for PG&E's corporate headquarters and increasing insured asset values; and (4) a decrease for nuclear property costs primarily due to distributions from an industry mutual insurance company and a reduction in property insurance limits carried on the nuclear assets at Humboldt Bay Power Plant (HBPP).³³⁵⁶ No parties have contested PG&E's forecast for its property insurance items or non-wildfire liability coverage. The forecasts PG&E presented for those items are reasonable and the Commission should adopt them as presented.

Finally, PG&E requested authority to continue the two-way RTBA as general liability insurance premiums for both wildfire and non-wildfire perils continue to be difficult to forecast accurately.³³⁵⁷ The Insurance Settlement resolves that issue with respect to PG&E's wildfire liability program. The A&G Stipulation resolves that issue with respect to PG&E's non-wildfire liability insurance program.

9.4.2.1 Property Insurance Forecast

9.4.2.1.1 Property Insurance (Non-Nuclear)

PG&E forecasts \$28.5 million for non-nuclear property insurance premiums in 2023, which is a 22 percent increase compared to 2020.³³⁵⁸ The forecast is based on PG&E's 2020 renewal cost which has been escalated by a factor of five percent each year through the 2023 Test Year.³³⁵⁹ The five percent escalation is conservative when compared to average price

³³⁵⁶ PG&E-09, p. 3-16, lines 1-11.

³³⁵⁷ PG&E-09, p. 3-16, lines 16-22.

³³⁵⁸ PG&E-09, p. 3-16, line 32 to p. 3-17, line 1; p. 3-50, Table 3-11, line 6.

³³⁵⁹ PG&E-09 at p. 3-17, lines 2-3.

increases expected in the markets during the same period.³³⁶⁰ No party has contested this forecast and the Commission should adopt it without modification.

This program provides coverage for the cost of repair and replacement of damaged PG&E property from perils such as storms, earthquakes, terrorism, and fires at PG&E's non-nuclear facilities.³³⁶¹ The property insurance market constricted following calendar year 2017 in which natural catastrophic activity reached historical levels for property insurers. The insurance markets have continued to experience elevated levels of global insured losses in subsequent years, including calendar year 2020 which is estimated to be the fifth-costliest year for public and private entities collectively.³³⁶² PG&E has experienced difficulty in procuring comparable amounts of financial protection as it carried in the past, and within previous forecasted amounts, as a result of these market conditions. PG&E plans to secure coverage amounts consistent with limits carried in the past if market conditions improve during the 2023 GRC period.³³⁶³

Cal Advocates, TURN, and PG&E have stipulated that this forecast should be adopted as described in Table 9-1.

9.4.2.1.2 Property Insurance (Nuclear)

PG&E forecasts nuclear property premium costs of \$110 thousand.³³⁶⁴ No party has contested this forecast and the Commission should adopt it without modification.

This program provides coverage for the cost of repair and replacement of first-party nuclear property from loss perils (such as floods, earthquakes and fires), decontamination and stabilization following a catastrophic nuclear event, and reimbursement for business interruption

³³⁶⁰ PG&E-09, WP 3-53 – Property Market Dynamics – Aon, Q1 2021 Update.

³³⁶¹ PG&E-09, p. 3-17, lines 5-8; p. 3-18 line 7 to p. 3-19, line 3.

³³⁶² PG&E-09 p. 3-17, line 9 to p. 3-18, line 6.

³³⁶³ PG&E-09 p. 3-17, line 9 to p. 3-18, line 6.

³³⁶⁴ PG&E-09, p. 3-19, lines 5-6.

expenses (replacement power costs) at a damaged facility in the event a plant is shut down. Given the risks specific to the nuclear energy industry, the insurance programs for Diablo Canyon Power and HBPP are separate from other PG&E insurance programs and generally excluded in non-nuclear insurance products.³³⁶⁵ PG&E will need to continue the purchase of nuclear property insurance for DCPD despite the planned retirement of that location in 2025 due in large part to the presence of nuclear fuel that will continue to be stored on the premises during the decommissioning process. The 2023 forecast includes the anticipated premium cost to continue the purchase of coverage for DCPD following the plant's retirement from service.³³⁶⁶

PG&E purchases nuclear property insurance from two industry mutuals: (1) Nuclear Electric Insurance Limited (NEIL); and (2) European Mutual Association for Nuclear Insurance (EMANI). NEIL was established in the early 1970s by nuclear power plant owners. PG&E's forecast accounts for anticipated future NEIL distributions in its forecast.³³⁶⁷ The forecast also accounts for an approved reduction to the amount of property insurance required to be carried at HBPP to \$50 million due to its current decommissioning status. The estimated premium cost savings from this program change is approximately \$66 thousand annually.³³⁶⁸

Cal Advocates, TURN and PG&E have stipulated that this forecast should be adopted as described in Table 9-1.

³³⁶⁵ PG&E-09, p. 3-19, lines 6-15.

³³⁶⁶ PG&E-09, p. 3-19, lines 15-22.

³³⁶⁷ PG&E-09, p. 3-50, Table 3-11, lines 4-5 (forecast distributions are based on NEIL's targeted annual distributions in 2022, which was the most current available at the time of the filing multiplied by a 2.5 percent factor, which represents the historical amount of NEIL distributions that have been allocated to PG&E).

³³⁶⁸ PG&E-09, p. 3-20, lines 8-16.

9.4.2.1.3 Property Insurance (Other)

PG&E forecasts \$2.6 million for Other Property insurance, which is approximately 20 percent more than 2020 recorded costs.³³⁶⁹ No party has contested this forecast and the Commission should adopt it without modification.

The primary cost driver in this program is the premium cost of insurance (referred to as “hull” insurance) for helicopters and specialty equipment attached to the Company’s airplane fleet for pipeline and powerline inspections (cameras, navigational and infrared asset scanning equipment) purchased by PG&E since its last GRC.³³⁷⁰ In its 2020 renewal, the utility paid an estimated total of \$1.04 million in property insurance costs attributed to these assets, more than ninety percent of which relates to property insurance on PG&E’s helicopters. This compares to an estimated spend of approximately \$31 thousand that PG&E paid for “hull” coverage in the renewal leading into the 2020 GRC period. These procurements have occurred in the midst of a tightening aviation insurance market due to industry losses arising from events such as the grounding of Boeing 737 Max passenger airlines between March 2019 to November 2020 (the policies may provide “layup” coverage which reimburses policyholders when aircraft is not in use over a certain time period), and an increase in the number of fatal aviation accidents in recent years.³³⁷¹

Cal Advocates, TURN and PG&E have stipulated that this forecast should be adopted as described in Table 9-1.

9.4.2.2 General Liability Insurance

9.4.2.2.1 Wildfire Liability Insurance

PG&E, Cal Advocates and TURN were the only parties to address PG&E’s wildfire liability insurance program and forecast. The parties have filed a settlement for Commission

³³⁶⁹ PG&E-09, p. 3-50, Table 3-11, line 7.

³³⁷⁰ PG&E-09, p. 3-20, line 20 to p. 3-21, line 18.

³³⁷¹ PG&E-09, WP 3-66 – General Aviation Insurance Overview – Marsh, Q1 2021.

approval and adoption that would resolve all issues with respect to wildfire liability insurance in this GRC. This section briefly summarizes PG&E’s forecast as filed, parties’ litigation positions and the resolution reached in the Insurance Settlement.

PG&E forecasted \$707 million for wildfire liability insurance in 2023.³³⁷² The forecast was based on the coverage PG&E had available from multi-year policies in 2020 and through 2021 recorded data, which was the most recent available at the time of the filing, as indicated in Table 9-3 below.³³⁷³

TABLE 9-3
2023 LIABILITY INSURANCE FORECAST SUMMARY
(MILLIONS OF NOMINAL DOLLARS)

Line No.		Multi-Year Coverage Remaining from 2020 Renewal	Additional Single-Year Coverage from 2021 Renewal	Total Coverage and Premium as of April 2021	2023 Forecast
1	Premium	\$501	\$207	\$707	\$707
2	Coverage	\$600	\$300	\$900	\$900

The forecast accounted for the fact that PG&E and the other California utilities have continued to see increases in the cost of wildfire liability insurance offered in the commercial marketplace.³³⁷⁴ The price of insurance is affected by a number of factors including, continued exposure to wildfire risk given our service area characteristics, California’s application of inverse condemnation law, and PG&E-specific considerations (e.g., percentage of service territory in elevated fire risk areas, percentage of PG&E electric lines in elevated risk areas),³³⁷⁵

³³⁷² PG&E-09, p. 3-26, lines 6-7.

³³⁷³ PG&E-09, p. 3-26, line 7 to p. 3-27, line 2 and Table 3-5.

³³⁷⁴ PG&E-09, p. 3-24, lines 16–28.

³³⁷⁵ The insurance markets perceive wildfire risk as primarily an electric operations exposure. The majority of wildfire ignitions for which insurance claims have ultimately been paid out in recent years were related to PG&E’s electrical facilities.

concentration of properties within these risk areas, the frequency and severity of claims). Additionally, the number of market participants and the total amount of coverage available in the market continues to decrease.³³⁷⁶

PG&E secured \$900 million of coverage as of April 2021.³³⁷⁷ In its Post Test-Year Ratemaking (PTYR) exhibit, PG&E also proposed an annual attrition adjustment of \$75 million for each year 2024 through 2026 as compared to the 2023 forecast.³³⁷⁸ The purpose of the attrition adjustment was to account for the cost of procuring an additional amount of insurance to meet our \$1 billion target, consistent with the AB 1054 structure that holds the IOUs responsible for the first \$1 billion in claim costs before the Wildfire Fund may be accessed.³³⁷⁹

PG&E made two self-insurance proposals to the Commission. PG&E recommended that \$250 million of the \$707 revenue requirement and the additional amounts during the attrition years be applied to self-insurance.³³⁸⁰ PG&E noted that self-insurance provides potential cost savings benefits that traditional commercial insurance does not.³³⁸¹ With commercial policies, the premium is paid whether the coverage is used or not. In contrast, to the extent self-insurance is not used in a given year it remains available for use in future years.³³⁸² Additionally, payments from a self-insurance fund would not be due until claims are ultimately settled, which

³³⁷⁶ PG&E-09, p. 3-24, lines 16–28.

³³⁷⁷ PG&E-09, p. 3-27, lines 11-14.

³³⁷⁸ The \$75 million attrition adjustment is based on the procurement of an additional \$100 million in wildfire insurance to fill the tower to \$1 billion, at a ROL of 75 percent as determined by market pricing recently experienced by PG&E.

³³⁷⁹ PG&E-09, p. 3-27, lines 18-22; Pub. Util. Code § 3280 (f).

³³⁸⁰ PG&E-09, p. 3-31, line 14 to p. 3-37, line 2.

³³⁸¹ PG&E-09, p. 3-29, lines 4-20.

³³⁸² PG&E-09, p. 3-29, lines 4-20.

can occur years after an event. In contrast, premiums for a commercial policy applicable to the same event need to be paid at the time the policy is bound.³³⁸³

Finally, PG&E requested authority to continue the RTBA for wildfire liability insurance noting the difficulty of accurately forecasting premium costs and the uncertainty around the amount of coverage that would ultimately be available to purchase in the commercial market.

Cal Advocates recommended \$353.8 million for wildfire liability insurance, opposed PG&E's proposed attrition adjustment,³³⁸⁴ and also recommended that the Commission discontinue PG&E's authority to track costs of wildfire insurance above its forecast in the RTBA.³³⁸⁵ Cal Advocates did not oppose PG&E's use of self-insurance but recommended that it should be shareholder-funded.³³⁸⁶

TURN made three recommendations: (1) PG&E should not purchase any commercial insurance and instead should rely solely on self-insurance for the 2023 GRC period;³³⁸⁷ (2) the forecast for self insurance should be capped at \$333 million;³³⁸⁸ (3) ratepayers should only fund half of the cost of PG&E's commercial insurance premiums and other amounts should be subject to reasonableness review.³³⁸⁹

On October 7, 2022, PG&E, TURN and Cal Advocates filed a motion for adoption of the Insurance Settlement that would resolve all issues with respect to PG&E's wildfire liability insurance program and forecast.³³⁹⁰ The settlement includes a 100% self-insurance framework

³³⁸³ PG&E-09, p. 3-29, lines 4-20.

³³⁸⁴ CALPA-13, p. 14, lines 5-8., p. 5 line 20 to p. 6, line 2.

³³⁸⁵ CALPA-13, p. 14, lines 19-22.

³³⁸⁶ CALPA-13, p. 9, lines 19-23, p. 13, lines 5-8; p. 14, lines 9-10.

³³⁸⁷ TURN-17, p. 1, lines 15-18; p. 16, lines 9-13; p. 21, lines 4-6.

³³⁸⁸ TURN-17, p. 1, lines 15-18; p. 17, lines 8-14.

³³⁸⁹ TURN-17, p. 9, lines 8-16 and p. 26, lines 6-14.

³³⁹⁰ Joint Motion for Adoption of Insurance Settlement.

for wildfire liability insurance that has the potential to save a significant amount of costs for customers compared to the cost of continuing to include commercial market insurance in PG&E's program.³³⁹¹ Among other things, the settlement provides: (1) an initial \$400 million revenue requirement for 2023, which is \$307 million less than PG&E forecasted for that year;³³⁹² (2) that none of the self-insurance funding shall be subject to additional reasonableness review or refund;³³⁹³ (3) a shareholder-funded deductible in the amount of 5 percent of up to \$1 billion in claims annually not to exceed \$50 million;³³⁹⁴ (3) adjustment of revenue requirements for future years based on estimated claims activity and the recovery of any potential undercollection if necessary over a number of years after the 2023 GRC period concludes;³³⁹⁵ (4) continuation of the RTBA with modifications necessary to implement the self-insurance framework described in the settlement;³³⁹⁶ and (5) a Tier 2 advice letter process to support report on and calculate revenue requirements and handle other issues over the course of the 2023 GRC period.³³⁹⁷

For the reasons described in the Joint Motion for Adoption of Insurance Settlement, the settlement is supported by the record, consistent with law, and in the public interest, and should be adopted by the Commission without modification.

³³⁹¹ Joint Motion for Adoption of Insurance Settlement, pp. 1-2.

³³⁹² Joint Motion for Adoption of Insurance Settlement, p. 9 (referencing Settlement Section 3.2.1).

³³⁹³ Joint Motion for Adoption of Insurance Settlement, p. 11 (referencing Settlement Section 3.4).

³³⁹⁴ Joint Motion for Adoption of Insurance Settlement, p. 9 (referencing Settlement Section 3.2.3).

³³⁹⁵ Joint Motion for Adoption of Insurance Settlement, p. 10 (referencing Settlement Sections 3.2.2.1, 3.2.2.2, and 3.3).

³³⁹⁶ Joint Motion for Adoption of Insurance Settlement, p. 11 (referencing Settlement Section 3.8).

³³⁹⁷ Joint Motion for Adoption of Insurance Settlement, p. 11 (referencing Settlement Section 3.7).

9.4.2.2.2 Non-Wildfire Liability Insurance

PG&E forecasts \$156 million for non-wildfire liability insurance for 2023. The forecast is based on PG&E's recorded cost of \$148 million, which has been escalated by factor of 2 percent annually and assumes the same \$700 million coverage target.³³⁹⁸

Cal Advocates, TURN and PG&E have stipulated that this forecast should be adopted as described in Table 9-1.

9.4.2.3 Directors And Officers Liability Insurance

PG&E forecasts \$17.6 million for its 2023 D&O Liability Program, which is a 9 percent increase compared to 2020 premium costs of approximately \$16.2 million.³³⁹⁹ In accordance with prior Commission guidance, PG&E seeks recovery of \$8.8 million, which is 50 percent of the total forecast cost for D&O insurance for 2023.³⁴⁰⁰ No party has contested this forecast and the Commission should adopt it without modification.

PG&E requires this insurance to attract qualified Directors, Officers, and trustees who would otherwise be unlikely to accept these positions without such coverage because of the litigation risk.³⁴⁰¹ For that reason, the cost of D&O insurance is a reasonable cost of providing utility service. The premium cost increase is due in large part to a hardening of the D&O liability insurance market as a result of Increased claim frequency from "event-driven" class-action lawsuits;³⁴⁰² increased claim frequency from recent court decisions permitting claimants to pursue recoveries in multiple legal venues; growth in the number of plaintiff firms

³³⁹⁸ PG&E-09, p. 2-31, line 24 and p. 3-23 line 25 to p. 3-24, line 6.

³³⁹⁹ PG&E-09, p. 3-45, lines 2-4.

³⁴⁰⁰ See D.14-08-032, p. 713, FOF 262. Note, the PG&E Utility portion of that is \$6.4 million. The PG&E Corporation portion of these costs is approximately \$2.3 million and is included within the total "PG&E Corporate Allocation."

³⁴⁰¹ PG&E-09, p. 3-45, lines 5-8.

³⁴⁰² Event-driven lawsuits refers to litigation following negative press from an event, activity or response to social trends (e.g., COVID-19 response, Board Diversity, cyber-attack #MeToo, etc.). This differs from traditional Directors and Officers claims which focuses on accounting practices, merger and acquisition decisions, and securities fraud allegations.

bringing suits against publicly traded companies; global insurance market losses attributed to opioid litigation in the United States; and an increase in the number of insurers exiting the market.³⁴⁰³

Cal Advocates, TURN and PG&E have stipulated that this forecast should be adopted as described in Table 9-1.

9.4.2.4 Other Liability Insurance

PG&E forecasts \$6.2 million for Other Liability insurance, which is approximately 7 percent less than 2020 recorded costs.³⁴⁰⁴ The forecast accounts for increased costs related to our surety bond program, used as a form of guarantee when work is performed for others under a contract or permit, and fiduciary liability insurance premiums intended to cover liabilities associated with the management of employee benefit plans, including employer provided retirement programs.³⁴⁰⁵

Cal Advocates, TURN and PG&E have stipulated that this forecast should be adopted as described in Table 9-1.

9.4.2.5 PG&E Corporation Allocation

PG&E Corporation forecasts \$2.7 million in costs for 2023.³⁴⁰⁶ This forecast represents the Corporation's allocation of costs for coverage provided under many of the same policies identified in the property and liability discussions above.³⁴⁰⁷ PG&E Corporation is also insured under those programs. Because nearly all of the Corporation's work is for the benefit of the

³⁴⁰³ PG&E-09, p. 3-45, lines 10-25.

³⁴⁰⁴ PG&E-09, p. 3-50, Table 3-11, line 12. Please note, PG&E incurred higher one-time fiduciary liability costs in 2020 due to the Company's bankruptcy (separate coverage needed to be purchased covering potential liabilities for both the pre-emerged company, and the new company upon bankruptcy exit).

³⁴⁰⁵ PG&E-09, p. 3-43, line 29 to p. 3-44, line 28.

³⁴⁰⁶ PG&E-09, p. 3-50, Table 3-11, line 18.

³⁴⁰⁷ PG&E-09, p. 3-46, lines 19-28.

Utility, PG&E's forecast appropriately includes the Corporation's share of insurance costs. The decrease in cost compared to 2020 recorded adjusted is primarily due to the allocation of one-time Directors and Officers Liability costs incurred by PG&E in relation to its bankruptcy proceeding that are not expected to recur in 2023.³⁴⁰⁸

Cal Advocates, TURN and PG&E have stipulated that this forecast should be adopted as described in Table 9-1.

9.4.2.6 Risk Transfer Balancing Account

9.4.2.6.1 Summary Of Parties' Litigation Positions

In the 2020 GRC, the Commission authorized creation of the two-way RTBA to manage the uncertain costs associated with General Liability insurance that were not easily forecast. In doing so, the Commission stated:

Regarding the establishment of the RTBA, we agree that insurance costs for General Liability coverage has been difficult to predict in recent times because of market conditions and the recent wildfires in California. A two-way balancing account will also allow PG&E to address uncertainty in a timely manner and at the same time ensure that there is adequate insurance coverage.³⁴⁰⁹

The current RTBA terms are as follows:

PG&E shall establish a two-way RTBA to recover the costs of PG&E's excess liability insurance coverage exceeding its adopted forecast for coverage of up to \$1.4 billion. PG&E may file a Tier 2 advice letter for coverage beyond \$1.4 billion, consistent with Cal Advocates' proposal.³⁴¹⁰

PG&E requested authority to continue the RTBA with modifications for the 2023 GRC period for its wildfire and non-wildfire liability programs, to manage the proposed insurance

³⁴⁰⁸ PG&E-09, p. 3-46, lines 19-28.

³⁴⁰⁹ D.20-12-005, p. 254, p. 403, COL, 83.

³⁴¹⁰ A.18-12-009, Joint Motion of the Public Advocates Office, The Utility Reform Network, Small Business Utility Advocates, Center for Accessible Technology, The National Diversity Coalition, Coalition of California Utility Employees, California City County Street Light Association, The Office of The Safety Advocate and Pacific Gas and Electric Company for Approval of Settlement Agreement (Dec. 20, 2019) (Settlement Agreement), p. 28, Section 2.8.3.2.

attrition adjustment, and for excise taxes. A summary of PG&E’s RTBA proposal as filed in its application and as would result from the Insurance Settlement is shown in Table 9-4 below.

TABLE 9-4
SUMMARY OF INSURANCE COSTS SUBJECT TO RTBA
(MILLIONS OF NOMINAL DOLLARS)

Line No.		Amount – As Filed in A. 21-06-021	Amount – PG&E, TURN, Cal Advocates Settlement on Wildfire Insurance	Cost Recovery	Reference
1	2023 Forecast: Wildfire Liability	\$707 total (\$250 self-insurance; \$457 other wildfire coverage if PG&E’s self-insurance proposal is adopted.)	\$400 million in 2023 for self-insurance only. Amount for 2024-2026 determined by adjustment mechanism and other settlement terms.	Up to \$1 billion in coverage through the RTBA; Coverage over \$1 billion through Tier 2 Advice Letter	Ex. 9, Ch. 3, Section C.3.b.1.b
2	2023 Forecast: Non-Wildfire Liability	\$156	Not addressed in wildfire insurance settlement agreement.	Up to \$700 million in coverage through the RTBA; Coverage over \$700 million through Tier 2 Advice Letter	Ex. 9, Ch. 3, Section C.3.b.1.c
3	2024-2026 PTY Attrition Proposal on Insurance	\$75	\$0	Through the RTBA	Ex. 11, Ch.2, Section C.3.b.1.c.i
4	Excise Tax	\$33.4	2023 – At least a \$14 million reduction. 2024-2026 – Reductions to the extent there are excise tax cost savings from the self-insurance only structure.	Through RTBA and Tier 2 AL as noted above for the underlying coverage type and amount	Ex. 10, Ch. 9

TURN recommended a substantially restructured RTBA such that all costs tracked to the account should be subject to reasonableness review in an application-based proceeding.³⁴¹¹ Cal Advocates recommended that the Commission should not authorize the continued use of the RTBA for PG&E’s wildfire liability insurance program.³⁴¹²

³⁴¹¹ TURN-17, p. 9, lines 7-9.

³⁴¹² CALPA-13, p. 14, lines 19-22.

9.4.2.6.2 Summary Of Settlement And Stipulations For The RTBA

As described in Section 9.4.2.2.1 above, PG&E, Cal Advocates and TURN reached a settlement on wildfire liability insurance, which, if adopted, would resolve PG&E's request for authority to continue the RTBA for its wildfire liability insurance program. Specifically, the Insurance Settlement provides for the continuation of the RTBA for wildfire insurance as required to support the implementation of the 100 percent self-insurance framework.³⁴¹³ The settlement also makes clear that there will be no attrition adjustment for wildfire liability insurance as PG&E initially proposed.³⁴¹⁴

As described in Table 9-1 above, PG&E, TURN and Cal Advocates have stipulated to the RTBA's application to non-wildfire liability insurance. For non-wildfire liability insurance, PG&E will track in the RTBA costs incurred to procure coverage up to the \$700 million coverage target. If annual incurred costs are less than PG&E's forecast of \$156 million, PG&E will return to ratepayers in the next annual RTBA true-up the difference between the amount collected and amount incurred. If annual incurred costs are above the forecast amount, PG&E is permitted to seek recovery of such costs by application.

9.4.3 Information Technology

PG&E forecasts \$0.1 million in expense for 2023, and capital costs of \$1 million in 2022 and \$0.5 million annually from 2023-2026.³⁴¹⁵ No parties have addressed these programs or contested the expense forecast. Parties' recommend using PG&E's 2021 recorded capital expenditures for its 2021 forecast. See Appendix B.

The focus of the work for 2023 and beyond is to upgrade IT applications that M&CRM uses for its control, reporting, risk-management functions. One application PG&E will update is the Procurement Portfolio Planner (PPP). The PPP is a Monte Carlo simulation model

³⁴¹³ Joint Motion for Adoption of Insurance Settlement, p. 11 (referencing Settlement Section 3.8).

³⁴¹⁴ Joint Motion for Adoption of Insurance Settlement, p. 4, Section 3.2.2.4.

³⁴¹⁵ PG&E-09, WP 3-33 to WP 3-37.

developed in house to provide an accurate representation of the bundled electric portfolio at the Utility, to forecast generation and procurement costs for the Utility's portfolio, to provide probabilistic distributions of volumes and costs, and to conduct analysis to support the procurement business. PPP forecasts net open portfolio positions and calculates risk metrics and mark to market for regulatory and financial compliance reporting, such as TeVaR.³⁴¹⁶ PG&E also plans to update other critical applications as necessary developed and managed by M&CRM which may include those for measuring Liquidity at Risk, Potential Future Exposure and Loss Given Default credit calculations, hedge compliance for the Bundled Electric portfolio, and the Core Procurement Incentive Mechanism model for Core Gas Supply.³⁴¹⁷

9.5 Compliance And Ethics

The Compliance and Ethics (C&E) Department is responsible for enhancing and promoting an effective C&E program that is designed to prevent and detect criminal conduct, and promote an organizational culture that encourages ethical conduct and a commitment to compliance with applicable laws and regulations.³⁴¹⁸ The C&E program is modeled after the United States (U.S.) sentencing guidelines requirements for an effective C&E program.³⁴¹⁹

PG&E is a large and complex organization and has designed its C&E program to engage each level of the organization—from the LOBs to the corporate board—while enhancing coordination across LOBs. Specifically, PG&E has implemented a C&E program that: (1) is accountable to the Boards of Directors; (2) is supported by senior-level commitment; (3) has visibility within each LOB; (4) manages, reports and collaborates on compliance efforts across

³⁴¹⁶ PG&E-09, WP 3-33 to WP 3-37.

³⁴¹⁷ PG&E-09, WP 3-33 to WP 3-37; PG&E-09, WP 3-38.

³⁴¹⁸ PG&E-09, p. 4-1, lines 6-24.

³⁴¹⁹ PG&E-09, p. 4-1, lines 6-24. The United States Sentencing Commission's sentencing guidelines were formally adopted in 1987. The guidelines provide a model of good corporate citizenship and apply to corporations, partnerships, labor unions, pension funds, trusts, non-profit entities, and governmental units.

LOBs; (5) communicates these values throughout the organization and provides thoughtful training and feedback mechanisms; (6) promotes a culture where all employees are encouraged to “speak up”; (7) identifies gaps, measures results, and fosters continuous improvement throughout the Company; and (8) promotes accountability.³⁴²⁰

9.5.1 Department Costs

The C&E organization is a part of the General Counsel department which is headed by the Executive Vice President (EVP), General Counsel and Chief Ethics and Compliance Officer (CECO). The CECO reports directly to the CEO of PG&E Corporation.³⁴²¹

PG&E’s TY 2023 expense forecast for department costs as reflected in rebuttal testimony is \$8.3 million.³⁴²² This is a \$1.1 million (14.6 percent) increase compared to 2020 recorded adjusted costs³⁴²³ and is primarily attributable to labor escalation, filling existing positions that were vacant in the organization in 2020, and a small reduction in contracts.³⁴²⁴ No parties have contested the department cost forecast and the Commission should adopt it without modification.

9.5.2 Technology Projects

PG&E forecasts \$0.2 million in expense and \$0.5 million capital per year from 2022-2026 to upgrade existing IT systems that support Compliance & Ethics.³⁴²⁵ The organization will update MetricStream, PG&E’s Compliance Management Tool which provides comprehensive and uniform risk and compliance management capabilities and is used across the enterprise.³⁴²⁶ The updates will increase the reach and efficiency of MetricStream, supporting

³⁴²⁰ PG&E-09, p. 4-1, lines 6-24.

³⁴²¹ Additional information about Compliance and Ethics’ activities can be found throughout PG&E-09, Ch. 4.

³⁴²² PG&E-22, p. 1-3, Table 1-1, line 3.

³⁴²³ PG&E-09, p. 4-2, lines 1-4.

³⁴²⁴ PG&E-09, p. 4-8, lines 3-25.

³⁴²⁵ PG&E-09, p. 4-8, lines 27-29.

³⁴²⁶ PG&E-09, p. 4-8, line 29 to p. 4-9, line 7; WP 4-33 to WP 4-34.

the goal of continually improving compliance performance. PG&E also plans to implement an update to enable mobile access to guidance documents. The project will increase access to these key resources for PG&E field- and office-based employees and contractors who leverage mobile devices as their primary technology tools. The guidance document update will be completed prior to 2023.³⁴²⁷

No parties have addressed these programs or contested the expense forecast. Parties recommend using PG&E's 2021 recorded capital expenditures for its 2021 forecast. See Appendix B.

9.6 Regulatory Affairs

The Regulatory Affairs organization provides to the operating LOBs expertise in state and federal regulatory matters. This includes regulatory policy development and implementation, advocacy, rate design and data analysis, and the management of a growing number of complex regulatory cases and initiatives. Since PG&E is a regulated company, the functions performed by the Regulatory Affairs organization are necessary for PG&E to serve its customers.³⁴²⁸

9.6.1 Department Costs

PG&E's TY 2023 expense forecast for department costs as reflected in rebuttal testimony is \$17.3 million³⁴²⁹ and is uncontested. The 2023 forecast is approximately \$1.4 million (8.9 percent) higher than the 2020 recorded amount of \$15.9 million. The \$1.4 million increase is primarily attributable to labor escalation and costs to backfill vacant positions.³⁴³⁰ No parties

³⁴²⁷ PG&E-09, p. 4-9, lines 3-7; WP 4-35.

³⁴²⁸ PG&E-09, p. 5-1, lines 6-13.

³⁴²⁹ PG&E-22, p. 1-3, Table 1-1, line 4. Additional information about the Regulatory Affairs Organization activities can be found throughout PG&E-09, Ch. 5.

³⁴³⁰ PG&E-09, p. 5-2, lines 1-4; p. 5-10, lines 9-22 and WP 5-31, line 29.

have addressed or contested this forecast and the Commission should adopt it without modification.

9.6.2 Technology Projects

PG&E forecasts a total of \$0.4 million in expense for 2023, and \$1.5 million in capital for each year from 2022 to 2026 for two technology projects to enhance its analytical capabilities: (1) Cost of Service Enhancements; and (2) Gas Rate Design Enhancements. These projects support the Safety, Governance, Regulatory, and Compliance value stream as described in Exhibit (PG&E-7), Chapter 8. PG&E forecasts \$100 thousand in capital in 2021 for model validation and stabilization of the Model Platform and Data Integration project which was approved in the 2020 GRC. No party has addressed these projects. Parties recommend using PG&E's 2021 recorded capital expenditures for its 2021 forecast. See Appendix B.

The purpose of the Cost of Service Enhancements project is to make cost data from PG&E's SAP financial system available to PG&E's analytics platform to enable the development of new Cost of Service models that can be used to improve downstream Revenue Allocation and Rate Design models.³⁴³¹ The Gas Rate Design Project will enable integration of customer specific information concerning usage levels and patterns, income levels, and information regarding the type of premise (single family home, multi-family, North American Industry Classification System code for small commercial customers, etc.) with information concerning the risk-based timeline of when that gas line, services, regulators, and meters could require normal replacement. Analyzing the distribution of these joint characteristics will inform PG&E's ability to propose targeted rate designs and programs to more efficiently achieve electrification of customers served from PG&E's gas distribution system. This is compared to a

³⁴³¹ PG&E-09, p. 5-12, lines 2-5 and WP, 5-52 to WP 5-54.

status quo scenario of random electrification where PG&E must maintain the current gas distribution system in service as total gas demand declines.³⁴³²

9.7 Law Department

The Law Department provides legal services and reports to PG&E's EVP and General Counsel. The Law Department and General Counsel's immediate office are collectively referred to in this chapter as the Law Organization. The Law Organization represents the Company in all its regulatory and legal matters and provides advice and counsel to support the safe and reliable operation of PG&E's business.³⁴³³

9.7.1 Department Costs

PG&E's TY 2023 expense forecast for department costs as reflected in rebuttal testimony is \$46.7 million³⁴³⁴ and is uncontested. Department costs include labor, materials, and outside contracts. The 2023 forecast of \$46.7 million is approximately \$2.5 million (5 percent) lower than the 2020 recorded adjusted amount of \$49.1 million and reflects a forecast reduction of 3 Full-Time Equivalent employees by 2023.³⁴³⁵ PG&E expects to manage these costs at a level below normal escalation by replacing staff who leave the department through natural attrition with lower cost resources and reducing outside services costs.

9.7.2 Companywide Expense (Settlements, Judgements And Claims)

The Law Department records two types of costs in Account 925: (1) settlement and judgment costs as part of its litigation function; and (2) claims payments to third-parties that did not proceed to litigation, alleging personal injury, property damage, and economic loss as a result of PG&E's operations. PG&E maintains a self-administered, self-insured claims management

³⁴³² PG&E-09, p. 5-12, lines 9-21 and WP 5-55 to WP 5-58.

³⁴³³ PG&E-09, p. 6-1, lines 6-13. Additional information about Law Organization activities can be found throughout PG&E-09, Ch. 6.

³⁴³⁴ PG&E-22, p. 6-3, Table 6-1, line 3.

³⁴³⁵ PG&E-09, p. 6-12, Table 6-1, line 3; p. 6-7, lines 15-23.

program covering settlement of single incident claims up to \$10 million. Starting in 2020 wildfire related events will be self-insured for claims up to \$60 million. Catastrophic coverage for certain single incident claims is typically provided by the Associated Electric and Gas Insurance Services and other insurers.³⁴³⁶

PG&E's TY 2023 forecast for companywide expenses as reflected in rebuttal testimony is \$36.4 million.³⁴³⁷ The forecast includes: (1) \$20.3 million for Settlements and Judgments; and (2) \$16.0 million for Third-Party Claims payments. Both forecasts are based on the average of the recorded adjusted payments for the 3-year period 2017, 2018, and 2020.³⁴³⁸ PG&E excluded 2019 from the average because most litigation against the company was stayed in that year due to the bankruptcy proceeding.³⁴³⁹

Cal Advocates recommends \$17.1 million for Settlements and Judgments, which is a \$3.2 million reduction to PG&E's forecast³⁴⁴⁰, for a total Settlements, Judgments and Third-Party Claims forecast of \$31.44 million. The basis of Cal Advocates' proposed reduction is: (1) that PG&E's 2020 recorded costs for Settlements and Judgments should be reduced by \$38.8 million; and (2) that for its 2023 Settlements and Judgments forecast, PG&E should use a 4-year average of recorded costs (2017-2020) as opposed to the three year average (2017, 2018, 2020) that PG&E used.³⁴⁴¹

³⁴³⁶ PG&E-09, p. 6-8, line 24 to p. 6-9, line 2.

³⁴³⁷ PG&E-22, p. 6-3, Table 6-2, line 3.

³⁴³⁸ PG&E-22, p. 6-5, lines 13-21.

³⁴³⁹ PG&E-22, p. 6-5, lines 13-21.

³⁴⁴⁰ Cal Advocates states that its proposed reduction is \$7.9 million less than PG&E's forecast of \$25.059 million. (CALPA-13, p. 2, lines 23-25 and p. 3, Table 13-1, row G.) That is incorrect. The \$25.059 million forecast Cal Advocates references was included in PG&E's opening testimony dated June 30, 2021. PG&E has since revised the forecast to \$20.343 million in its February 28, 2022 errata filing (PG&E-09 (Feb. 28, 2022), p. 6-1, lines 25-26; p. 6-8 to p. 6-10; and p. 6-13, Table 6-3, line 1.) The difference between the updated forecast and Cal Advocates recommendation is \$3.2 million.

³⁴⁴¹ CALPA-13, p. 16, lines 1-15.

As described in Table 9-1, PG&E and Cal Advocates have stipulated to a forecast of \$33.9 million, which represents the midpoint between the parties' respective litigation positions.

9.7.3 Technology Projects

PG&E's TY 2023 expense forecast for information technology is \$0.314 million and is uncontested.³⁴⁴² The Law Department is planning the following technology investments to help improve and modernize PG&E's third-party claims system.³⁴⁴³

PG&E's Third party claims system is planned to migrate from outdated unsupported servers to a cloud solution in 2021. To avoid risk of losing the repository of evidence supporting Litigation and all privileged investigations conducted by the Claims department involving third-party injury/fatality, property damage or business loss, a migration is necessary.³⁴⁴⁴

Other investments include revamping the Claims public webpage with mobile device integration. The project will require a phased approach to modernize and improve functionality of the site and build the capability for the public to submit claims through their mobile device. This effort is designed to improve the user experience for the customer through an improved interface and convenience of submitting a claim through their mobile device.³⁴⁴⁵

9.8 PG&E Corporation, PG&E Executive Offices And Corporate Secretary

PG&E Corporation CEO Patti Poppe is responsible for the executive leadership of PG&E and PG&E Corporation. Since PG&E is the sole operating subsidiary of PG&E Corporation, the activities of the Corporation CEO focus on the core business of PG&E.

The Enterprise PMO manages strategic enterprise-wide projects such as the Enhanced Oversight and Enforcement Process (EOEP), Major Commitments, and Enterprise Strategy for

³⁴⁴² PG&E-22, p. 6-4, Table 6-3, line 2.

³⁴⁴³ PG&E-09, p. 6-11, lines 3-17.

³⁴⁴⁴ PG&E-09, p. 6-11, lines 3-17.

³⁴⁴⁵ PG&E-09, p. 6-11, lines 3-17.

Data Responses. It also handles other special projects assigned to it by the Chief Operating Officer (COO) and Chief Risk Officer (CRO).

PG&E's Corporate Secretary Department supports the BOD of PG&E and PG&E Corporation and their respective committees; provides governance, reporting, shareholder, and other necessary services for PG&E and PG&E Corporation; and manages Director fees and expenses for the PG&E and PG&E Corporation BOD.³⁴⁴⁶

9.8.1 Department Costs

PG&E's TY 2023 expense forecast for department costs as reflected in rebuttal testimony is \$5.1 million³⁴⁴⁷ and is uncontested. Department costs include labor, materials, and outside contracts for the Corporation CEO's immediate office, the Enterprise PMO, and the Corporate Secretary Department.³⁴⁴⁸ The 2023 forecast is \$6.1 million (approximately 54.9 percent) lower than the 2020 recorded adjusted amount of \$11.2 million. The decrease is primarily due to reductions in costs for the Corporation CEO's immediate office and Enterprise PMO, offset by an increase in costs for the Corporate Secretary Department related to the proxy statement and annual meeting.³⁴⁴⁹

9.8.2 Companywide Expenses (Director Fees And Expenses)

The PG&E Corporation BOD currently consists of fifteen Directors. The PG&E BOD currently consists of sixteen Directors—the same fifteen Directors that serve on the PG&E

³⁴⁴⁶ PG&E-09, p. 7-2, lines 7-25. Additional information about PG&E Corporation and PG&E Executive Offices; and Corporate Secretary Department activities can be found throughout PG&E-09, Ch. 7.

³⁴⁴⁷ PG&E-22, p. 7-3, Table 7-1, line 4.

³⁴⁴⁸ Pursuant to CPUC Resolution E-4963 (Issued December 14, 2018), PG&E has excluded from its 2023 forecast the salary and benefits of the utility's SEC Rule 240.3b-7 officers. PG&E has also voluntarily excluded from its 2023 forecast to the salary and benefits of the PG&E Corporation's Securities and Exchange Commission (SEC) Rule 240.3b-7 officers although not required by the Resolution. See PG&E-08, Ch. 4 for further discussion of officer compensation costs.

³⁴⁴⁹ PG&E-09, p. 7-3, lines 8-16; p. 7-8, line 8 to p. 7-9, line 6.

Corporation Board and PG&E's Executive VP, Operations and COO. Of PG&E's sixteen Directors, fourteen are outside (i.e., non-employee) Directors, one is an Officer of PG&E Corporation (the Corporation CEO), and one is an Officer of PG&E (COO).

PG&E's TY 2023 forecast for companywide expenses as reflected in rebuttal testimony is \$2.4 million.³⁴⁵⁰ This is an increase of approximately \$769,000 (46 percent) compared to the 2020 recorded amount, which is due to a reduction of in person meetings due to COVID-19 in years 2020 and 2021 and escalation.³⁴⁵¹ These costs generally include retainer fees paid to directors and other reimbursable expenses related to attendance at, or participation in, Board, Board committee, or shareholder meetings, as well as other PG&E or PG&E Corporation activities including Director transportation (air and ground), lodging, Director education, and one PG&E facility tour per year.³⁴⁵² TURN recommends a forecast of \$1.2 million.³⁴⁵³

As described in Table 9-1 above, TURN and PG&E stipulate to a reduction of \$0.61 million for a total forecast of \$1.83 million.

9.9 Corporate Affairs Costs

Corporate Affairs department (Corporate Affairs) is responsible for communicating with community leaders and public officials at all levels of government.³⁴⁵⁴ Corporate Affairs provides critical information during emergencies, communicates public safety information, and keeps community stakeholders and government officials apprised of key changes to PG&E's operations in their local communities, including those relating to public safety and service options. Corporate Affairs is also responsible for building and maintaining successful working relationships with government officials and community stakeholders, advising on key matters

³⁴⁵⁰ PG&E-22, p. 7-3, Table 7-2, line 2.

³⁴⁵¹ PG&E-09, p. 7-10, lines 10-13; WP 7-38, line 6.

³⁴⁵² PG&E-09, p. 7-10, line 14 to p. 7-11, line 6.

³⁴⁵³ TURN-05, p. 16.

³⁴⁵⁴ PG&E-09, p. 8-1, lines 6-21.

related to the delivery of safe, reliable, affordable, and clean gas and electric service. Corporate Affairs works to develop strategies to align and adapt the Utility with current and future changes in policy and customer preferences to minimize costs while delivering products and services that meet customers' needs and prioritize the focus on safety.³⁴⁵⁵

PG&E's TY 2023 expense forecast for department costs as reflected in rebuttal testimony is \$8.9 million³⁴⁵⁶ and is uncontested. The 2023 forecast is \$1.9 million (26.7 percent) higher than the 2020 recorded adjusted amount of \$7.0 million.³⁴⁵⁷ The \$1.9 million increase is primarily attributable to the following drivers: (1) labor escalation; (2) staffing costs to support the Climate Vulnerability Assessment (CVA) beginning in 2023, as well as the Local Government Relations function; and (3) Contract support for the CVA program.³⁴⁵⁸

9.10 Administrative And General Ratemaking Adjustments

PG&E adjusts A&G expenses to determine the appropriate amount to be included in the GRC and to present those costs in the format required by the Commission. Specifically, PG&E removes certain items from its A&G expense forecast, which are not recoverable in customer rates.³⁴⁵⁹ For example, PG&E removes below the line (BTL) activities and a portion for non-Utility affiliate activities. The removal of these items reduces the overall revenue requirement forecast. PG&E also capitalizes certain A&G costs. The purpose of the capitalization adjustment is to properly account for expenses associated with construction projects included in capital

³⁴⁵⁵ PG&E-09, p. 8-1, lines 6-21. Additional information about Corporate Affairs activities can be found throughout PG&E-09, Ch. 8.

³⁴⁵⁶ PG&E-22, p. 1-3, Table 1-1, line 7.

³⁴⁵⁷ PG&E-09, p. 8-1, line 26-27; WP 8-3, line 5.

³⁴⁵⁸ PG&E-09, p. 8-1, line 27 to p. 8-2, line 3; p. 8-6, line 25 to p. 8-8, line 17.

³⁴⁵⁹ PG&E-09, p. 9-1, lines 5-12.

expenditure forecasts. These capitalized A&G costs will be recovered along with other capital costs over the life of each asset.³⁴⁶⁰

No parties made recommendations with respect to the A&G ratemaking adjustments described above.

³⁴⁶⁰ PG&E-09, p. 9-1, lines 17-26.

10. RESULTS OF OPERATIONS (EXHIBIT PG&E-10)

Exhibit 10 of PG&E's testimony presents PG&E's forecast of the revenue requirement for its electric distribution, gas distribution, electric generation, gas transmission and storage (GT&S) functions also summarizes PG&E's proposed revenue requirement to recover the costs of providing these services to PG&E's customers. This section of the Opening Brief is focused on the issues in Exhibit 10 addressed by other parties.

10.1 Depreciation

Pursuant to ALJ *DeAngelis' E-Mail Ruling Granting Extension of Time for Depreciation Section of Briefs*, dated November 1, 2022, this section of the Opening Brief will be submitted on November 10, 2022.

10.2 Income And Property Taxes

As discussed below, PG&E requests that the Commission adopt its 2023 forecast for income tax expense and property tax expense as presented in Opening Testimony³⁴⁶¹ and approve additional income tax items submitted in the September 6, 2022 Update Testimony.³⁴⁶² PG&E also requests that the Commission continue the Tax Memorandum Account (TMA) without revision.

10.2.1 PG&E's Opening Testimony

As described in PG&E's Opening Testimony, PG&E's calculation of its tax expense is informed by: (1) expenditure estimates provided by other witnesses; (2) past Commission decisions on how to perform the calculation; and (3) current tax laws.³⁴⁶³

PG&E summarized its forecast methodology in Opening Testimony and indicated that it: (a) accurately reflected the tax laws in its calculation of tax expense; (b) used Commission-mandated accounting and ratemaking methods; (c) calculated Federal Income Tax (FIT) and

³⁴⁶¹ PG&E-10, Chapter 13.

³⁴⁶² PG&E-33, p. 4-AtchA-3 and p. 4-AtchA-4.

³⁴⁶³ PG&E-10, p. 13-1, lines 26-29.

California Corporation Franchise Tax (CCFT) taxable income using appropriate deductions and adjustments equivalent to or forecasted from amounts filed in its federal and state tax returns and/or financial statements; and (d) based its property tax estimate on historical property tax rates and methods applied to the estimated net plant in service for this proceeding.³⁴⁶⁴ Cal Advocates in its June 13, 2022 testimony did not oppose the method by which PG&E calculated income, payroll and other taxes, and property taxes for Test Year 2023.³⁴⁶⁵ PG&E did not provide rebuttal testimony on income or property taxes because no party disputed PG&E’s showing in its opening testimony.

PG&E proposes to continue the Tax Memorandum Account as part of the 2023 GRC without revision.³⁴⁶⁶ Cal Advocates did not propose any changes to this account.³⁴⁶⁷

10.2.2 Update Testimony – Tax Updates (PG&E-33, Chapter 3)

The Rate Case Plan allows the utilities to update their opening testimony for certain enumerated changes including “known changes due to governmental action such as changes in tax rates”³⁴⁶⁸ Due to changes in tax law and future government guidance and/or action, PG&E served testimony updating its income taxes³⁴⁶⁹ on September 6, 2022 (Update Testimony). PG&E revised its proposed revenue requirements for the three following Tax items in the Update testimony: (1) Adjustments to Comply with the Internal Revenue Code (IRC) Normalization Rules; (2) Corporate Minimum Tax in the Inflation Reduction Act (IRA) of 2022; and (3) Gas Transmission (GT) Accounting Method Change pursuant to automatic change rules

³⁴⁶⁴ PG&E-10, p. 13-2, lines 2-12.

³⁴⁶⁵ CALPA-14, p. 3, lines 1-7.

³⁴⁶⁶ PG&E-10, p. 13-3, lines 20-21.

³⁴⁶⁷ CALPA-14, p. 3, lines 1-7.

³⁴⁶⁸ D.07-07-004, Appendix A, p. A-36, par. 1.C; see also D.21-08-036, p. 180.

³⁴⁶⁹ None of the three Tax items impacted property, payroll, or other taxes.

under Revenue Procedure 2022-14.³⁴⁷⁰ These changes impacted proposed rates in 2023, as well as in the attrition years.

10.2.2.1 Adjustments to Comply with the Internal Revenue Code Normalization Rules

As discussed in PG&E's Update Testimony, subsequent to the 2023 GRC filing on June 30, 2021, PG&E received an Internal Revenue Service (IRS) private letter ruling (PLR) 202211004, which addressed the appropriate treatment of cost of removal (COR) with respect to the amortization of Excess Deferred Income Taxes (EDIT) arising from the 2017 Tax Cuts and Jobs Act corporate tax rate reduction.³⁴⁷¹ In PLR 202211004, the IRS ruled that the CPUC's approach of including COR in the computation for the return of EDIT (referred to as the CPUC Method) violated the IRC normalization rules. PG&E must comply with the PLR to avoid a normalization violation.

PG&E filed Advice Letter (AL) 4579-G/6013-E to adjust rates to unwind the impermissible treatment of COR (under the CPUC Method) for pre-2023 periods. AL 4579-G/6013-E was approved on March 26, 2022. PG&E now unwinds the CPUC Method for 2023 and beyond through the Update Testimony. As mentioned above, this change is required by the IRS PLR to avoid a normalization violation. To reflect the PLR for the 2023 GRC period,³⁴⁷² PG&E updated line 48 of the RO Income Tax page "Amortization of DFIT" and the associated rate base impact through Accumulated Fixed Assets.³⁴⁷³

³⁴⁷⁰ PG&E-33, Ch. 3, Tax Updates.

³⁴⁷¹ PG&E-33, Ch. 3, p. 3-A-15 to p. 3-A-30 (Private Letter Ruling-113635-21 (Dec. 21, 2021)).

³⁴⁷² AL 4579-G/6513-E, filed February 24, 2022 and approved March 26, 2022, reflected this PLR for pre-2023 periods.

³⁴⁷³ PG&E-33, p. 4-4, line 28 to p. 4-5, line 1.

10.2.2.2 Inflation Reduction Act of 2022 – Corporate Alternative Minimum Tax

On August 16, 2022, the Inflation Reduction Act of 2022 (IRA) was enacted. The IRA includes a new CMT on Adjusted Financial Statement Income (AFSI) of 15 percent. The CMT applies to taxpayers that generate AFSI of over \$1 billion, tested over a three-year average and computed with specific adjustments.³⁴⁷⁴ Such taxpayer is required to pay the greater of its “regular” tax (computed under conventional tax rules) or the CMT in tax years beginning in 2023.

The CMT constitutes a tax law change. The majority of the elements needed for the CMT calculation are within the RO Model. Therefore, the calculation of CMT was included in the mechanics of the RO Model³⁴⁷⁵ applying PG&E’s current understanding of the IRA.

Similar to other major tax legislation, the IRS and Treasury are expected to issue additional guidance on the IRA. Its statutory language requires the Secretary of Treasury to issue regulations and other guidance as necessary to carry out the purposes of various aspects of IRA. Should any guidance result in a change in the computation of the CMT for ratemaking purposes after this decision, PG&E will track any CMT adjustment in its Tax Memorandum Account-Electric (TMA-E) and Tax Memorandum Account-Gas (TMA-G), as applicable.³⁴⁷⁶

10.2.2.3 Gas Transmission Method Change

PG&E recently filed an Application for Change in Accounting Method with its 2021 federal income tax return,³⁴⁷⁷ pursuant to the automatic change rules under Rev. Proc. 2022-14, related to gas transmission (GT) costs. Update testimony is appropriate for “known changes due

³⁴⁷⁴ See discussion at PG&E-33, p. 3-2, lines 13-17 and fn. 4.

³⁴⁷⁵ See discussion at PG&E-33, p. 3-2, line 22 to p. 3-3, line 17.

³⁴⁷⁶ See discussion at PG&E-33, p. 3-3, lines 13-17.

³⁴⁷⁷ PG&E-33, p. 3-4, lines 5-8, indicated that PG&E expected to file the GT Method in its “next federal income tax return.” PG&E in fact submitted the method change with its 2021 federal tax return submitted on October, 4, 2022.

to governmental action such as changes in tax rates. . .”³⁴⁷⁸ PG&E included the GT Method change in its Update Testimony because application for method changes are subject to IRS approval which constitutes governmental action.³⁴⁷⁹ The Update Testimony was the first opportunity³⁴⁸⁰ to reflect this voluntary method change, which impacts GRC related plant. Repair deductions benefit ratepayers due to flow-through tax benefits in the year of the deduction (partially offset by ancillary rate base effects³⁴⁸¹), that taken together reduce revenue requirements in this GRC.

For Test Year 2023, the GT Method change overall reduced revenue requirements. The GT method change had three impacts: (1) increased flow-through deductions in 2023; (2) incorporated corollary flowback adjustments; and (3) decreased rate base due to additional normalized deferred tax liabilities related to the Section 481(a) adjustment, net of tax depreciation previously taken.³⁴⁸² The tax repair deduction amount is computed by the RO Model based on inputs from other witnesses, such as capital. Therefore, the amount of repairs reflected is influenced by the amount of capital and plant supplied by witnesses outside of Tax.

10.3 Working Cash

Working cash is a necessary component of PG&E’s authorized rate base so that PG&E can efficiently provide safe and reliable service to its customers. “Working cash is the funding provided by investors to meet utility day-to-day operations and expenditures until revenues are

³⁴⁷⁸ D.21-08-036, p. 180, citing D.07-07-004, Appendix A, p. A-36.

³⁴⁷⁹ TURN-905, PG&E Response to Data Request TURN_266-Q03, dated 9/14/22: “Applications for change in an accounting method for tax purposes require approval by the Internal Revenue Service (IRS), which constitutes governmental action.” The IRS will audit the method change and could accept it, reject it, or reduce the amounts for repairs claimed.

³⁴⁸⁰ Tr. Vol. 14, 2722:22 to 2723:7, PG&E/Battin.

³⁴⁸¹ Tr. Vol. 14, 2716:13 to 2717:4, PG&E/Battin.

³⁴⁸² See Discussion at PG&E-33, p. 3-4, lines 8-12.

collected.”³⁴⁸³ Working cash consists of (1) operational cash, or amounts needed for day-to-day operations;³⁴⁸⁴ and (2) amounts used to pay operating expenses in advance of receiving customer payments for those expenses.³⁴⁸⁵ These amounts are included in rate base to compensate investors for the permanent commitment of funds they provide to finance these requirements.³⁴⁸⁶ PG&E’s method of computing its working cash requirement aligns with CPUC Standard Practice U-16 and is generally consistent with the methods using in previous PG&E GRCs.³⁴⁸⁷

Customer deposits are addressed in this portion of the brief because they are linked to working cash in CPUC Standard Practice U-16. However, consistent with prior Commission decisions, customer deposits have been excluded as a rate base item from PG&E’s showing on working cash. In accordance with CPUC Decisions 14-08-032³⁴⁸⁸ and 19-12-056,³⁴⁸⁹ customer deposits are treated as a source of long-term debt, included in PG&E’s capital structure for ratemaking purposes.

There are several disputed issues in this GRC related to working cash and customer deposits: (1) the projected level of customer deposits for 2023 and a potential confusion between customer deposits and refundable customer advances; (2) the revenue lag and bank lag; (3) the expense lag associated with goods and services expense; and (4) the expense lags associated with

³⁴⁸³ D.20-07-038, p. 13.

³⁴⁸⁴ PG&E-10, p. 14-1, lines 11-13.

³⁴⁸⁵ PG&E-10, p. 14-1, lines 14-16.

³⁴⁸⁶ PG&E-10, p. 14-1, lines 16-18.

³⁴⁸⁷ PG&E-10, p. 14-2, lines 19-23.

³⁴⁸⁸ D.14-08-032, pp. 629-630, and pp. 720-721, FOF 310.

³⁴⁸⁹ D.19-12-056, pp. 47-48; p. 52, FOF 38; p. 54, COL 27; and p. 55, OP 6.

federal and state income tax expense. These disputed issues are discussed in the sections that follow.³⁴⁹⁰

10.3.1 Customer Deposits

PG&E projects an average customer deposits balance for 2023 of \$81.5 million.³⁴⁹¹ Cal Advocates argues for a higher balance of \$100 million.³⁴⁹² While Cal Advocates based its recommendation on PG&E's average level of customer deposits in 2019, PG&E provided more recent data to Cal Advocates in a data request and updated its recommendation to \$81.5 million based on data for 2020.³⁴⁹³ In D.20-06-003 (in Disconnection rulemaking R.18-07-005), the Commission permanently barred PG&E from requiring customer deposits for residential customers to establish or reestablish service.³⁴⁹⁴ Despite the end of Covid-related restrictions on nonresidential customer deposits in 2021, PG&E's customer deposits have continued to fall through 2021 and early 2022, indicating the PG&E's projection of \$81.5 million for 2023 will likely overstate the true level of customer deposits in 2023.³⁴⁹⁵

Regarding the ratemaking treatment for customer deposits, PG&E's revenue requirement adjustment equals the projected customer deposit balance for 2023 multiplied by a projection of

³⁴⁹⁰ TURN's original testimony on working cash contested PG&E's need for working cash based on PG&E's recent securitization debt issue. Based on PG&E's rebuttal testimony (PG&E-23-E, p. 14-1, line 23 to p. 14-3, line 19), TURN struck the relevant portions of its original testimony. See, TURN 19-R, p. 3, line 12 to p. 4, line 13; p. 6, lines 5-10; p. 17, lines 6-8; and p. 21, line 9 to p. 22, line 13.

³⁴⁹¹ PG&E-10, p. 14-15, lines 18-19.

³⁴⁹² CALPA-15, p. 31, line 2.

³⁴⁹³ PG&E-23-E, p. AppC-19.

³⁴⁹⁴ PG&E-10, p. 14-15, lines 15-17. D.20-06-003, p. 147, OPs 8 and 9.

³⁴⁹⁵ PG&E-10, p. 14-15, lines 17-19. Since PG&E's projection of customer deposits for 2023 is likely to overstate the true value, the reduction to PG&E's 2023 revenue requirement is likely to be larger than it should be. The workpaper at PG&E-10, WP 14-154 shows that the revenue requirement reduction equals the projection of customer deposits for 2023 multiplied by 3.46% (lines 13, 17 and 18). If the actual level of customer deposits for 2023 is less than PG&E's projection, the revenue requirement reduction will be too large.

the difference between the interest rate PG&E expects to pay in 2023 on customer deposits and PG&E's embedded cost of long-term debt.³⁴⁹⁶ Cal Advocates' testimony appeared to recommend that customer deposits be treated the same as customer advances. However, in a data request response, Cal Advocates confirmed that customer advances and customer deposits are not the same thing.³⁴⁹⁷ Therefore, they should not be treated in the same way and customer deposits should be treated as discussed above.

Pursuant to the Commission decisions cited above, the Commission should implement PG&E's revenue requirement for customer deposits by approving the working cash amount of \$81.5M and applying the difference between the interest rate PG&E expects to pay on customer deposits and PG&E's embedded cost of long-term debt.

10.3.2 Revenue Lag And Bank Lag

Revenue lag includes bank lag so this section of the brief considers both elements.³⁴⁹⁸ Revenue lag is an important component in the calculation of the working cash requirement that results from PG&E having to pay expenses at different times than when offsetting revenue is received from customers. This working cash requirement is estimated by a lead-lag study that includes the revenue lag.

³⁴⁹⁶ PG&E-23-E, p. 14-5, line 15 to p. 14-6, line 1.

³⁴⁹⁷ PG&E-23-E, p. 14-6, lines 8-10.

³⁴⁹⁸ PG&E's estimated revenue lag of 48.66 days includes a bank lag of 0.58 days. PG&E-10, WP 14-134, lines 17-19, 2020 values.

10.3.2.1 Bank Lag

The bank lag is the average number of days between the receipt of customer payments and the availability of funds in the bank.³⁴⁹⁹ PG&E calculated a bank lag of 0.58 days.³⁵⁰⁰ Cal Advocates, however, argued that the projected bank lag for 2023 should be 0.13 days.³⁵⁰¹

Cal Advocates appealed to the percentage of PG&E customer bills that are anticipated to be paid electronically in 2023 and implicitly assumes that electronic payments have a zero lag.³⁵⁰² They don't. While an electronic payment may appear to be instantaneous from a customer's perspective, delays in the receipt of funds occur depending on how the payment is processed.³⁵⁰³ For these and other reasons, Cal Advocates far overstates any reasonable reduction for PG&E's bank lag.³⁵⁰⁴ Reducing the revenue lag for 2023 to incorporate a reduced bank lag as implied by Cal Advocates' recommendation would assume that all other factors affecting the revenue lag remain unchanged, which is not consistent with recent history, as between 2016 and 2019, PG&E's revenue lag before including the bank lag actually increased.³⁵⁰⁵ Thus, PG&E's bank lag estimate is reasonable.³⁵⁰⁶

³⁴⁹⁹ PG&E-10, p. 14-8, lines 21-23.

³⁵⁰⁰ PG&E-10, WP 14-140, line 21.

³⁵⁰¹ CALPA-15, p. 34, lines 9-11.

³⁵⁰² PG&E-23-E, p. 14-7, lines 5-9.

³⁵⁰³ PG&E-23-E, p. 14-7, lines 9-14.

³⁵⁰⁴ PG&E-23-E, p. 14-7, line 15 to p. 14-8, line 1.

³⁵⁰⁵ PG&E-23-E, p. 14-8, lines 1-4.

³⁵⁰⁶ PG&E-23-E, p. 14-8, lines 1-5.

10.3.2.2 Revenue Lag

PG&E estimates a revenue lag of 48.66 days.³⁵⁰⁷ PG&E uses the method outlined in CPUC Standard Practice U-16 that PG&E has used in prior GRCs. TURN, however, argues for a revenue lag of 46.92 days.³⁵⁰⁸ TURN's arguments contain three principal flaws:

1. TURN ignores data showing that the revenue lag based on 2020 data is not abnormally high, as the average revenue lag for the years 2016-2019, prior to the Covid pandemic, was 48.82 days, higher than PG&E's estimate for 2020.³⁵⁰⁹
2. Despite TURN's deployment of arrearage data for 2019 and 2020 in a vain attempt to discredit the 2020 revenue lag, the revenue lag for 2019 was 52.03 days, higher than the 2020 revenue lag of 48.66 days that TURN claims is abnormal.³⁵¹⁰
3. TURN's proposal to base the 2023 GRC revenue lag forecast as an average of prior GRC *forecasts* means that TURN's revenue lag would be based in significant part on the recorded revenue lags for 2014 and 2017.³⁵¹¹

These are serious flaws; the Commission should reject TURN's proposal and adopt PG&E's revenue lag of 48.66 days.

10.3.3 Goods And Services Expense Lag

PG&E's estimate of the goods and services expense lag is 16.49 days,³⁵¹² based on a study of 471,783 invoices from 2020.³⁵¹³ This estimate is consistent with recent experience. For the years 2017 through 2019, PG&E's goods and services expense lag averaged 17.24

³⁵⁰⁷ PG&E-10, p. 14-18, Table 14-3, line 31; p. 14-19, Table 14-4, line 31; p. 14-20, Table 14-5, line 31; p. 14-21, Table 14-6, line 31.

³⁵⁰⁸ TURN-19, p. 8, lines 1-3.

³⁵⁰⁹ PG&E-10, WP 14-134, line 19.

³⁵¹⁰ PG&E-23-E, p. 14-8, line 21 to p. 14-9, line 5.

³⁵¹¹ PG&E-23-E, p. 14-9, lines 6-10.

³⁵¹² PG&E-10, Table 14-3, line 24; p. 14-19, Table 14-4, line 24; p. 14-20, Table 14-5, line 24; p. 14-21, Table 14-6, line 24.

³⁵¹³ PG&E-10, WP 14-130, line 7.

days.³⁵¹⁴ TURN argues that the goods and services expense lag should be much greater: TURN proposes that the Commission adopt an expense lag of 36.67 days.³⁵¹⁵

TURN's testimony completely overlooks the harm that this proposal may cause for PG&E's vendors. Should TURN's proposal be adopted, PG&E will be incented to take longer to pay its bills. For small vendors and diverse suppliers, working cash is not free; rather, the associated financing cost is a business expense they must bear; coming up with additional working cash in their businesses to accommodate a longer payment lag on PG&E's part may be difficult or impossible.³⁵¹⁶

PG&E's payment lag reflects that PG&E will pay vendors sooner in cases where PG&E can obtain a discount from the vendor or other favorable terms. PG&E's payment portal also allows vendors to self-select a shorter payment lag in exchange for a discounted payment. PG&E must pay its vendors on the timeframe required in its vendor contracts. TURN's testimony and recommendation are silent on these aspects of the goods and services expense lag.³⁵¹⁷

TURN attempts to support its recommendation by appealing to studies produced by PwC UK (United Kingdom) and JP Morgan.³⁵¹⁸ However, unlike PG&E's analysis of the goods and services expense lag, which is based on data that are directly applicable to the question at hand, these studies are seriously deficient:

1. We don't know how the studies were performed. Asked in a data request how the three studies calculate Days Payment Outstanding for a utility, TURN could not

³⁵¹⁴ PG&E-23-E, p. AppC-40, line 8.

³⁵¹⁵ TURN-19, p. 13, lines 10-11.

³⁵¹⁶ PG&E-23-E, p. 14-10, lines 20-23.

³⁵¹⁷ PG&E-23-E, p. 14-10, lines 24-29.

³⁵¹⁸ PG&E-23-E, p. 14-11, lines 1-3.

provide any information.³⁵¹⁹

2. The studies are silent regarding the impact of payment practices on vendors and the benefits that might be realized by different payment terms.³⁵²⁰
3. Across the three studies, only two of eleven authors are based in the United States.³⁵²¹
4. The PwC studies are dominated by companies outside of the United States and by companies that are not regulated utilities.³⁵²² Utilities are a small share of the JP Morgan study.³⁵²³ TURN wants the Commission to believe that unregulated, foreign companies should be the model for dictating payment terms to PG&E, a regulated utility in California. At the same time, TURN's witness calls PG&E's rate increase morally unsustainable.³⁵²⁴ It is doubtful that the unregulated, foreign companies that dominate these studies spend much time worrying about morality when setting their prices or payment terms for vendors.

Given the weakness of TURN's studies, the Commission should reject its recommendation and adopt PG&E's goods and services expense lag of 16.49 days.

10.3.4 Federal And State Income Tax Lags

PG&E proposes that the federal and state income tax expense lags be 48.66 days, equal to the revenue lag.³⁵²⁵ Cal Advocates proposes that the federal income tax expense lag be 90 days and the state income tax expense lag be either 75.90 days or 90 days.³⁵²⁶ TURN proposes that the federal income tax expense lag be 292 days and the state income tax expense lag be 365 days.³⁵²⁷

³⁵¹⁹ PG&E-23-E, p. 14-12, lines 3-8.

³⁵²⁰ PG&E-23-E, p. 14-11, lines 6-7.

³⁵²¹ PG&E-23-E, p. 14-11, lines 3-5.

³⁵²² PG&E-23-E, p. 14-11, lines 7-14.

³⁵²³ PG&E-23-E, p. 14-11, line 14 to p. 14-12, line 2.

³⁵²⁴ TURN-03, p. 1, lines 5-7.

³⁵²⁵ PG&E-10, p. 14-9, lines 4-7.

³⁵²⁶ PG&E-23-E, p. 14-12, line 22 to p. 14-13, line 4.

³⁵²⁷ TURN-19, p. 18, line 14.

In previous GRCs, PG&E computed the expense lag for current federal and state income taxes based on a projection of when estimated taxes will be paid during the test year.³⁵²⁸

However, there are years when PG&E will pay no income taxes, for various reasons. In PG&E's case, deductions from taxable income due to claims paid by PG&E to wildfire victims in prior years have created Net Operating Losses (NOLs) that can be carried forward and applied to taxable income in future years, reducing PG&E's income taxes.³⁵²⁹ This is projected to be the case for 2023.³⁵³⁰

OII 24 establishes the Commission's practice regarding income tax expense in the GRC: "It is the practice of the Commission, in calculating the test-year income tax expense, to assume a separate return basis considering solely utility operations. By making this assumption the Commission presumes that the utility will pay the income taxes generated by the adopted rates. However, because of a utility's affiliated or nonutility operations, its actual income tax liability will be determined as one member of a consolidated tax return. Thus, income taxes collected through authorized rates may not actually be paid, but may be used to offset tax losses of other nonutility and affiliated members of the consolidated return."³⁵³¹ Key here is the recognition that because of costs outside of the general rate case, tax expenses calculated in the GRC may not be paid in cash to the taxing authority because of tax losses from other sources.

Because the wildfire claims were paid by shareholders, the tax benefits of using these NOLs to reduce income taxes accrue to shareholders. Under the principles established in OII 24 and California utility ratemaking generally, such NOLs and the associated tax benefits do not decrease a utility's cost of service or rate base, just as the tax liability of shareholders should not

³⁵²⁸ PG&E-10, p. 14-9, lines 12-14.

³⁵²⁹ PG&E-10, p. 14-9, lines 15-28.

³⁵³⁰ Tr. Vol. 14, 2730:16-22, PG&E/Battin.

³⁵³¹ D.84-05-036, p. 18.

increase a utility's cost of service or rate base.³⁵³² If the tax benefits accrued to ratepayers rather than shareholders, ratepayers would effectively avoid the tax liability included in the cost of service.³⁵³³ Similarly, the concepts in OII 24 require that the working cash calculation not provide a secondary benefit to ratepayers that belongs to shareholders. The way to ensure this is to set the associated federal and state income tax expense lags equal to the revenue lag, resulting in no benefit to ratepayers in the calculation of working cash.³⁵³⁴

Cal Advocates and TURN oppose PG&E's proposed federal and state income tax expense lags and propose longer lags. The longer lags proposed by Cal Advocates and TURN work to reduce working cash and rate base, thus running afoul of the OII 24 principle discussed immediately above, that the working cash calculation not provide a secondary benefit to ratepayers.³⁵³⁵

Cal Advocates argues that PG&E's income tax expense lags should be based on what it calls "PG&E's initial forecast."³⁵³⁶ PG&E's original calculations of the federal and state income tax expense lags were superseded by testimony served on August 27, 2021.³⁵³⁷ PG&E's initial calculations of the income tax expense lags were incomplete and did not take into account the extensive analysis of Net Operating Losses and PG&E's current tax situation that is found in PG&E's August 27, 2021 testimony.³⁵³⁸

³⁵³² PG&E-10, p. 14-9, lines 24-28. p. 14-11, lines 13-28.

³⁵³³ PG&E-10, p. 14-12, lines 7-10.

³⁵³⁴ PG&E-10, p. 14-12, lines 10-17.

³⁵³⁵ Mathematically, if an expense lag for a particular expense category in PG&E-10, Tables 14-3 to 14-6 is less than the revenue lag, working cash is increased from what it would be otherwise because PG&E pays the expense before offsetting revenue is received. Conversely, if the expense lag exceeds the revenue lag, working cash is reduced. When the two lags are the same, there is no impact on working cash.

³⁵³⁶ CALPA-15, p. 3, lines 15-17.

³⁵³⁷ PG&E-23-E, p. 14-13, lines 9-12.

³⁵³⁸ PG&E-10, p. 14-9, line 3 to p. 14-14, line 29.

Cal Advocates states: “in the recent past, the Commission has previously adopted a tax expense lag days forecast calculated based on the forecasted payment date even while the tax payments were not recorded or foreseen.”³⁵³⁹ However, this approach would produce an income tax expense lag of approximately 38 days, very close to PG&E’s recommendation of 48.66 days.³⁵⁴⁰ Thus, Cal Advocates’ reference to a previous Commission approach supports PG&E’s recommendation.

TURN recommends much longer federal and state income tax lags: 292 days for the federal income tax expense lag and 365 days for the state income tax expense lag.³⁵⁴¹ However, although TURN claims that its calculation is valid, it is not. That is because TURN has effectively confused cash accounting and accrual accounting.³⁵⁴² TURN’s calculation is based on the assumption that income taxes are due each day, but that is not correct for cash payments; income taxes are not remitted on a daily basis but on a quarterly basis. Thus, a basic assumption in TURN’s calculation is incorrect.³⁵⁴³

What TURN is really doing is calculating the percentage of annual tax expense paid during the year and then multiplying that percentage by 365 days. For a year in which the total tax expense was paid, TURN’s method would calculate an expense lag of zero. But that would clearly be incorrect because income taxes are not remitted daily.³⁵⁴⁴

³⁵³⁹ CALPA-15, p. 33, lines 19-21.

³⁵⁴⁰ Quarterly estimated income tax payments are due on April 15, June 15, September 15, and December 15 of the following year. This results in quarterly expense lags (measured from the midpoint of the quarter to the payment due date) of 60, 30.5, 31, and 30 days, respectively, which average to 37.875 days.

³⁵⁴¹ TURN-19, p. 18, lines 13-14.

³⁵⁴² PG&E-23-E, p. 14-17, lines 7-9.

³⁵⁴³ PG&E-23-E, p. 14-17, lines 10-17.

³⁵⁴⁴ PG&E-23-E, p. 14-17, line 18 to p. 14-18, line 10.

But if cash tax payments are less than the authorized tax expense, what happens to the difference? The answer, as revealed by PG&E's financial statements, is that the cash flows related to federal and state income taxes have been a prime source for funding PG&E's capital expenditures during the period from 2011 through 2021. Those capital expenditures are embedded in capital assets that serve PG&E customers today and in the future.³⁵⁴⁵

For all of the reasons discussed above, the Commission should adopt PG&E's expense lags for federal and state income taxes and reject Cal Advocates' and TURN's recommendations.

10.4 Electric And Gas Distribution, Electric Generation, Gas Transmission And Storage Rate Base

Rate base is mainly made up of the unrecovered net investments in utility property (i.e. plant less accumulated depreciation). PG&E, as in prior GRCs, proposes to true up its rate base for 2021 and 2022 to include new capital expenditures installed during those years that are used and useful in providing utility service to customers.

Cal Advocates recommends removing from rate base and therefore from PG&E's 2023-2026 capital revenue requirements, recorded and/or forecast capital expenditures tracked in the following memorandum accounts: (1) Community Rebuild Program costs tracked in the Catastrophic Events Memorandum Account (CEMA)³⁵⁴⁶ and (2) wildfire mitigation costs tracked in the Wildfire Mitigation Plan Memorandum Account (WMPMA).³⁵⁴⁷

For Community Rebuild Program capital expenditures tracked in CEMA, Cal Advocates seeks to delay cost recovery of \$156 million of recorded capital expenditures in 2019 and

³⁵⁴⁵ PG&E-23-E, p. 14-18, lines 13-20. Additional analysis is found at PG&E-23-E, p. 14-18, line 20 to p. 14-19, line 30.

³⁵⁴⁶ CALPA-05, p. 53, line 32 to p. 55, line 6.

³⁵⁴⁷ CALPA-05, p. 19, lines 1-20.

2020³⁵⁴⁸ and \$269 million in 2021-2022 forecast capital expenditures.³⁵⁴⁹ Cal Advocates also seeks to delay approval of cost recovery of \$350 million in years 2023-2026 for capital expenditures forecast in this GRC filing.³⁵⁵⁰ For capital expenditures tracked in WMPMA, Cal Advocates seeks to delay cost recovery of \$421 million forecast capital expenditures in 2021 and 2022 .³⁵⁵¹

Cal Advocates argues that costs recorded and tracked in memorandum accounts will ultimately be reviewed in future proceedings to determine the reasonableness of the expenditures being tracked.³⁵⁵² Cal Advocates contends that Community Rebuild capital expenditures can only be reviewed and recovered through a CEMA-related application, and 2021 and 2022 capital expenditures for wildfire mitigation and system hardening can only be reviewed and recovered through a separate application for reasonableness review of amounts recorded in the WMPMA.³⁵⁵³ Cal Advocates argues that the capital additions are “unexamined” costs.³⁵⁵⁴

10.4.1 Community Rebuild Program Costs Are Not Limited to Recovery Through the Catastrophic Events Memorandum Account

In regard to the Community Rebuild Program, Cal Advocates’ underlying premise and assumption that all capital expenditures should be recorded to CEMA is wrong. PG&E’s CEMA costs for the 2018 Camp Fire (still unrecovered) relate to its initial restoration and repair efforts

³⁵⁴⁸ CALPA-05, p. 55, line 4.

³⁵⁴⁹ CALPA-05, p. 48, lines 14-20; p. 49; and p. 54, lines 19-28. See p. 49 (extract from PG&E-04, WP 23-24, Table 23-13 (2021-2022), at: lines 8-13 (MAT 95F); lines 23-25 (MATs 3QA, 50A, and 50B); and lines 30-34 (MATs 3M, 25 and 74).

³⁵⁵⁰ CALPA-05, p. 54, lines 7-9. See p. 49 (extract from PG&E-04), WP 23-31, Table 23-13 (2023-2026), at: lines 8-13 (MAT 95F); lines 23-25 (MATs 3QA, 50A, and 50B); and lines 30-34 (MATs 3M, 25 and 74).

³⁵⁵¹ CALPA-05, p. 19, lines 1-20. Also see Appendix C, p. C-2 (PG&E’s response to Data Request Cal- Advocates_117-Q05(a)) for 2021 and 2022 forecast amounts.

³⁵⁵² CALPA-05, p. 5, lines 20-31.

³⁵⁵³ CALPA-05, p. 17, line 15 to p. 19, line 20.

³⁵⁵⁴ CALPA-05, p. 54, lines 2-5.

following the fire. This included restoring overhead electrical power lines following the fire and connecting service to customers who were able to accept service immediately after the fire.

These like-for-like restore/repair activities are traditionally recorded for recovery in CEMA.

In contrast, the Community Rebuild Program forecast for 2023-2026 presented in this GRC is for the undergrounding of overhead lines to mitigate fire risk, not CEMA work for restoring service. That is, the Community Rebuild Program extends well beyond the like-for-like restoration work typically recovered in CEMA, and contrary to Cal Advocates' assumption, it should not be construed as CEMA work just because it is being completed in the town of Paradise. Once overhead facilities had been restored in Paradise as CEMA activities, all subsequent activities pertaining to those lines (whether PG&E hardens, undergrounds, or performs some other wildfire mitigation activity on them) should not be construed as a CEMA activity. The Community Rebuild Program undergrounding work, which is part of PG&E's undergrounding program, is akin to a system-improvement project that should be deemed to be recoverable in the GRC on a forecast basis beginning in 2023.

Moreover, given the time period at issue (2023-2026), the costs can be reasonably forecast in a GRC. CEMA cost recovery is appropriate when costs cannot be reasonably forecast to be included in the GRC.

10.4.2 Costs For Capital Work That Is Used and Useful Is Properly Included As Utility Plant In A GRC

As the Commission discussed in the 2020 GRC decision, amounts attributable to capital additions that are used and useful in providing utility service can be reviewed and authorized to be included in Utility Plant in a GRC:

Utility plant is the value of undepreciated assets that PG&E uses to provide service. These include assets that are currently used and useful in providing utility service to customers and the capital investments PG&E is authorized to add to its plant (capital additions). It is the sum of assets that the Commission authorized PG&E to recover and the capital additions PG&E requests for authority to add to the Utility Plant.

We review the reasonableness of capital expenditures that PG&E requests to add to Utility Plant in various other sections of this decision, such as Energy Supply, Gas Distribution, and Electric Distribution, among many others. Using the plant assets that the Commission previously authorized and the capital additions we authorize in this decision, the RO model calculates the balance of the Utility Plant.³⁵⁵⁵

Cal Advocates' arguments that any capital additions for wildfire system hardening recorded in the WMPMA or the Community Rebuild Program may not be reviewed and approved in this proceeding ignores this bedrock ratemaking principle. Assets that are used and useful (even if subject to an after-the-fact review) are properly included in Utility Plant in a GRC.

First, as noted above, the Commission does approve new capital additions in the GRC that are explained in the various sections of the line of business testimony. PG&E's recorded forecast costs for its wildfire hardening and Community Rebuild Program capital expenditures for 2021, 2022 and beyond that PG&E seeks to include in Utility Plant are described in PG&E-04, Chapter 4.3 (System Hardening, Enhance Automation, and PSPS Impact Mitigations), PG&E-04, Chapter 23 (Community Rebuild Program), and supporting workpapers.³⁵⁵⁶ This information is sufficient for PG&E to meet its burden to show the capital expenditures already in service are "used and useful" to provide electric distribution services and should be included in Utility Plant when forecast to go into service.

³⁵⁵⁵ D.20-12-005, p. 261 (emphasis added).

³⁵⁵⁶ PG&E-04, p. 4.3-4, line 5 to p. 4.3-8, line 10; p. 23-5, line 4 to p. 23-12, line 13. *See e.g.*, PG&E-04, WP 4-38 to WP 40 (describing 2021-2022 activities for the Partial Voltage Detection program recorded to MWC 21); WP 4-41 to WP 50 (describing 2021-2022 activities for the Expanded Weather State Deployment program recorded to MWC 21); WP 4-85 to WP 4-87 (describing 2021-2022 activities for Distribution Line Automation program recorded to MWC 49/MAT 49A); WP 4-97 to WP 4-99 (describing 2021-2022 activities for the Single Phase Recloser program recorded to MWC 49/MAT 49T); WP 4-100 to WP 4-103 (describing 2021-2022 activities for the Distribution Line Sectionalizing program recorded to MWC 49/MAT 49H); WP 4-111 to WP 4-115 (describing 2021-2022 activities for the Distribution Grid Sensors program recorded to MWC 49/MAT 49I); WP 4-122 to WP 4-124 (describing 2021-2022 activities for the Expulsion Fuse Replacement program recorded to MWC 2A (MAT 2AP)).

Third, Cal Advocates had almost a year to conduct discovery on the recorded and forecast 2021 and 2022 capital expenditures that PG&E seeks to include in Utility Plant in this proceeding and thus there is no reason for them to argue that the expenditures are “unexamined.”³⁵⁵⁷ While it is PG&E’s obligation to provide a *prima facie* just and reasonable showing regarding these capital expenditures, Cal Advocates had the burden to produce evidence in support of its position that the capital expenditures PG&E seeks to include in its recorded utility plant are not used and useful.³⁵⁵⁸ Cal Advocates had an opportunity to and did conduct discovery about the recorded and forecast capital expenditures for 2020 through 2022. Its testimony does not raise a reasonable doubt about the reasonableness of the capital expenditures for wildfire mitigation or hardening incurred to implement an approved Wildfire Mitigation Plan recorded in the WMPMA or the undergrounding work being completed in the Community Rebuild Program. Nor does it provide any evidence to negate PG&E’s showing that the capital expenditures are “*used and useful in providing utility service to customers.*”³⁵⁵⁹ Also as the expenditures are not included in PG&E’s Track 2 request, there is no outstanding application proceeding where these costs are being considered. Delaying cost recovery further of amounts included in this GRC is unnecessary and impacts PG&E’s financial health and should not be required.³⁵⁶⁰ If the costs were for any reason disallowed in a future application proceeding, PG&E could make a change to its GRC revenue requirement to reflect the Commission’s order. The theoretical possibility of such a disallowance in some future proceeding, however, is not a reason to disallow a ratebase true up in this proceeding to provide PG&E with revenue for future investments.

³⁵⁵⁷ CALPA-05, p. 54, lines 2-5.

³⁵⁵⁸ See D.21-08-036, p. 10.

³⁵⁵⁹ D.20-12-005, p. 261 (emphasis added).

³⁵⁶⁰ PG&E-14, p. 3-1, line 29 to p. 3-2, line 8.

In summary, under the principals of forecast ratemaking, PG&E should be encouraged to put forward recorded plant and known future costs associated with activities tracked in memorandum accounts in its GRC requests to provide increased revenue requirement and rate predictability and minimize the burden associated with separate memorandum account incremental cost recovery applications on the Commission and parties.

10.5 Other Operating Revenues

Other Operating Revenues (OORs) are revenues PG&E receives from transactions not directly associated with the distribution, generation, gas transmission, or sale of electric energy or natural gas. Revenues from these transactions are generated through, and supported by, activities whose distribution, gas transmission, and generation-related costs are included in the proposed distribution, gas transmission, and generation revenue requirements in this GRC. OORs are estimated separately and subtracted from the GRC revenue requirement because OORs reduce the amounts that need to be collected from customers through rates charged for gas and electric service.³⁵⁶¹

PG&E requests that the Commission adopt its 2023 forecast of electric and gas distribution OORs of \$188.6 million and \$33.6 million, respectively, and the forecast of electric generation and gas transmission and storage of \$13.5 million and \$11.0 million, respectively.³⁵⁶² PG&E did not provide rebuttal testimony on OORs because no party disputed PG&E's methodology and forecast.

10.6 Calculation of the Revenue Requirement

PG&E requests that the Commission adopt its estimating method and results of operations (RO) model used to calculate revenue requirements in this case.

³⁵⁶¹ PG&E-10, p. 16-1, lines 10-24.

³⁵⁶² PG&E-10, p. 16-1, lines 26-30.

The estimating method gathers inputs on operating expense and capital components for CPUC-jurisdictional functions using an Unbundled Cost Category (UCC) format that supports a full summary of earnings for each UCC.³⁵⁶³ The RO model (used in all PG&E GRCs since 2007 and two recent GT&S cases) maintains the UCC organization to compute revenue requirements that can be summarized to electric and gas distribution, electric generation, and GT&S functions.³⁵⁶⁴

Cal Advocates relied on the RO model (with different inputs and one formula error correction as instructed by PG&E) to prepare its revenue requirements recommendation.³⁵⁶⁵ PG&E did not provide rebuttal on calculation of the Revenue Requirement because no party disputed it.

10.7 Payroll & Other Taxes

PG&E requests that the Commission adopt its calculation method and resulting 2023 forecast for payroll taxes and other taxes as presented in Opening Testimony.³⁵⁶⁶ The method used for computing payroll taxes is the same method used in GRCs since 2003. After simplifying and incorporating the methodology into the Results of Operations (RO) model in the 2007 GRC, the calculation uses an expected payroll tax factor derived from 2020 base year operations and maintenance (O&M) adjusted labor that is then applied to O&M labor for forecast years.³⁵⁶⁷

Other taxes consist of business license taxes, federal highway use taxes, insurance excise taxes, a San Francisco Health Care Security Ordinance fee, and a timber yield tax; the taxes and

³⁵⁶³ PG&E-10, p 17-3, lines 5-33.

³⁵⁶⁴ PG&E-10, p. 17-4, lines 1-10.

³⁵⁶⁵ CALPA-14, p. 3, line 8 to p. 4, line 5.

³⁵⁶⁶ PG&E-10, p. 9-1, lines 26-28.

³⁵⁶⁷ PG&E-10, p. 9-2, lines 1-18.

calculation methods are further detailed in opening testimony.³⁵⁶⁸ Because none of the parties opposed PG&E's forecast for Payroll Taxes³⁵⁶⁹ or Other Taxes,³⁵⁷⁰ PG&E has no rebuttal testimony on this topic.

10.8 Administrative And General Allocation Factors And Franchise Fee Factor.

PG&E requests that the Commission adopt: (1) the methodology used to allocate total Company A&G expenses to capital, Below-the-Line and non-utility affiliates; (2) the unbundling and allocation of utility common A&G expenses to electric distribution, gas distribution, electric generation, gas transmission and storage functional areas for use in this GRC and in other, non-GRC, Commission ratemaking mechanisms; and (3) other high-level adjustments.³⁵⁷¹

PG&E did not provide rebuttal testimony on Administrative and General Expense allocations, unbundling factors and other high-level adjustments because no party disputed PG&E's methodology or factors.

³⁵⁶⁸ PG&E-10, p. 9-7, line 1 to p. 9-8, line 6.

³⁵⁶⁹ CALPA-14, p. 10, lines 10-16.

³⁵⁷⁰ CALPA-14, p. 12, lines 18-19.

³⁵⁷¹ PG&E-10, p. 8-1, line 17 to p. 8-2, line 5.

11. Post Test-Year Ratemaking (PTYR) (Exhibit PG&E-11)

11.1 Post Test-Year Rate Mechanism

Attrition, or Post Test-Year Ratemaking (PTYR), is necessary to provide PG&E with the funds it needs in between rate case test years, in this case 2024 through 2026, to provide safe and reliable service for its customers. In the last two decades, the Commission has approved two-part PTYR mechanisms for the IOUs that separately escalate Operations and Maintenance (O&M) expenses and capital-related costs. The Commission recently summarized the rationale for the two-part PTYR mechanism in a decision adopting 2022 and 2023 PTYR mechanisms for SDG&E and SoCalGas as follows:

In D.19-09-051, the Commission adopted a two-part attrition mechanism for PTY 2020 and 2021, by which O&M and capital expenses are separately escalated as it rationalized that in this GRC, the main factors affecting projected increases in costs anticipated during the PTYs are dissimilar for O&M and capital additions.

For O&M expenses, the decision found it more appropriate to base labor and non-labor O&M costs on the IHS Markit Global Insight (Global Insight) forecast because Global Insight escalation rates are specific to the utility industry and more accurately reflect SDG&E's and SoCalGas's inflationary cost increases. In contrast, the decision added that escalation based on CPI, a broad wholesale pricing index, reflects price increases for goods and services in general and does not sufficiently capture the O&M escalation inputs of SDG&E SoCalGas in this instance.³⁵⁷²

After summarizing its prior rationale for adopting the two-part PTYR mechanism, the Commission determined to continue the mechanism for SDG&E and SoCalGas for an additional two-year period.³⁵⁷³

The Commission clearly recognized that the factors driving expense and capital escalation are different and require different approaches in the 2006 SCE GRC. The Commission discussed the differences between the two approaches as follows:

The attrition methodologies adopted in D.85-12-076 and used during much of the 1980s and 1990s, among other things, determined attrition year revenue requirements by escalating operation and maintenance expenses by forecasted

³⁵⁷² D.21-05-003, pp. 10-11 (citations omitted) (emphasis added).

³⁵⁷³ D.21-05-003, p. 12.

inflation factors [citation omitted] and determining capital related costs based on forecasted attrition year plant additions. SCE essentially followed this procedure in determining its PTY revenue requirements, although it used a budget based approach for forecasting PTY plant additions. DRA also used this methodology in its alternate PTY recommendation. DRA used a four-year average of escalated historic and forecasted plant additions (2004 – 2006) to estimate plant additions for 2007 and 2008. *There is merit to this type of analysis because the increase in revenue requirements can directly be tied to the principal factors that cause the operational attrition — inflation as it relates to expenses and annual plant additions. For capital-related costs, the reasonableness of the increases relates directly to the reasonableness of the adopted plant additions.*³⁵⁷⁴

The Commission then explained why a simplified approach (similar to Cal Advocates' primary PTYR mechanism in this proceeding) was not appropriate:

The question of whether simplified methods to basic ratemaking principles are worth pursuing can only be answered on a case-by-case basis. In this case, because of the effect on SCE's future capital expenditure levels, we will not use the CPI methodology proposed by DRA. The plant additions implicit in DRA's PTY CPI proposal are significantly less than what we, by this decision, are adopting for SCE for test year 2006. Such reductions are counter to our commitment, as discussed previously, to facilitate the replacement of SCE's transmission and distribution infrastructure in a timely and efficient manner.³⁵⁷⁵

The Commission has adopted a two-part PTYR mechanism for SCE in almost every GRC since 2003. In its most recent GRC decision on an SCE GRC, the Commission explained its rationale as follows:

We find it reasonable to authorize a PTYR mechanism during this GRC cycle in order to give SCE an opportunity to offset some inflationary price increases and to recover costs for capital investments, particularly investments for wildfire risk mitigation, which are necessary for SCE to continue to provide safe and reliable service. Since O&M expenses and capital costs affect revenue requirement differently, we adopt a two-part mechanism that separately escalates O&M expenses and capital-related costs.³⁵⁷⁶

In PG&E's 2014 GRC (the last fully-litigated PG&E GRC), the Commission adopted a two-part PTYR mechanism. The Commission stated:

³⁵⁷⁴ D.06-05-016, pp. 300-301 (emphasis added).

³⁵⁷⁵ D.06-05-016, p. 304.

³⁵⁷⁶ D.21-08-036, pp. 546-547.

We adopt a two-part mechanism to capture distinctions driving attrition increases (a) for expenses versus (b) for capital expenditures. We decline to adopt DRA's primary proposal to set post-test-year revenue increases simply based on a single index, with no distinction between expenses versus capital additions. While applying a single index, as proposed by DRA, offers simplicity, we conclude that such an approach fails to adequately capture the distinctions between expense and capital expenditure attrition. We also decline to apply the CPI as an escalation factor. The CPI reflects consumer retail price changes, not the escalation in wholesale purchases of utility goods and services. Accordingly, we generally adopt industry-specific escalation factors, rather than use of the CPI.³⁵⁷⁷

All Commission decisions in fully-litigated GRCs since PG&E's 2014 GRC for the IOUs have similarly adopted the traditional approach to PTYR, using separate estimates of expense and capital escalation,³⁵⁷⁸ as opposed to the approach recommended by Cal Advocates in this proceeding. The Commission described its rationale for approving this mechanism in multiple GRCs as follows:

We find that this PTYR mechanism strikes an appropriate balance between the goals described above as well as the parties' different positions. Even though applying a percentage increase based on CPI, as suggested by ORA's primary recommendation, is simple, it does not reflect how utilities incur costs. Since O&M expenses and capital expenditures affect the revenue requirement differently, we find a two-part attrition mechanism, where O&M expenses and capital-related revenues are separately escalated, is reasonable. These considerations form the bases for the two-part attrition mechanisms that were adopted in D.13-05-010 and D.14-08-032.³⁵⁷⁹

As discussed below, PG&E's proposed two-part PTYR mechanism will allow it to provide safe and reliable service to customers during the attrition years while retaining a reasonable opportunity to recover its costs and is fully consistent with Commission precedent discussed above.

³⁵⁷⁷ D.14-08-032, p. 653.

³⁵⁷⁸ This includes: D.15-11-021, p. 557, OP 19(a) and (b) (SCE's 2015 GRC); D.19-05-020, p. 436, OP 4(a) and (b) (SCE's 2018 GRC); D.19-09-051, p. 776, OP 4(a) and (b) (Sempra 2019 GRC); and (SCE's 2021 GRC) D.21-08-036, pp. 644-646.

³⁵⁷⁹ D.15-11-021, pp. 390-391.

11.1.1 PG&E's Post Test Year Proposal

Our proposed mechanism models capital revenue requirement growth based on adopted test year (TY) plant additions, thereby allowing us to reflect in attrition year revenue requirements, the growth in rate base, depreciation expense, and taxes that will occur irrespective of expense growth.³⁵⁸⁰ The expense component of the mechanism applies specific escalation rates to adopted test year expenses with the exception of: (1) gas storage costs; (2) vegetation management costs; (3) declining expenses associated with the planned closure of DCPD; (4) TOU mandatory transitions to revised TOU periods and Peak-Day Pricing (PDP) event hour revision; (5) healthcare and other administrative and general (A&G) corporate items; (6) wildfire excess liability insurance;³⁵⁸¹ and, (7) the newly-implemented EPSS program.³⁵⁸² Without such separate treatment of expense and capital revenue requirement growth, PG&E would normally face a revenue requirement shortfall that cannot be solved even with radical reductions to capital spending. Based on all litigated decisions since PG&E's 2014 GRC, the Commission has now accepted the regulatory practice of providing for a two-part attrition mechanism, that separately escalates O&M expenses and capital-related costs.

For capital, PG&E's proposal recommends escalating the majority of adopted TY net capital additions,³⁵⁸³ except for gas storage, nuclear generation, hydro generation, corporate real estate, and electric distribution system hardening and the community rebuild program, for which

³⁵⁸⁰ PG&E-11-E, p. 1-1, lines 23-28.

³⁵⁸¹ PG&E-11-E, p. 1-4, lines 8-20. Note that PG&E, Cal Advocates and TURN have reached a settlement agreement on wildfire liability insurance, which, if adopted, will remove PG&E's proposed wildfire insurance attrition adjustment. Joint Motion of Pacific Gas and Electric Company, The Utility Reform Network and The Public Advocates Office at the California Public Utilities Commission for Expedited Approval and Adoption of the Attached Settlement Agreement on Insurance-Related Issues (Joint Motion for Adoption of Insurance Settlement) (Oct. 7, 2022), Attachment A, Settlement Agreement, p. 4, Section 3.2.2.4.

³⁵⁸² PG&E-11-E, p. 1-4, line 20.

³⁵⁸³ PG&E-11-E, p. 1-7, lines 30-33.

PG&E proposes that additions for each category be based on a bottom up forecast.³⁵⁸⁴

Separately, PG&E forecast retirements for certain common and general FERC accounts that are based on a predetermined schedule that reflects authorized service lives (vintage retirements).³⁵⁸⁵ PG&E also requests that the Commission adopt the other rate base PTY revenue adjustments in gas storage, gas distribution and DCPD summarized in Table 11-1 below.³⁵⁸⁶

TABLE 11-1
OTHER RATE BASE PTY REVENUE ADJUSTMENTS
(MILLIONS OF NOMINAL DOLLARS)

Line No.	Description	2023	2024	2025	2026
1	Gas Storage	\$(104)	\$-	\$-	\$-
2	Gas Distribution Cost Recovery Proposal	47	\$93	\$139	\$186
3	Other DCPD retirement adjustments	66	66	19	\$-
4	Total	\$9	\$159	\$158	\$186

11.1.2 PG&E's Cost-Based Proposal Is the Only Mechanism Sufficient To Cover PG&E's Costs

The Commission should adopt PG&E's proposal for a traditional PTYR mechanism that models capital revenue requirement growth based on adopted TY plant additions and applies escalation rates to adopted TY expenses. There are two key components of the recommendation: (1) capital costs must be tied to test year capital additions and determined separately from expenses;³⁵⁸⁷ and, (2) expense escalation should be computed based on escalation factors that reflect cost increases in the goods and services PG&E procures.³⁵⁸⁸

PG&E emphasizes the capital aspect of the request here because the issue has not always been fully reflected in intervenors' recommendations, which often suggest that a utility should

³⁵⁸⁴ PG&E-11-E, p. 1-8, lines 4-18.

³⁵⁸⁵ PG&E-11-E, p. 3-1, lines 26-29.

³⁵⁸⁶ PG&E-11-E, p. 3-7, line 11 to p. 3-8, line 17 and Table 3-3.

³⁵⁸⁷ PG&E-11-E, p. 1-1, lines 23-26; p. 1-6, lines 26-29; p. 1-7, lines 2-5.

³⁵⁸⁸ PG&E-11-E, p. 1-7, lines 6-8.

receive a PTYR increase that solely reflects growth in the CPI or some other measure of reasonable cost escalation.³⁵⁸⁹

Cal Advocates once again makes a CPI-based proposal to adjust the overall revenue requirement by a specific escalation factor, also referencing attrition year increases granted to other utilities.³⁵⁹⁰ While PG&E agrees that TY revenue requirement escalation (at appropriate rates) makes sense for setting funding levels for utility *expenses*, such as wages, materials, and health care costs, generalized escalation is not a reasonable or prudent method for determining *capital* revenue requirement increases during the PTY period. Capital revenue requirement changes are determined almost entirely by the relationship between capital additions and depreciation.³⁵⁹¹ When capital additions exceed depreciation, rate base and the related capital revenue requirement components increase.³⁵⁹² The revenue requirement increase *percentage*, in turn, depends on how these capital cost increases compare to existing rate base and plant.³⁵⁹³ *This happens irrespective of inflation.*

Additionally, escalating PG&E's TY revenue requirement would be especially inappropriate in this GRC given that PG&E's spending for capital projects in this GRC period is driven not just by increases in costs of material and labor, but also PG&E's adherence to AB 1054 which requires the exclusion of the first \$3.21 billion of wildfire capital expenditures from earning an equity return (hereinafter "non-equity earning rate base").³⁵⁹⁴ PG&E explained in Exhibit PG&E-10, Chapter 15, that a portion of the capital spend in TY 2023 is subject to the

³⁵⁸⁹ PG&E-11-E, p. 1-1, lines 29-33.

³⁵⁹⁰ CALPA-16, p. 2, lines 6-11; p. 5, line 9 to p. 7, line 2.

³⁵⁹¹ PG&E-11-E, p. 1-1, line 33 to p. 1-2, line 7.

³⁵⁹² PG&E-11-E, p. 1-2, lines 7-9.

³⁵⁹³ PG&E-24-E, p. 1-9, lines 23-25.

³⁵⁹⁴ PG&E-24-E, p. 1-11, lines 20-25.

\$3.21 billion AB 1054 equity return exclusion³⁵⁹⁵ and wildfire mitigation capital expenditures in years 2024-2026 would again become eligible for both debt and equity financing.³⁵⁹⁶ Due to this adjustment in the TY, there is not a steady increase between PG&E's TY and PTY wildfire capital additions' revenue requirements. Instead, there is a noticeable increase to capital revenue requirements for PG&E's wildfire capital expenditures in the PTYs compared to the TY to reflect that capital additions will earn a normal rate of return.³⁵⁹⁷ As a result, a PTYR mechanism that simply escalates TY revenue requirement would not provide PG&E with adequate funding for the vital wildfire mitigation investments it must undertake during the PTY and an opportunity to earn a full authorized return for the capital expenditures that are not subject to the provisions of AB 1054.³⁵⁹⁸

11.1.3 Summary Of Parties' PTYR Proposals

For the reasons explained below, the Commission should reject Cal Advocates' and TURN's proposed methodologies as they do not allow PG&E to provide safe and reliable service to customers and retain a reasonable opportunity to earn a rate of return.

Table 11-2 below summarizes Cal Advocates' and TURN's respective PTYR recommendations. The amounts in the table below and discussed in Section 11 of this brief do not reflect changes in escalation rates and tax changes that were included in PG&E's Update Testimony served on September 6, 2022. PG&E's revenue requirement request increases for its attrition years was updated to \$1.048 billion from \$1.018 billion for 2024, \$860 million from \$755 million for 2025, and \$680 million from \$561 million for 2026 as compared to PG&E's March 10, 2022 Amended Application.³⁵⁹⁹

³⁵⁹⁵ PG&E-10, p. 15-11, Table 15-2.

³⁵⁹⁶ PG&E-24-E, p. 1-11, lines 25-29.

³⁵⁹⁷ PG&E-24-E, p. 1-11, line 29 to p. 1-12, line 2.

³⁵⁹⁸ PG&E-24-E, p. 1-12, lines 2-7.

³⁵⁹⁹ PG&E-33, p. 1-1, line 20 to p. 1-2, line 2.

TABLE 11-2
SUMMARY OF CAL ADVOCATES AND TURN PTYR RECOMMENDATIONS
(MILLIONS OF DOLLARS)

Line No.	Item at Issue	PG&E Recommendation	Cal Advocates Primary ^(a)	TURN Primary ^(b)
1	Estimated attrition revenue increase/(decrease)	2024: \$1,018 (7%) 2025: \$755 (5%), and 2026: \$561 (3%)	2024: \$301 (2.3%), 2025: \$(55) (-0.4%), and 2026: \$(227) (-1.7%)	Not calculated
2	Wage Escalation Rates	For represented employees: IBEW and ESC 3.75%, SEIU 3%; For non-represented: 3.07%	Not addressed	Escalate at the All-Urban Consumer Price Index (CPI-U)
3	Materials and Services (non-labor) Escalations	Escalate using IHS Markit escalation rates for 2024 - 2026	Not addressed	Escalate at CPI-U
4	Medical Program Escalations	Escalate at 4.61% for 2024 - 2026	Not addressed	Escalate at CPI-U
5	Capital Additions	Escalate 2023 net capital additions using IHS Markit index except bottom-up forecasts for Diablo Canyon (DCPP), Hydro, CRESS, Gas Storage, and Electric Distribution wildfire mitigation capital.	Not addressed. In general, limited PTYR revenue requirement increases to 3%, except does not oppose PG&E's proposed discrete capital adjustments for DCPP and Gas Storage.	(1) Use bottom-up forecasts for Category 1 (Wildfire hardening, DCPP, and Gas Storage) (2) Escalate 7-year average (2015 - 2021) capital additions using a weighted average IHS Markit capital index for Category 2 (All others).
6	Discrete expense adjustments			
6a	Gas Storage Expense Forecasts	2024: \$22 2025: \$24, and 2026: \$46	Not oppose	2024: \$18 2025: \$18, and 2026: \$25
6b	Vegetation Management Program Forecasts	2024: \$1,033 2025: \$983, and 2026: \$900	No discrete adjustments	Not oppose
6c	Planned Closure of DCPP-Expense Forecast	2024: \$315 2025: \$167, and 2026: \$0	Not oppose	2024: \$264 2025: \$140, and 2026: \$0
6d	TOU and Peak-Day Pricing (PDP) Adjustments	2026: \$12	Not oppose	Escalate at CPI-U
6e	Healthcare and Other A&G items	2024: \$1,000 2025: \$1,025, and 2026: \$1,047	No discrete adjustments	Escalate at CPI-U
6f	Wildfire Excess Liability Insurance	2024: \$783 2025: \$783, and 2026: \$783	No discrete adjustments	Escalate at CPI-U
6g	Enhanced Powerline Safety Settings (EPSS)	2024: \$146 2025: \$141, and 2026: \$134	No discrete adjustments	2024: \$89 2025: \$91, and 2026: \$93
6h	Public Safety Power Shutoff Events (PSPS)	N/A	N/A	2024: \$43 2025: \$44, and 2026: \$45
7	Z-factor mechanism	Apply Z-factor to TY and PTYs Advice Letter filing	Oppose Z-factor mechanism in TY	Oppose Advice Letter filing, continue with application

(a) Cal Advocate's alternative proposal is to recognize 2% annual O&M cost reductions in PTYs.

(b) TURN's alternative proposal is to escalate at CPI-U plus 50 basis points.

11.1.4 Cal Advocates Proposals Should Be Rejected

Cal Advocates' *primary* recommendation is to set post-test year revenue increases at 3.0 percent per year. Cal Advocates also recommends other modifications to PG&E's proposals for vegetation management costs;³⁶⁰⁰ Human Resources,³⁶⁰¹ Shared Services and IT,³⁶⁰² and A&G;³⁶⁰³ and wildfire liability insurance.³⁶⁰⁴ Cal Advocates does not address the EPSS program. *Alternatively*, Cal Advocates recommends that in the event the Commission does not adopt Cal Advocates' primary proposal, then the Commission should recognize a 2 percent annual O&M cost reductions in the PTYs.³⁶⁰⁵

11.1.4.1 The Commission Should Not Adopt Cal Advocates' Primary Recommendation For 3 Percent Single-Index Escalation Based On The Consumer Price Index Because It Would Significantly Underfund The Utility During The Attrition Years

Cal Advocates' *primary* recommendation to set post-test year revenue increases at 3.0 percent per year based on the CPI³⁶⁰⁶ should be rejected as it provides insufficient funding for PG&E's capital projects and is based on an index that is unrelated to the costs to operate a utility. To illustrate the impact of adopting Cal Advocates' PTYR proposal on PG&E's ability to fund

³⁶⁰⁰ CALPA-04, p. 22, Table 4-5.

³⁶⁰¹ CALPA-16, p. 22, lines 13-19.

³⁶⁰² CALPA-16, p. 22, lines 13-19.

³⁶⁰³ CALPA-16, p. 22, lines 13-19.

³⁶⁰⁴ CALPA-16, p. 22 line 26 to p. 23, line 2. See Fn. 10, PG&E, Cal Advocates, and TURN have reached a settlement on wildfire liability insurance, which if adopted, will resolve PG&E's wildfire insurance forecast and revenue requirement, and will remove PG&E's proposed wildfire insurance attrition adjustment.

³⁶⁰⁵ CALPA-16, p. 19, lines 22-24.

³⁶⁰⁶ CALPA -16, p. 2, line 12 to p. 3, line 11. The 3 percent excludes PG&E's proposed discrete expense adjustments associated with gas storage, the planned closure of the Diablo Canyon Power Plant (DCPP), Time-of-Use (TOU) and Peak-Day Pricing (PDP), and PG&E's proposed bottom-up capital adjustment for DCPP, and gas storage. After adjusting for these items, Cal Advocates' recommended attrition revenue increases are effectively equal to 2.25 percent for 2024, (0.4) percent for 2025, and (1.67) percent for 2026. See CALPA-16, p. 18, Table 16-5.

its operations during the attrition years, PG&E performed a study using PG&E's 2024, 2025 and 2026 proposed capital additions forecast and assumed Cal Advocates' recommended revenue increase for PTY revenues.³⁶⁰⁷ PG&E then calculated the level of funding available for operating expenses for 2024, 2025 and 2026 in nominal dollars under Cal Advocates' proposal. Cal Advocates' proposal would result in operating expense reductions of \$626 million (9.19 percent) in 2024, \$888 million (12.86 percent) in 2025, and \$918 million (13.44 percent) in 2026 compared to PG&E's forecast. Accounting for cost escalation as described in its testimony, PG&E would need to reduce its annual expenses by \$717 million (10.52 percent) in 2024, \$810 million (11.72 percent) in 2025, and \$788 million (11.54 percent) in 2026.³⁶⁰⁸ Adopting Cal Advocates' PTYR proposal and maintaining PG&E's forecast level of capital expenditures would result in a substantial under-funding of PG&E's expense work.

While capital costs are the primary driver of the need for PTYR relief, cost escalation is an important secondary driver.³⁶⁰⁹ PG&E is facing extreme cost escalation related to resources necessary to provide utility service. This includes certain elements of utility costs that have grown at a rate higher than the broad-based inflation in the general economy.³⁶¹⁰ PG&E's September 6, 2022 Update Testimony, is evidence that there was significant inflation in recent years as observed in Q2 2022's IHS Markit escalation rates compared to the Q1 2020's IHS Markit escalation rates that were used in its original application.³⁶¹¹ To allow PG&E a fair opportunity to earn the rate of return found reasonable by this Commission, authorized revenues must be adjusted in the PTY period based on escalation in the cost of goods and services that

³⁶⁰⁷ PG&E-24-E, p. 1-8, lines 4-15; PG&E-24-E, Attachment B includes the results of the study.

³⁶⁰⁸ PG&E-24-E, p. 1-8, lines 4-15.

³⁶⁰⁹ PG&E-11-E, p. 1-9, lines 20-211.

³⁶¹⁰ PG&E-11-E, p. 1-9, lines 25-31.

³⁶¹¹ PG&E-33, Ch. 2.

PG&E purchases, rather than a generic CPI rate that is not indicative of PG&E's actual expected cost escalation.³⁶¹²

To respond to intervenor concerns that a PTYR mechanism should be simple and that intervenors do not have the capacity to review a multi-year capital forecast, PG&E generally based its PTY capital additions forecast for attrition purposes on the TY amount, adjusted only to reflect appropriate cost escalation.³⁶¹³ This allows PG&E to base this component of its recommendation on the test year capital additions forecast, which intervenors have the full opportunity to assess and evaluate. The critical aspect of this approach is applying escalation to the capital additions forecast, and then calculating the resulting revenue requirement, rather than applying escalation directly to the revenue requirement, which, as discussed above, results in substantial under-funding.

The exceptions to PG&E's approach of applying simple escalation adjustments to the capital additions forecast are for gas storage, nuclear generation, hydro generation, corporate real estate and electric distribution system hardening and the community rebuild program for which PG&E proposes that additions for each category be based on PG&E's bottom-up forecast.³⁶¹⁴ These exceptions reflect both increases and decreases in PG&E's PTY capital spending forecasts (as opposed to simple escalation).³⁶¹⁵

For expenses (*e.g.*, labor, materials, and health care costs), PG&E generally recommends adjustments to reflect the *appropriate measures* of escalation. This too is important, because the national CPI bears little relation to PG&E's utility-specific expenses.³⁶¹⁶ Specific exceptions to

³⁶¹² See discussion of CPI in Sections 2.5.4.3.

³⁶¹³ PG&E-11-E, p. 1-13, lines 11-20.

³⁶¹⁴ PG&E-11-E, p. 1-8, lines 4-18.

³⁶¹⁵ PG&E-11-E, p. 3-4, lines 1-27.

³⁶¹⁶ PG&E-11-E, p. 1-15, lines 17-18.

this, where certain operating expenses are not expected to follow a normal pattern of escalation are outlined in PG&E's testimony.³⁶¹⁷

11.1.4.2 Use Of A Single Index Is Flawed Whether Based On A CPI Or Results In Other GRCs

As explained above, no single index, including the 3.0 percent CPI-based increase Cal Advocates proposes, can reflect the different drivers of expense and capital cost escalation. The factors that drive capital cost growth is the growth in rate base relative to existing rate base. This in turn depends largely on how capital additions (less depreciation) compares to existing plant and rate base. Whatever results are obtained from the calculation, it would pure happenstance if the results were the same as the CPI or a single index derived from other GRCs.

Cal Advocates compares PG&E's results to those of the other utilities.³⁶¹⁸ The specific percentages adopted for PG&E or other utilities bear no relation to the reasonableness of PG&E's PTYR proposal and forecast in this specific case. PTY revenue requirement growth should be determined based on reasonable estimates of cost-of-service growth based on evidence presented in each case, not on percentage increases adopted in other proceedings that relied on a different set of facts and circumstances.³⁶¹⁹ The past results Cal Advocates references, in fact, demonstrate just how much those different circumstances can be, varying widely from as low as 2.65 percent for Sempra in 2013 to as high as 7.5 percent for SCE as recently as 2020.³⁶²⁰

Further, Cal Advocates continues to compare PG&E results to comprehensive settlements (where tradeoffs between test year increases and PTY period increases may have been made) or the unique circumstances of other GRCs across and different IOUs.³⁶²¹ The Commission

³⁶¹⁷ PG&E-11-E, p. 2-7, line 1 to 2-9, Table 2-2.

³⁶¹⁸ CALPA-16, p. 5, line 9 to p. 7, line 2.

³⁶¹⁹ PG&E-24-E, p. 1-13, lines 1-5.

³⁶²⁰ CALPA-16, p. 5, line 9 to p. 7, line 2.

³⁶²¹ CALPA-16, p. 5, line 9 to p. 7, line 2.

should give these comparisons no weight. First, the PTY increases in PG&E's 2011 GRC (D.11-05-018), PG&E's 2017 GRC (D.17-05-013), PG&E's 2020 GRC (D.20-12-005) and Sempra's 2016 GRC (D.16-06-054) were negotiated as part of an overall settlement of each utility's GRC. In each of these instances, the parties, including Cal Advocates, agreed that the settlements were non-precedential.³⁶²² This is consistent with Commission Rule 12.5, as well as its predecessor Rule 51.8, which states that settlements are not precedential unless the Commission "expressly provides otherwise." Finally, PG&E's 2014 GRC decision explained why Sempra's 2012 GRC and other settlements, whether involving the Sempra utilities or PG&E, should be disregarded as a measure of PG&E's PTY revenue requirements.³⁶²³

While the CPI bears no relation to capital cost increases (as explained above), it also is fundamentally the wrong index to use in projecting gas and electric utility *expense* increases. As described in IHS Global Insight's technical appendix to the Power Planner Publication:

The CPI measures changes in the price of goods and services bought by households. It is based on a sample of prices for food, clothing, shelter, fuels and transportation, medical services, and other goods and services that people buy for day-to-day living. Price change is measured by pricing essentially the same market basket ... in a selected base period.³⁶²⁴

The Bureau of Labor Statistics reports that major groups and examples in the basket of goods and service which comprise the CPI are:

FOOD AND BEVERAGES (breakfast cereal, milk, coffee, chicken, wine, full service meals, snacks); HOUSING (rent of primary residence, owners' equivalent rent, fuel oil, bedroom furniture); APPAREL (men's shirts and sweaters, women's dresses, jewelry); TRANSPORTATION (new vehicles, airline fares, gasoline, motor vehicle insurance); MEDICAL CARE (prescription drugs and medical supplies, physicians' services, eyeglasses and eye care, hospital services); RECREATION (televisions, toys, pets and pet products, sports equipment, admissions); EDUCATION AND COMMUNICATION (college tuition, postage, telephone services, computer software and accessories); OTHER GOODS AND

³⁶²² PG&E-24-E, Attachment A provides specific references to these settlement agreements.

³⁶²³ D.14-08-032, p. 660, fn. 165.

³⁶²⁴ PG&E-11-E, p. 1-15, lines 19-25.

SERVICES (tobacco and smoking products, haircuts and other personal services, funeral expenses).³⁶²⁵

As the description shows, the CPI is tracking what households are purchasing for day-to-day living. Households are not purchasing steel cable, electronic switching equipment, and jackhammers for day-to-day living, nor is PG&E buying breakfast cereal or purchasing children's toys. The Commission summarized the inherent shortcoming of the CPI in estimating utility expenses in SCE's 2003 GRC decision:

The CPI may be a simple, accessible measure of general inflation faced by urban U.S. consumers, but that alone does not make it appropriate as a measure of price changes faced by an electric utility. It does not specifically cover the prices of the typical goods SCE purchases. Conversely, SCE's proposed escalation rates were not designed to track the general level of inflation, and there is no reason why they should do so.³⁶²⁶

Most recently in D.19-09-051, the Commission found that applying a percentage increase based on the CPI does not reflect how utilities incur costs because it is a broad wholesale pricing index which reflects price increases for goods and services in general and does not sufficiently capture the operations and maintenance escalation inputs of SDG&E and SoCalGas. The Commission found "that Global Insight escalation rates are specific to the utility industry and more accurately reflects SDG&E and SoCalGas' inflationary cost increases"³⁶²⁷

The Commission should also recognize the CPI is a *price* index and not a *total cost* index.³⁶²⁸ The costs established in this GRC by way of a revenue requirement are fixed by the test year RO and PTYR mechanism (whether expense or capital). Unlike energy costs, they do not change when there is increased sales volume. If PG&E were able to grow revenues by increasing sales, an inflationary price-based index might become more feasible, at least as to expenses, because the needed revenue requirement would be covered by the inflationary increase

³⁶²⁵ PG&E-11-E, p. 1-15, line 28 to p. 1-16, line 6.

³⁶²⁶ D.04-07-022, p. 278.

³⁶²⁷ D.19-09-051, p. 708.

³⁶²⁸ PG&E-11-E, p. 1-17, line 3.

as well as by the percentage increase in sales.³⁶²⁹ However, by discouraging energy usage and adopting a sales balancing account, California does not permit PG&E to increase revenues by increasing sales during the PTY period. As a result, the only way for the Company to change its revenue between GRCs is through an adjustment to base revenue requirements (*i.e.*, PTY attrition increases) and that adjustment should be designed to reflect reasonable expectations for changes in utility costs, not CPI.³⁶³⁰

11.1.4.3 The Commission Should Not Adopt Cal Advocates' Recommendations That Provide No PTYR Adjustments For Specific PG&E Programs

Cal Advocates proposes no attrition adjustments for a number of PG&E programs.

PG&E responds to these recommendations in other sections of the brief as follows:

- Based on recommendations contained in Exhibit CALPA-04 (Electric Distribution Expenses), Cal Advocates proposes a TY expense level of \$924.084 million for vegetation management costs³⁶³¹ with no adjustments during attrition years. Cal Advocates' recommendation should not be adopted for the reasons discussed in Section 4.9 above.
- Cal Advocates addresses a number of PG&E TY 2023 forecasts in various exhibits as follows: Human Resources, Shared Services and IT, and Companywide A&G costs.³⁶³² PG&E responds to those TY recommendations in Sections 8, 7, and 9 of the brief, respectively. With respect to PTYR, Cal Advocates states that consistent with those recommendations, Cal Advocates does not propose attrition adjustments during PTYs for employee or other A&G items.³⁶³³ Cal Advocates' testimony on PG&E's various 2023 TY forecasts do not address PTY adjustments or refute that these business costs are subject to escalation beyond the TY. As such, the Commission should not adopt these recommendations. All of these costs

³⁶²⁹ PG&E-11-E, p., 1-17, lines 14-17.

³⁶³⁰ PG&E-11-E, p. 1-17, lines 18-26.

³⁶³¹ CALPA-16, p. 21, lines 3-8.

³⁶³² CALPA-16, p. 22, lines 13-19.

³⁶³³ CALPA-16, p. 22, lines 17-19.

should be subject to escalation and should adopt PG&E's specific PTY adjustments included in PG&E's opening testimony.³⁶³⁴

- Cal Advocates proposes no PTY adjustment for wildfire liability insurance.³⁶³⁵ PG&E, TURN and Cal Advocates have reached a settlement on wildfire liability insurance that resolves the forecast and withdraws PG&E's proposed attrition adjustment for this item.³⁶³⁶
- Cal Advocates has not addressed the subject of PTY adjustments for the EPSS program. The Commission should adopt PG&E's proposed specific expense adjustments for EPSS during the PTYs.³⁶³⁷

11.1.4.4 The Commission Should Not Adopt Cal Advocates' Alternative Recommendation For 2 Percent O&M Cost Reductions In The PTYs.

Cal Advocates recommends that in the event the Commission does not adopt Cal Advocates' primary proposal, then the Commission should recognize a 2 percent annual O&M cost reductions in the PTYs.³⁶³⁸ The Commission should not adopt this proposal.

The 2 percent O&M cost reduction is an aspirational target that includes costs outside of the GRC.³⁶³⁹ Conversely, cost escalation is an immutable cost driver that will undoubtedly create expense pressure, particularly given current inflation levels. Additionally, PG&E's PTYR proposal already includes O&M cost reductions that will contribute to the 2 percent goal such as reductions to vegetation management expense and O&M reductions from the DCPD closure.³⁶⁴⁰

³⁶³⁴ PG&E-07, Ch. 1A; PG&E-08 Chs. 4 and 5; PG&E-09, Ch. 9; and PG&E-11, Ch. 2.

³⁶³⁵ CALPA-16, p. 22, line 26 to p. 23, line 2.

³⁶³⁶ See Section 9.3.2.2.1; *Joint Motion of Pacific Gas and Electric Company, The Utility Reform Network and The Public Advocates Office at the California Public Utilities Commission for Expedited Approval and Adoption of the Attached Settlement Agreement on Insurance Related Issues* (Joint Motion for Adoption of Insurance Settlement) (October 7, 2022).

³⁶³⁷ PG&E-04, Ch. 4.6.

³⁶³⁸ CALPA-16, p. 19, lines 22-24.

³⁶³⁹ PG&E-24-E, p. 1-15, lines 7-9.

³⁶⁴⁰ PG&E-11-E, p. 2-9, Table 2-2.

Any further reductions to PG&E’s O&M expenses would underfund PG&E’s operations during PTYs.³⁶⁴¹

11.1.5 TURN’s Proposals Should Be Rejected

11.1.5.1 The Commission Should Not Adopt TURN’s Recommendations For A PTYR Mechanism That Incorporates Escalation Based On CPI And A 7-Year Average Methodology To Forecast Capital Additions

TURN’s primary proposal “recommends using a two-part PTY mechanism”³⁶⁴² that escalates TY expenses by CPI³⁶⁴³ and estimates PTY capital revenue requirement growth in two categories: (i) Category 1, which includes capital additions related to electric distribution wildfire mitigations, DCPD and gas storage based on specific capital expenditure recommendations; and (ii) Category 2, which includes capital additions for all other cost categories using a 7-year historical average (2015-2021) of capital additions escalated using the IHS Markit index.³⁶⁴⁴ TURN’s alternative proposal recommends an attrition mechanism that escalates test-year expenses by CPI plus 50 basis points.³⁶⁴⁵

For the reasons discussed below, PG&E urges the Commission to adopt attrition year capital addition spending forecasts (other than for gas storage, nuclear and hydro generation, corporate real estate and electric distribution system hardening and the community rebuild program, for which PG&E proposes to use bottom-up forecasts), using the *test year* capital

³⁶⁴¹ PG&E-24-E, p. 1-15, lines 10-14.

³⁶⁴² TURN-20, p. 10, lines 4-6.

³⁶⁴³ TURN-20, p. 10, lines 11-13.

³⁶⁴⁴ TURN-20, p. 12, lines 3-21.

³⁶⁴⁵ TURN-20, p. 11, lines 8-9.

additions forecast escalated. The escalation should be based on IHS Markit escalation rates as updated in PG&E's Update Testimony.³⁶⁴⁶

11.1.5.2 The Commission Should Not Adopt TURN's Primary Proposal To Escalate Capital Additions Based On A 7-Year Average.

TURN's *primary* proposal would compute PTY capital cost growth for each Category 2 plant as defined by TURN based on escalated 7-year (2015-2021) average level of capital additions proposal using capital escalation rates from IHS Markit.³⁶⁴⁷

Thus, from a PTYR controversy perspective involving capital, one of the principle differences between the PG&E proposal and TURN's primary proposal relates to whether to use PG&E's recommendation to use the test year forecast escalated or whether the forecast should be reduced to an escalated seven-year average. As discussed below: (1) using a 7-year average would significantly underfund PG&E's operations and does not account for the significant capital investment PG&E forecasts for the 2023 GRC period; and (2) using a 7-year average is inconsistent with most of the recent Commission precedent on the issue.

11.1.5.3 Using a 7-year Average Would Significantly Underfund PG&E's Operations And Fails To Account For The Significant Capital Investment PG&E Forecasts For The 2023 GRC Period

The 7-year historical average approach recommended by TURN would significantly underfund PG&E's capital programs during the PTYs.³⁶⁴⁸ Estimating future capital additions based solely on past spending ignores the context of present-day challenges and circumstances that may have changed over time. Such approach would be a poor policy choice given PG&E's expanded need to replace aging infrastructure and address safety issues and risk mitigation,

³⁶⁴⁶ PG&E-11-E, p. 1-7, line 34 to p. 1-8, line 3; see e.g., D.19-09-051, p. 708 (where the Commission found for example that "Global Insight escalation rates are specific to the utility industry and more accurately reflects SDG&E and SoCalGas' inflationary cost increases.") See PG&E-33C, p. 2-2, Table 2-1 for the updated Q2 IHS non-labor escalation factors.

³⁶⁴⁷ TURN-20, p. 12, lines 3-21.

³⁶⁴⁸ PG&E-24-E, p. 1-19, lines 22-23.

which has led to recorded capital investment levels that are much higher than the 7-year average.³⁶⁴⁹ This is demonstrated in Table 11-3 below:³⁶⁵⁰

TABLE 11-3
SEVEN-YEAR AVERAGE ANALYSIS OF RECORDED GROSS ADDITIONS
(MILLIONS OF DOLLARS^(a))

Line No.	Year	Recorded Additions ^(b)	7-Year Average	Variance		Year	Recorded Additions ^(b)	7-Year Average	Variance	
				Dollars	Percent				Dollars	Percent
1	2011	\$4,000				2014	\$4,219			
2	2012	4,540				2015	4,932			
3	2013	5,172				2016	4,969			
4	2014	4,219				2017	5,135			
5	2015	4,932				2018	5,499			
6	2016	4,969				2019	5,689			
7	2017	5,135				2020	6,003			
8	2018	\$5,499	\$4,710	\$(789)	-14%	2021	\$6,254	\$5,207	\$(1,047)	-17%

(a) All dollar amounts escalated to 2023 dollars for comparison.
(b) Source: PG&E's Power Plan financial system.

Even after escalating to 2023 dollars for comparison, the 7-year average of 2011-2017 is lower than the 2018 recorded additions by 14 percent (\$789 million).³⁶⁵¹ Using a more recent 7-year average of 2014-2020, that variance grows to 17 percent (\$1,047 million) lower than the recorded 2021 additions.³⁶⁵² PG&E's capital investment to provide safe and reliable service are increasing at a significant pace primarily due to the increase in wildfire mitigation and other risk mitigation work. A 7-year average will necessarily underestimate the PTY capital needs.

TURN proposes to use a 7-year average (2015-2021) for PTY capital attrition excluding wildfire mitigation capital expenditures, DCP and gas storage (Category 2 as defined by

³⁶⁴⁹ PG&E-24-E, p. 1-19, lines 24-29.

³⁶⁵⁰ PG&E-24-E, p. 1-19, lines 29-30 and p. 1-20, Table 1-2.

³⁶⁵¹ PG&E-24-E, p. 1-20, lines 1-3.

³⁶⁵² PG&E-24-E, p. 1-20, lines 3-5.

TURN).³⁶⁵³ As summarized in Table 11-4 below, in comparison to TY estimates prepared by PG&E's subject matter experts (adjusted for escalation), the 7-year average proposed by TURN would underfund PG&E's capital programs by \$768 million in 2024, \$916 million in 2025, and \$1,226 million in 2026.

TABLE 11-4
COMPARISON OF PG&E AND TURN'S CATEGORY 2 PROPOSED CAPITAL ADDITIONS
ATTRITION
(MILLIONS OF NOMINAL DOLLARS)

Line No.	Description	2024 Gross Additions			2025 Gross Additions			2026 Gross Additions		
		PG&E ^(a)	TURN ^(b)	Variance	PG&E ^(a)	TURN ^(b)	Variance	PG&E ^(a)	TURN ^(b)	Variance
1	Capital Additions	\$5,888	\$5,120	\$(768)	\$6,178	\$5,261	\$(916)	\$6,635	\$5,410	\$(1,226)
Notes: Proposed attrition capital additions reflect Category 2 spending proposed by TURN which includes total company additions, excluding wildfire mitigation, DCPD and gas storage. (a) Source: PG&E RO Model dated Feb 28, 2022 (b) Source: TURN-20 Cap Adds Attrition WP 6-2-22										

TURN does not address the consequences of these attrition year capital expenditure reductions in its testimony. For the reasons discussed above, TURN's proposal would significantly underfund PG&E's operations and should not be adopted.

³⁶⁵³ TURN-20, p. 10, lines 11-13; p. 12, lines 3-15.

11.1.5.4 Using a 7-year Average Is Not Consistent With The Majority Of Recent Precedent On The Issue.

As to the difference between using a seven-year average or a test year forecast escalated, the Commission precedent on this issue has been mixed over the last two decades.³⁶⁵⁴ While TURN references two examples where a 7-year average was chosen, PG&E's 2014 GRC decision and SDG&E's 2019 GRC, those do not reflect the majority of decisions over the last twenty years.

TURN acknowledges that the Commission in recent decisions approved an escalation of TY spending³⁶⁵⁵ but argues that the Commission should instead return to a now-disproved approach used in the 1980s and early 1990s.³⁶⁵⁶ TURN's testimony includes Figure 1 showing net electric plant additions as a percentage of electric plant in service and asserts that, excluding years where the nuclear plants were brought online or retired, the level of plant additions during much of the last decade is not materially different than the level of increases experienced during the 1980s.³⁶⁵⁷ The use of net additions as a percentage of plant for comparison of spending level over time as TURN does is inappropriate. Even a significant increase in net additions will result in the same or lower percentage factor as the cumulative plant base or the denominator

³⁶⁵⁴ Decisions with a 7-year average: D.14-08-032 (PG&E's 2014 GRC), p. 656 and, D.19-09-051 (Semptra's 2019 GRC), pp. 708-709. Decisions escalating test year capital additions or use of other methods such as budget based: D.04-07-022 (SCE's 2003 GRC), p. 279, D.06-05-016 (SCE's 2006 GRC), p. 4, D.12-11-051 (SCE's 2012 GRC, p. 608, D.15-11-021 (SCE's 2015 GRC), p. 391; and D.19-05-020 (SCE's 2018 GRC), p. 285. In D.21-08-036 (SCE's 2021 GRC), the Commission adopted a budget-based forecast for wildfire mitigation capital additions (p. 547) and zero escalation of non-wildfire related capital additions with the exception of the Residential and Commercial New Service Connection forecasts in the attrition years in order to help mitigate the impacts of large wildfire capital additions in the post-test years, and given the uncertainty in SCE's actual spending in these years and the economic uncertainty facing ratepayers due to the COVID-19 pandemic (pp. 548-550).

³⁶⁵⁵ TURN-20, p. 6, lines 11-16.

³⁶⁵⁶ TURN-20, p. 7, lines 17-19.

³⁶⁵⁷ TURN-20, p. 7, lines 1-19.

amount grows.³⁶⁵⁸ To illustrate, PG&E's 2012 net electric additions of \$3.7 billion was 9.7 percent of its 2012 electric plant balance, whereas in 2018, PG&E's net electric additions of \$4.1 billion (\$400 million higher than 2012) was *only* 7 percent (2.5 percent lower than 2012) of its 2018 electric plant balance.³⁶⁵⁹ Additionally, TURN's analysis does not address PG&E's Gas business in which PG&E has invested heavily in capital infrastructure in the last decade compared to the 1980-1990s.³⁶⁶⁰ Finally, even if one takes TURN's Figure 1 at face value, which PG&E does not agree would be appropriate for the reasons described above, the average percentage of PG&E's electric net additions to electric plant from 1980-2009 is 4.3 percent.³⁶⁶¹ The average from 2010-2020 jumps up to 6.6 percent. The Figure illustrates again that annual additions have increased significantly over the last decade, as shown earlier in Table 11-3.

The Commission should apply a reasonable escalation approach to forecast PG&E's PTYR spending—one that generally would use the test year as the best proxy for forecasting PTYR additions. As an analytical approach, when the Commission adopts a seven-year average of real capital spending in a given area it suggests the Commission believes the capital spending to be level (in real terms) over time, rather than using the test year forecast as the best indicator. On the other hand, when the Commission adopts the test year forecast, escalated for the PTY period, the Commission is essentially recognizing that an averaging approach (even in real terms) is insufficient for a particular program. As discussed above, PG&E's capital investment to provide safe and reliable service are increasing at a significant pace primarily due to the

³⁶⁵⁸ PG&E-24-E, p. 1-21, line 17 to p. 1-22, line 1.

³⁶⁵⁹ PG&E-24-E, p. 1-22, lines 1-5.

³⁶⁶⁰ PG&E-24-E, p. 1-22, lines 5-7.

³⁶⁶¹ TURN-20-Atch1C, Attachment A, pp. A-5-1 to A-5-8, WP 1980-2020 History of PG&E – SCE Plant Additions (Excludes years 1984-1986, 1999 due to major additions and retirements.)

increase in wildfire mitigation and other risk mitigation work.³⁶⁶² Programs associated with these initiatives should be escalated based on most recent estimates, rather than using a historical average that reflects spending patterns before these events. Also as discussed above, the 7-year average proposed by TURN would underfund PG&E's capital programs by \$768 million in 2024, \$916 million in 2025, and \$1,226 million in 2026. To reduce PG&E's 2024 to 2026 capital spending to the levels that preceded current investments in utility safety and reliability efforts would underfund safety efforts.

11.1.5.5 The Commission Should Not Adopt TURN's Alternative Recommendation To Escalate Capital Costs By CPI Plus 50 Basis Points

For the reasons discussed in response to Cal Advocates' recommendation, the fundamental problem with the use of CPI to establish utility rates is that the CPI does not measure increases in utility costs, the cost of labor, or wage growth and is not specific to California. Adding an arbitrary 50 basis points to the CPI does not make the index indicative of increases in utility costs. Additionally, while the PTYR mechanism adopted in Sempra's 2012 GRC escalated the entire revenue requirement by CPI plus 75 basis points, that was clearly distinguished by the Commission in PG&E's 2014 GRC and was based on the unique facts presented in Sempra's testimony in that proceeding.³⁶⁶³

Second, TURN argues against the use of indices designed specifically to capture changes in utility costs, stating that, "if the indices are fashioned too narrowly, the attrition simply becomes a self-fulfilling prophecy where the more the utility expends, the more will be passed along in the future"³⁶⁶⁴ thereby reducing pressure on the utility to be efficient. To the contrary, under California's forecast TY ratemaking approach, PG&E's shareholders bear the risks and opportunity of cost variances during the rate case cycle, giving management every incentive to

³⁶⁶² PG&E-24-E, p. 1-20, lines 5-8.

³⁶⁶³ PG&E-24-E, p. 1-17, line 28 to p. 1-18, line 2.

³⁶⁶⁴ TURN-20, p. 4, line 23 to p. 5, line 2.

manage its costs regardless of the attrition outcome.³⁶⁶⁵ Additionally, PG&E’s proposal already does require the utility to find efficiencies in PTY to absorb cost increases beyond escalation. Escalation factors capture the higher unit cost of resources due to inflation but do nothing to capture cost pressure driven by the need to complete additional units of work. The ongoing cost of serving new customers is not captured anywhere in PG&E’s attrition proposal.³⁶⁶⁶ TURN recognizes that customer growth impacts capital costs and adjusts for changes in new customers in their proposed capital escalation rate. The same pressures exist on the expense side.³⁶⁶⁷ Additionally, there are other cost pressures such as changes in government laws and regulations that can increase costs beyond normal escalation. These are not captured in PG&E’s PTY forecasts and therefore must be offset by productivity gains in order for PG&E to earn its authorized rate of return.³⁶⁶⁸

For the foregoing reasons, the Commission should not adopt TURN’s recommendation for a PTYR escalation factor based on CPI.

11.2 Z-Factor Memorandum Account

PG&E proposes to continue the Z-factor mechanism with a modification to update test year and post-test year and PTY revenue requirement adjustments through an advice letter (AL) process. Cal Advocates recommends that the Z-factor should not apply to test year costs.³⁶⁶⁹ TURN recommends that PG&E should be required to file an application to seek recovery of Z-factor costs.³⁶⁷⁰ For the reasons discussed below, the Commission should not adopt Cal Advocates’ and TURN’s recommendations.

³⁶⁶⁵ PG&E-24-E, p. 1-17, lines 7-11.

³⁶⁶⁶ PG&E-24-E, p. 1-17, lines 11-17.

³⁶⁶⁷ TURN-20, p. 13, lines 15-20.

³⁶⁶⁸ PG&E-24-E, p. 1-17, lines 19-23.

³⁶⁶⁹ CALPA-16, p. 23, lines 20-22.

³⁶⁷⁰ TURN-13, p. 27, line 11 to p. 28, line 3.

11.2.1 Z-Factor Adjustments Should Apply To The Test Year

PG&E's current Z-Factor, as adopted in PG&E's 2020 GRC settlement, authorizes tracking of costs for the TY and PTY. Cal Advocates agrees with the continuation of the Z-factor mechanism but recommends "that the mechanism be effective only during the [PTY], and not for the [TY]. Exogenous events that could qualify as a Z-factor are just as likely to occur in the test year as during the attrition year. There is no sound policy reason for not allowing the Z-factor to occur in the test year.

Cal Advocates states that they were "unaware of any litigated GRC where a Commission decision has granted [TY] Z-factor adjustments to a major California energy utility" The Commission had authorized Z-factor adjustments for the TY as well as the PTYs in Sempra's 2019 GRC in which it found:

With respect to ORA's proposal, we find that a Z-Factor event is just as likely to occur during the TY as it does during the attrition years. A key element in a Z-Factor event is that the event is unpredictable and occurs after base rates have been set and there is nothing that differentiates the TY from the attrition years insofar as the possible occurrence of a Z-Factor event. ORA does not specify in these applications why it recommends the exclusion of the TY other than stating that this is consistent with their request in PG&E's TY2014 and TY2017 GRCs both of which were resolved by adopting settlement agreements from parties. Therefore, absent any rationale to exclude a Z-Factor event that may occur during Applicants' TYs, we find it reasonable to reject ORA's proposal and conclude that the Z-Factor mechanism should be applicable to the TY2019 as well as attrition years 2020 and 2021.³⁶⁷¹

The same rationale applies to PG&E.

11.2.2 The Commission Should Permit PG&E To Seek Recovery Of Z-Factor Costs Via Advice Letter Filing

TURN opposes PG&E's proposal to request recovery of any recorded balances in the Z-Factor Memorandum Account (ZFMA) through an advice letter instead of an application. Seeking recovery of such costs via advice letter is consistent with the process that the Commission approved for SCE in its most recent GRC. The Commission should approve the same process for PG&E.

³⁶⁷¹ D.19-09-051, p. 712

12. GENERAL REPORT (EXHIBIT PG&E-12)

12.1 Escalation Rates

On March 20, 2022, PG&E filed an Amended Application that provided updates to our Wildfire Mitigation Plan forecasts (Amended Application). The Amended Application requested a TY 2023 revenue requirement of \$3.125 billion over adopted 2022 revenue requirements.³⁶⁷² PG&E's revenue requirement calculation used estimated escalation rates for PG&E's Operating Units (Labor); PG&E administrative and General expenses (Labor); medical escalation and non-labor operations and maintenance (O&M) for electric distribution, electric transmission, nuclear generation, hydro generation, fossil generation, gas distribution, gas transmission, and gas storage.³⁶⁷³ PG&E stated in its March 2022 filing that it may update its forecast escalation rates as allowed by the CPUC Rate Case Plan.³⁶⁷⁴

On September 6, 2022 PG&E served Update Testimony updating the revenue requirement for PG&E's 2023 GRC based on changes to the escalation factors that PG&E used in its Amended Application and due to federal tax changes and updates.³⁶⁷⁵ The CPUC's Rate Case Plan allows utilities to file update testimony for: known changes in cost of labor based on contract negotiations completed since the tender of Notice of Intent or known changes that results from updated data using the same indexes used in the original presentation during hearings; changes in non-labor escalation factors based on the same indices the party used in its original presentation during hearings; and for known changes due to governmental action such as changes in tax rates, postage rates, or assessed valuation.³⁶⁷⁶

³⁶⁷² PG&E-64, p. 4-3, Table 4A-1, line 5, Column C.

³⁶⁷³ PG&E-12, p. 3-2, lines 8-12.

³⁶⁷⁴ PG&E-12, p. 3-1, lines 14-19.

³⁶⁷⁵ PG&E-33, p. 2-1, lines 13-17.

³⁶⁷⁶ D.07-07-004, p. A-36; see also D.21-08-036, p. 180.

PG&E requests that the updated expense non-labor escalation rates and capital escalation rates be accepted as reasonable forecasts and be adopted by the CPUC for use in determining PG&E's 2023 revenue requirement and post-test year adjustments. PG&E does not propose changes to its operations and maintenance expense labor escalation factors.³⁶⁷⁷

As a result of changes in escalation rates and tax changes, PG&E's revenue requirement increase for its Test Year changed from \$3.125 billion to \$3.967 billion.³⁶⁷⁸ PG&E's revenue requirement request for the attrition years increased from \$1.018 billion to \$1.067 billion in 2024, from \$755.276 million to \$850.320 million in 2025, and from \$561.067 million to \$667.922 million in 2026.³⁶⁷⁹

12.2 Compliance With Prior Commission Decisions

In the 2023 GRC, PG&E was required to comply with 86 individual items from legislation and/or prior decision issues by the CPUC.³⁶⁸⁰ PG&E demonstrated its compliance with each requirement in its opening testimony and workpapers and summarized the action required, a reference to the requirement, and the compliance item in a Reporting and Compliance Items table.³⁶⁸¹ For example, the SmartMeter Opt-Out Phase 2 Decision requires PG&E to: (1) provide a summary of costs incurred and revenues collected associated with providing the Opt-Out service option; and (2) identify the portion of revenue that was over or under collected for a subsequent allocation or refunds that will be made to the residential customer class.³⁶⁸² To

³⁶⁷⁷ PG&E-33, p. 1-1, lines 16-18. PG&E's proposed O&M non-labor escalation rates are provided in PG&E-33, p. 2-2, Table 2-1 CONF and proposed capital escalation rates are provided on p. 2-3, Table 2-3 CONF.

³⁶⁷⁸ PG&E-64, p. 4-3, Table 4A-1, line 5, Column C and Column E.

³⁶⁷⁹ PG&E-64, p. 4-52, Table 4F-1.

³⁶⁸⁰ PG&E-12, p. 6-1, lines 5-31.

³⁶⁸¹ PG&E-12, p. 6-2 to p. 6-13, Table 6-1.

³⁶⁸² D.14-12-078, p. 79, Ordering Paragraph (OP) 6. This requirement is listed on PG&E-12, p. 6-4, Table 6-1, Reporting and Compliance Items, line 18.

comply with this requirement PG&E provided a summary of recorded Opt-Out costs and billed revenues associated with the SmartMeter Opt-Out Program.³⁶⁸³

PG&E seeks approval to discontinue one reporting requirement because it is no longer necessary.³⁶⁸⁴ In D.15-04-024, San Bruno Explosion and Fire Order Instituting Rulemaking (OIR), PG&E was ordered to submit a detailed accounting to the CPUC and other parties of all entries to the Shareholder-Funded Gas Transmission Safety Account (SFGTSA) as an information only filing. When PG&E's spending obligations have been exhausted, PG&E is required to submit a final accounting to the Commission and other parties within 180 days of the date when the Shareholder-Funded Account was exhausted.

In 2016, the Commission issued D.16-12-010, which finalized the ratemaking treatment of the \$850 million (safety-spend) penalty assessed in D.15-04-024 related to gas pipeline safety enhancements. The decision also approved a list of safety programs and required PG&E to track these expenditures in the SFGTSA. For years 2015 to 2018, PG&E achieved safety spending on all capital programs except for six, where PG&E had collectively spent approximately \$30 million less than the amounts allocated to those programs. PG&E proposes to record \$30 million towards the Inoperable and Hard to Operate Valves program³⁶⁸⁵ and proposes to eliminate the associated report of account activity required by the Commission. The Inoperable and Hard to Operate Valves program is an approved safety capital program which PG&E had invested above the authorized amount.

By recording \$30 million towards the Inoperable and Hard to Operate Valves program PG&E has satisfied its required safety-spend capital penalty and proposes to eliminate the associated report of account activity. PG&E plans to work with the CPUC to hire an independent auditor to audit the amounts recorded into the SFGTSA. Upon receiving the

³⁶⁸³ PG&E-06-E, p. 7-12, lines 15-27 and p. 7-14, Tables 7-1 and 7-2.

³⁶⁸⁴ See Appendix B, Uncontested Non-Forecast Items, line 20.

³⁶⁸⁵ PG&E describes this program in PG&E-03, Chapter (Ch.) 5.

CPUC’s decision on PG&E’s proposal to satisfy the remaining \$30 million obligation, PG&E will work with the independent auditor to finalize the audit and will file an advice letter to close out this account.³⁶⁸⁶

12.3 Balancing Accounts And Memorandum Accounts

Under general ratemaking principles, the Commission allows a utility to file a GRC application to recover in base rates a forecast of its operating costs to provide customers safe, reliable, and affordable service.³⁶⁸⁷ The Commission adopts a test year forecast based on the best information available at the time of the application about expected future events and historical trends. By using a prospective forecast methodology, PG&E has an opportunity to recover its costs and earn a return (profit) on its investment in plant in service. PG&E exercises its discretion to ensure optimal safety and reliability of its operations and adapt as necessary to differences between the forecast and actual events.³⁶⁸⁸ PG&E’s actual spending for certain programs will vary from the adopted forecast as PG&E adjusts its spending to most effectively mitigate the risks to its electric and gas systems as circumstances change.

Balancing and memorandum accounts require that amounts be tracked and used only for the designated program and restrict PG&E’s ability to reallocate funds among programs as circumstances change. Excessive use of balancing and memorandum accounts interferes with general ratemaking principles of providing flexibility to shift funds as needs change during a GRC funding cycle. Below, we provide a brief summary of the key principles underlying balancing accounts and memorandum accounts.

Balancing accounts are established by the Commission to record amounts adopted for recovery from customers. Balancing accounts used to recover PG&E’s adopted GRC revenue

³⁶⁸⁶ See PG&E-10, Ch. 15 for additional information.

³⁶⁸⁷ See, e.g., D.18-06-029, p. 13, referencing D.03-05-076, stating “It is a well-established tenet of the Commission that ratemaking is done on a prospective basis.”

³⁶⁸⁸ D.07-07-041, p. 3, Section 2.1 General Ratemaking.

requirements are called Revenue Adjustment Mechanisms (RAMs), which are two-way balancing accounts decoupling revenues to ensure customers do not pay more than they should.³⁶⁸⁹ In many instances, the Commission adds a second step to the recovery process by requiring the adopted amounts recovered from customers through RAMs be trued-up to what is actually spent on a program, sometimes with restrictions.

California utilities' revenues are "decoupled" and RAMs are the ratemaking mechanisms used to implement revenue decoupling. Decoupling breaks the link between revenues collected for providing service and the revenues billed for the energy a utility delivers to its customers, which are driven by factors such as customer growth, weather, including winter storms causing power outages, and economic conditions outside of a utilities' control.³⁶⁹⁰ The adopted revenues/revenue requirement used to set rates always differs from actual revenue billed to customers due to fluctuations in sales. Decoupling ensures PG&E's adopted revenues/revenue requirement is recovered from customers over time regardless of actual sales. RAMs are two-way balancing accounts that track the difference between adopted revenues/revenue requirements and billed revenues. Billed revenues higher or lower than PG&E's adopted revenue requirements are refunded to or collected from customers in the following year, respectively.³⁶⁹¹ Many RAMs are necessary to recover PG&E's functional GRC revenue requirements (electric distribution, gas distribution, electric generation, gas transmission and storage) because the Commission has adopted various allocation methodologies among customer classes for recovering the revenue requirements from customers.

³⁶⁸⁹ RAMs record PG&E's adopted revenue requirements compared to billed revenues and ensure customers only pay amounts equal to its adopted revenue requirements, no more and no less.

³⁶⁹⁰ Breaking the revenue-sales link streamlines the regulatory process for rate adjustments since the sales forecast has no economic impact on revenues, thereby eliminating any incentive to game forecasts of electricity sales.

³⁶⁹¹ See PG&E-12, p. 7-2, footnote (fn.) 2, that lists the RAM accounts in which PG&E's GRC adopted revenue requirements are recovered.

All of PG&E's other GRC-related balancing accounts were established to true-up adopted funding recovered in RAMs to actual spending for various programs. Two-way balancing accounts are established for programs in which PG&E may spend more than the adopted funding for the program. These accounts track differences between PG&E's adopted revenue requirements and actual spending for the program. The balances in these accounts are true-up to actual spending. Unspent funding is returned to customers and spending above the adopted amount is recovered from customers by transferring the balance to the applicable RAM for true-up in rates.

Two-way balancing accounts are appropriate for programs in which a forecast can be developed but actual spending is highly volatile or difficult to estimate due to factors beyond PG&E's control and the costs are material. These types of accounts effectively deal with the uncertainty of the timing and amounts of spending, ensure customers pay only the cost that PG&E actually incurs, and provides cash flows required to support PG&E's debt. Costs recorded to these types of balancing accounts are subject to audit and in certain accounts, costs incurred above established spending thresholds are subject to a demonstration of incrementality or reasonableness for many of these accounts.

One-way balancing accounts limit actual spending for a program to the adopted funding. If PG&E spends less than the adopted amount, the difference is returned to customers by transferring the balance in the account to the applicable RAM. Any costs incurred over the adopted amount cannot be recovered from customers. One-way balancing accounts are typically used for mandated programs funded outside of a GRC such as public purpose programs (e.g., energy efficiency and low income programs) when regulators wish to earmark funds for a specific purpose and for programs where the utility has the ability to control its spending.

Balancing accounts should not be used to recover routine, ongoing costs of operations where there are limited factors beyond a utilities control that can impact the forecast and the costs associated with the program are not material. Balancing accounts are not intended to serve

as oversight of program activities. PG&E's revenue requirements are subject to extensive compliance and reporting requirements to verify that adopted revenues are used in a manner authorized by the Commission. For example, in compliance with D. 19-04-020, PG&E files annual Risk Spending Accountability Reports with the Commission. This compliance report details actual expense and capital expenditures compared to imputed adopted costs derived from the Commission's decision on PG&E's 2020 GRC. This reporting is a better vehicle for reviewing, analyzing, and providing insight to PG&E's activities and spending rather than extensive use of unnecessary balancing accounts.

On the other hand, memorandum accounts are used to track and record incremental costs related to a particular program since funding for the program was not included in an adopted revenue requirement.

It is an established tenet of the Commission that ratemaking is done on a prospective basis. Memorandum accounts are established to track actual costs arising from events that are not reasonably foreseen or for which a reasonable forecast cannot be developed before the costs are incurred. Generally, the Commission has found that memorandum accounts are appropriate if the costs are not forecastable as part of a general rate case, the costs are not substantial, or the existence of the costs is speculative.³⁶⁹² Tracking costs in a memorandum account gives the utility an opportunity to seek recovery of the costs later through an application at the Commission. The Commission's practice is not to authorize increased utility rates to account for previously incurred expenses, unless, before the utility incurs those expenses, the Commission has authorized the utility to record those expenses into a memorandum account for possible future recovery in rates. This practice is necessary to comply with the rule against retroactive ratemaking. The Commission should approve the recording of actual costs to memorandum

³⁶⁹² D.18-06-029, p. 7.

accounts for programs with costs that cannot be reasonably forecast due to timing or significant uncertainties that render a forecast unreliable only under limited circumstances.

PG&E believes excessive use of memorandum accounts and cost recovery deferrals is poor policy that ultimately increases costs for customers. Excessive use of memorandum accounts without current rate recovery also diminishes a utility's financial health by deferring the cash collections needed to service the debt used to finance those assets recorded in the memorandum accounts. If the utility's financial health unduly worsens, its credit ratings will be lowered, and its cost of capital will increase. As a corollary, customer rates would increase to reflect the higher cost of capital. While PG&E acknowledges that memorandum accounts provide a mechanism for ex-post reasonableness review, if they are broadly used in place of current rate recovery, the amounts in these accounts can reach levels that adversely impact PG&E's financial health. To mitigate the impacts on the utility's financial health, the Commission should instead approve forecasts that can provide timely cost recovery, yet consider, where applicable, preserving the Commission's ability to later review actual spending.³⁶⁹³

The Commission should strike a reasonable balance between a utility's financial health and other regulatory principles intended to ensure that customer rates are just and reasonable by approving cost recovery for the programs presented on a forecast basis in the GRC, subject to true-up to actual spending through balancing accounts as proposed by PG&E in this application. For example, instead of using memorandum accounts, the Commission should use balancing accounts that establish reasonable forecasts of costs approved by the Commission to be included in rates on a timely basis. Such a construct can provide a review of customer benefits when there are circumstances beyond the utility's control that require higher spending, or when accelerating work into the near term is more cost efficient or provides better service. Examples of such

³⁶⁹³ PG&E-14, p. 3-5.

approved constructs currently in place are the Vegetation Management Balancing Account (VMBA) that requires a showing of reasonableness prior to recovery of costs above 120 percent of adopted amounts. Similarly, the Wildfire Mitigation Balancing Account (WMBA) requires a showing of reasonableness prior to recovery of costs above 115 percent of the adopted amounts.³⁶⁹⁴

12.3.1 Catastrophic Event Straight-Time Labor Balancing Account (CESTLBA)

PG&E proposes to recover straight time (ST) labor costs associated with its repair and restoration activities for CEMA-eligible events through a new two-way balancing account referred to as the CESTLBA. Under the proposed two-way balancing account, the CESTLBA will be trued up annually through PG&E's annual electric and annual gas true up advice letters.

In their opposition to the CESTLBA, Cal Advocates argues that CEMA is a non-GRC activity and that CEMA straight-time labor and overheads cannot be recovered through the GRC. TURN argues that PG&E's CEMA straight time labor costs associated with existing employees is not incremental and is already funded in the GRC and GT&S proceedings.

The Commission should reject these arguments and approve the CESTLBA in order to avoid the persistent, longstanding dispute regarding the recovery of CEMA straight-time labor costs in the CEMA cost-review proceedings. PG&E discusses this issue in detail in Section 4.6.3.3 above.

12.3.2 Z-Factor Memorandum Account

PG&E proposes to continue the Z-factor mechanism with a modification to update test year and post-test year and PTY revenue requirement adjustments through an advice letter (AL) process. Cal Advocates recommends that the Z-factor should not apply to test year costs.³⁶⁹⁵ TURN recommends that PG&E should be required to file an application to seek recovery of Z-

³⁶⁹⁴ PG&E-14, p. 3-6 to p. 3-8.

³⁶⁹⁵ CALPA-16, p. 23, lines 20-22.

factor costs.³⁶⁹⁶ The Commission had authorized Z-factor adjustments for the TY as well as the PTYs in Sempra's 2019 GRC. Seeking recovery of such costs via advice letter is consistent with the process that the Commission approved for SCE in its most recent GRC. As such, the Commission should authorize the same for PG&E. PG&E addresses this issue in more detail in Section 11.2 above.

12.3.3 Other Balancing Or Memorandum Accounts

12.3.3.1 General Rate Case Memorandum Accounts And Gas Transmission And Storage Memorandum Account

The General Rate Case Memorandum Account (GRCMA) and Gas Transmission and Storage Memorandum Account (GTSMA) track under or over collections related to delayed implementations of future GRC rate cases. In D.22-06-033, the Commission directed that the amounts recorded to the GRCMA and GTSMA be specific to each delayed GRC implementation.³⁶⁹⁷

Currently, the GRCMA tracks under or over collections resulting from a delay in implementing the adopted 2020 GRC revenue requirements in rates. PG&E had proposed to modify the GRCMA to allow tracking of under or over collections resulting from delayed implementation of future GRC rate cases as authorized by the Commission. Similarly, PG&E had proposed to modify the GTSMA to allow tracking under or over collections related to approved GT&S revenue requirements resulting from delayed implementation of future GRC rate cases.³⁶⁹⁸

PG&E's GRC memo accounts track under or over collections related to specific past cases with delayed implementations. PG&E proposed updates to the GRCMA that would make these accounts generic so that they could be used to track activity resulting from any future

³⁶⁹⁶ TURN-13, p. 27, line 11 to p. 28, line 3.

³⁶⁹⁷ PG&E-12, p. 7-8, Table 7-3, line 9.

³⁶⁹⁸ PG&E-12, p. 7-15, lines 26-34.

delayed GRC. TURN recommended PG&E continue to update these accounts for each specific case that may be delayed in the future.³⁶⁹⁹ PG&E has withdrawn its proposal. PG&E agrees with TURN that this issue was addressed in D.22-06-033. On June 23, 15 2022, the Commission approved D.22-06-033 making PG&E's 2023 adopted revenue requirements effective January 1, 2023, in the event a final decision on PG&E's revenue requirements are approved after that date. Pursuant to D.22-06-033, PG&E filed Advice Letter 4628-G/6641-E on July 7, 19 2022, to update its GRCMA to comply with the requirements of that decision.³⁷⁰⁰

12.3.3.2 Additional Disputed And Undisputed Balancing And Memorandum Accounts

In addition to the CESTLBA, Z-Factor Memorandum Account, and GRCMA/GTSMA discussed above, PG&E is proposing to open, modify and/or close other balancing accounts and memorandum accounts in this GRC.

Appendix B to this opening brief lists the uncontested balancing accounts, memorandum accounts, and other uncontested non-forecast issues. The list of uncontested balancing accounts and memorandum accounts includes the name of the uncontested account, a description of the account, any proposed modifications to the account and a reference where it is discussed in PG&E's testimony. The list of other uncontested non-forecast items includes a description of the item and a reference to where it is discussed in PG&E's testimony.

Appendix C to this opening brief lists the contested memorandum accounts and balancing accounts. The list includes a description of the contested account, PG&E's position, a reference to where the contested memorandum or balancing account is addressed in testimony, and a reference to the location in the brief where this account is discussed.

³⁶⁹⁹ PG&E-25, p. 7-12, lines 7-12.

³⁷⁰⁰ PG&E-25, p. 7-12, lines 14-20.

13. UPDATE TESTIMONY (EXHIBIT PG&E-33)

PG&E's Update Testimony, submitted on September 6, 2022, followed the same protocol that has long been followed in GRCs, which specifically establishes a schedule to allow the utility to update for changes in law, tax rate changes, and updates to labor and non-labor escalation rates. Specifically, the Rate Case Plan allows a utility to update following evidentiary hearings for increases in the following areas:

1. Known changes in cost of labor based on contract negotiations completed since the tender of the notice of intent or known changes that result from updated data using the same indexes used in the original presentation during hearings;
2. Changes in non-labor escalation factors based on the same indexes the party used in its original presentation during hearings; and
3. Known changes due to governmental action such as changes in tax rates, postage rates, or assessed valuation.³⁷⁰¹

The process that PG&E followed to serve update testimony at this stage in the proceeding has been in the Rate Case Plan and part of the GRC process for more than thirty years.³⁷⁰²

13.1 PG&E's Updated Escalation Rates Are Reasonable And Should Be Approved.

In our opening testimony, PG&E explained: "PG&E used multiple IHS Markit's First Quarter 2020 Utility Cost Information Service (UCIS) [indexes] to escalate Administrative and General and O&M expenses by functional category. These functional categories are non-labor O&M for electric distribution, nuclear generation, hydro generation, fossil generation, gas distribution, and administrative."³⁷⁰³ Further, "[s]ince many 2023 expense estimates are derived from 2020 recorded costs, it is necessary to account for the effects of inflation on

³⁷⁰¹ D.21-08-036, p. 180 citing D.07-07-004, Appendix A, p. A-36.

³⁷⁰² See D.89-01-040, p. B-26; 1989 Cal. PUC LEXIS 37, *81; 30 CPUC2d 576 ("All testimony and exhibits for updating shall be in fully prepared form and served on appearances on Day 280 as indicated in the rate case plan.").

³⁷⁰³ PG&E-33, p. 2-1, lines 23-29; PG&E-12, p. 3-2, line 18 to p. 3-3, line 4.

PG&E’s expenses between 2020 and 2023.”³⁷⁰⁴ PG&E provided witnesses who described how they used the IHS Power Planner Data in both opening and Update Testimony.³⁷⁰⁵ No intervenors disputed PG&E’s use of the IHS Power Planner data to escalate its costs from the 2020 base year to 2023 and through the attrition years. In our Update Testimony, we updated the same rates using IHS Markit’s Second Quarter 2022 Report.³⁷⁰⁶ PG&E also updated the capital escalation rates from the First Quarter 2020 UCIS using the same IHS Markit Second Quarter Report.³⁷⁰⁷

13.2 PG&E’s Update To Escalation Factors Using IHS Markit Data Is Consistent With Decades Of Commission Precedent

The Updates for the IHS Power Planner should be adopted as the escalation factors in the final decision because:

- The escalation factors clearly fit within the limited scope of appropriate update testimony described in the Rate Case Plan.
- In each case, PG&E is merely updating its earlier forecast by substituting a known and easily quantified change, and otherwise retaining the earlier calculation method.
- The escalation rates are specifically referenced in the Rate Case Plan’s description of update testimony.
- PG&E is substituting a more recent forecast from the same firm that had provided the forecast underlying direct testimony.
- Other than swapping out the earlier figure for the more recently-issued figures, PG&E did not change any previously-used forecast method or rely on a new forecast method.³⁷⁰⁸

³⁷⁰⁴ PG&E-12, p. 3-1, lines 28-30.

³⁷⁰⁵ PG&E-12, Ch. 3 (escalation factors in opening testimony); PG&E-33, Ch. 2 (escalation factors in Update testimony.)

³⁷⁰⁶ PG&E-12, Ch. 3 (escalation factors in opening testimony); PG&E-33, Ch. 2 (escalation factors in Update testimony.)

³⁷⁰⁷ PG&E-33, p. 2-2, line 11 to p. 2-3, line 1.

³⁷⁰⁸ PG&E-33, Ch. 2.

For decades, the Commission has consistently approved of the use of IHS escalation indices and those of its predecessor in utility GRCs.³⁷⁰⁹ The Commission relies on them to escalate costs because they are reliable and based exactly on the types of costs that a utility incurs. As Dr. Peter Griffes explained at the evidentiary hearings:

The indices that have been chosen are chosen because they are reflected – its from Handy-Whitman Indices, which are very much specific to the utility industry, and based on the Federal Energy Regulatory Commission accounts that . . . are required . . . for filings to be made to the Federal Energy Regulatory Commission. So every year, each . . . utility has to report their costs the Federal Energy Regulatory Commission and those are what goes into . . . the indices that are used, the Handy-Whitman Indices, that . . . IHS takes and reports on a historic basis, but then uses those indices to . . . forecast what those indices are likely to do into the future. So . . . the IHS indices are a much better reflection of what the costs are that PG&E will actually be facing.³⁷¹⁰

In SCE's 2021 GRC, the Commission explained:

SCE's capital escalation rates, except for General Plant, are based on the IHS Markit forecasts of the Handy-Whitman Index of Public Utility Construction Costs. SCE's General Plant capital escalation is based on an index built by SCE, which SCE developed by assigning the General Plant cost categories the appropriate IHS Markit variables weighted by recorded General Plant costs for 2018.

SCE provided updated escalation rates to reflect the most current inflationary environment during the update phase of this proceeding. Unless otherwise specified, we adopt SCE's proposed escalation rates for labor, non-labor, and capital costs for 2014-2021. Escalation of costs for 2022 and 2023 is addressed in Post-Test Year Ratemaking (Section 46).³⁷¹¹

Notably, in a motion that TURN filed to strike a different portion of SCE's 2021 GRC

Update testimony, TURN did not move to strike the updated escalation factors based on the IHS

³⁷⁰⁹ D.82-12-055, pp. 3, 9, and 29; 1982 Cal. PUC LEXIS 1209, *13, *23 and *50-51; 10 CPUC2d 155 (approving use of the most recent forecast of inflation by Data Resources, Inc., the predecessor to IHS Markit).

³⁷¹⁰ Tr. Vol 14, 2689:14 to 2690:7, PG&E/Griffes.

³⁷¹¹ D.21-08-036, p. 540.

Markit forecast. TURN reasoned that the use of the IHS forecast in SCE's Update testimony was appropriate because:

Three of SCE's proposed changes in its update testimony appear to clearly fit within the limited scope of appropriate update testimony described in the Rate Case Plan. In each case, SCE appears to be merely updating its earlier forecast by substituting a known and easily quantified change, and otherwise retaining the earlier calculation method.

[¶]. . . [¶]

The same appears to be true for the proposed revenue requirement changes to reflect updated escalation rates and the cost of capital. The labor and non-labor escalation rates are specifically referenced in the Rate Case Plan's description of update testimony. Here, SCE appears to substitute a more recent forecast from the same firm that had provided the forecast underlying SCE's direct testimony.³⁷¹²

Here, as in SCE's 2021 GRC, PG&E's Update Testimony uses the same source of indices and methodologies that PG&E used in its Opening Testimony.³⁷¹³

The Commission also approved the use of IHS Markit data for costs escalation for attrition years in SDG&E and SoCal Gas's 2019 GRC. In that decision, the Commission stated:

In D.19-05-051, the Commission established that in these GRCs, including the post-test years 2020 and 2021, labor and non-labor costs should be based on the IHS Markit Global Insight forecast and the capital investment costs were to be based on an escalated seven-year average of capital additions.³⁷¹⁴

In the current proceeding, TURN also admits that the IHS Markit Global Insight data is sufficiently reliable to use in ratesetting: "TURN prefers that such a customer-oriented measure of inflation be used [to cap authorized spending], but if the Commission prefers a utility-focused inflation measure, it could use a different source, such as the IHS Markit Global Insight (Global Insight) forecast that the utilities often use to calculate GRC escalation rates."³⁷¹⁵

³⁷¹² *Motion of the Utility Reform Network to Strike Portions of Update Testimony Served July 24, 2020, by Southern California Edison Company*, A.19-08-013, pp. 2-3, <<https://docs.cpuc.ca.gov/PublishedDocs/Efile/G000/M344/K124/344124250.PDF>> (as of Oct. 17, 2022).

³⁷¹³ Tr. Vol. 14, 2686:13 to 2687:7, PG&E/Klingler.

³⁷¹⁴ D.21-05-003, p. 30, Finding of Fact 11 (emphasis added).

³⁷¹⁵ TURN-03, p. 40, lines 11-15.

We recognize that the updated escalation factors result in a substantial increase in our revenue requirement due to the increases in inflation in the United States in 2021 and 2022. The purpose of the Update process is to incorporate those inflation rates. The increase attributable to inflation is needed as the prices that PG&E pays for materials and supplies to provide safe and reliable service are similarly increasing.³⁷¹⁶ As PG&E witness Dr. Carla Peterman explained during the Update Testimony hearings:

[W]e don't take raising rates lightly, and [we are] aware of and thought about the impact to our customers. Chapter 5, the rates analysis, shows that. However, we thought it was important to provide this update, because we are seeing the cost of service increase, and our primary responsibility is to provide safe and reliable service. So as we're seeing extraordinary inflation across the country, we're not immune to that at PG&E. So we are seeing the cost of those services go up, so we filed this update very much consistent with the rate case plan, which allows for putting information in about inflation.³⁷¹⁷

13.2.1 The Updated Escalation Factors Must Be Adopted In Their Entirety

The Updated Escalation Factors for the years 2021 to 2026 must be adopted in their entirety to accurately escalate the 2020 base year costs PG&E used to develop its 2021-2026 forecasts. PG&E's Update Testimony is the best evidence of the impact of inflation on PG&E's 2020 base year costs. The escalation factors in the Update Testimony reflect the most current data on the impacts of inflation on utility prices in the record of the proceeding for each year from 2021-2026.

Tables 2-1 (Non Labor Rates) and 2-3 (Capital Rates) represent the IHS Markit data from the Second Quarter 2022 report. Tables 2-2 (Non Labor Rates) and 2-4 (Capital Rates) represent the outdated data from the First Quarter 2020 report, which contained a forecast that was produced before the Covid pandemic, materials shortages, and higher inflation rates throughout the United States.

³⁷¹⁶ Tr. Vol. 15, 2808:1-16, PG&E/Peterman.

³⁷¹⁷ Tr. Vol. 15, 2804:6-21, PG&E/Peterman.

The IHS Markit price indexes in PG&E's update include **actual** inflation rates for 2021.³⁷¹⁸ As PG&E witness Dr. Peter Griffes explained at the evidentiary hearings, the amounts in line one of Tables 2-1 and 2-3 of PG&E's Update Testimony³⁷¹⁹ for 2021 are actuals rather than forecast data for 2021. As Dr. Griffes indicated:

. . . they are not forecast, they are actual history. The indices essentially went up by . . . each of those amounts in . . . each of the columns in that year . . . between 2020 and 2021.”³⁷²⁰

The rates for 2022 are in part based on the amounts recorded in the first half of 2022 and is based on a forecast for the second half of 2022 and the remaining years of the GRC period.³⁷²¹

The 2022 figures in column 2 of Tables 2-1 and 2-2 are forecasts that were based on approximately 6 months of actual data, with a forecast for the remaining months of 2022, based on the most recent IHS Markit report available to PG&E.³⁷²² The most recent report provides more certainty than the First Quarter 2020 report for the year 2022 that PG&E initially used in its forecasts because it was prepared more than two years later and contains partial year actual data in addition to a forecast.³⁷²³

During the evidentiary hearings, ALJ Larsen noted, that unlike PG&E's original escalation factors, some of the values in Tables 2-1 and 2-3 beginning in 2023 are negative.³⁷²⁴ As Dr. Griffes explained, for those years, “the indices essentially have negative growth rates, which means, essentially, the index goes down, which means it should . . . be a correction in costs

³⁷¹⁸ Tr. Vol 14, 2682:6 to 2683:6, PG&E/Griffes.

³⁷¹⁹ PG&E-33, p. 2-2, Table 2-1; p. 2-3, Table 2-3.

³⁷²⁰ Tr. Vol 14, 2684:8-22, PG&E/Griffes.

³⁷²¹ Tr. Vol 14, 2683:23 to 2686:12, PG&E/Griffes.

³⁷²² Tr. Vol 14, 2685:4-23, PG&E/Griffes.

³⁷²³ Tr. Vol 14, 2682:6 to 2683:6, PG&E/Griffes.

³⁷²⁴ Tr. Vol 14, 2678:2-12, PG&E/Griffes.

during those periods.”³⁷²⁵ Thus while the actual data for 2021 and the 2022 forecast show higher inflation rates, the forecast for the later years shows a post-inflationary period with a forecasts of cost decreases that will reduce customer costs.

The IHS Markit data in the Update must be taken as an entire comprehensive replacement for the data in the First Quarter 2020 report that PG&E submitted with its initial testimony. The First Quarter 2020 forecasts, as demonstrated by the Second Quarter 2022 IHS Markit data, does not reflect current inflation rates. Given that most of the inflationary impact occur in 2021 and 2022 in the IHS data, the Commission cannot implement the escalation factors in such a way that would ignore the actual recorded data for 2021 and 2022, and use only the lower or negative forecasted rates for the later years. The data must be taken as a whole to provide an accurate estimate of the impact of inflation during the entire 2021-2026 period, including the inflationary period and, hopefully the periods of correction that follow it.

To alleviate any concern about whether the 2022 inflation rates were accurately forecast, PG&E proposed at the Update hearings to make available the next two IHS Markit quarterly reports, the Q3 2022 Report and the Q4 2022 Report.³⁷²⁶ Specifically PG&E proposed to make available the reports themselves and reproduce Table 2-1 (IHS Markit Q2 2022 O&M Non-Labor Escalation Rates, 2021-2026) and Table 2-3 (IHS Markit Q2 2022 Capital Escalation Rates 2021-2026) with the Q3 2022 Report data and the Q4 2022 Report Data (subject to appropriate confidentiality treatment). The Q4 2022 Report will have the **final** recorded inflation data for both 2021 and 2022 and will be available in late January 2023. As permitted by ALJ DeAngelis, PG&E will submit this data as a late-filed exhibit by motion for a more complete evidentiary record.³⁷²⁷

³⁷²⁵ Tr. Vol. 14, 2681:25 to 2682:5, PG&E/Griffes.

³⁷²⁶ Tr. Vol 15, 2751:21 to 2753:13.

³⁷²⁷ Tr. Vol 15, 2829:25 to 2834:6.

13.3 PG&E's Update For Tax Changes Are Reasonable And Should Be Approved.

PG&E's Update Testimony also included updates for three tax changes: (A) Tax adjustment to comply with Internal Revenue Service Rules; (B) Inflation Reduction Act – related changes; and (C) Gas Transmission Accounting Method Changes.³⁷²⁸ The federal tax changes in the Update Testimony are discussed in detail in Section 10.2.2 of this Opening Brief.

³⁷²⁸ PG&E-33, Ch. 3.

14. MEMORANDUMS OF UNDERSTANDING

14.1 Small Business Utility Advocates

PG&E has entered into a Memorandum of Understanding with SBUA regarding service and support to PG&E's small business customers during the 2023 GRC period (SBUA MOU).³⁷²⁹ The MOU reflects PG&E's continued commitment to serving its small and medium business customers, as well as its continued collaboration and partnership with SBUA on these issues. Specifically, the SBUA MOU provides that PG&E will direct \$6.5 million annually to provide outreach and support for PG&E's small and medium business customers through its programs and other activities that benefit small and medium business customers.³⁷³⁰

The SBUA MOU reflects the parties' agreement on a broad set of activities and initiatives including the following:

- PG&E will spend the authorized funds on support for small and medium business outreach and engagement through digital and other communication channels;³⁷³¹
- PG&E will continue to provide outreach and support through its Small and Medium Business organization to connect small and medium business customers to PG&E tools, resources, programs, services and Integrated Demand-Side Management offerings;³⁷³²
- PG&E will continue to maintain and improve its dedicated website for small and medium business customers and the "Your Account" portal to allow small and medium businesses and other commercial customers to indicate their preferred communication method for account notifications;³⁷³³
- PG&E will continue supporting economic development activities and working with small and medium businesses to identify contracting opportunities;³⁷³⁴ and

³⁷²⁹ PG&E-06-E, Ch. 2, Attachment A, p. 2-AtchA-1.

³⁷³⁰ PG&E-06-E, Ch. 2, Attachment A, Section 2.1, p. 2-AtchA-2.

³⁷³¹ PG&E-06-E, Ch. 2, Attachment A, Section 2.1.1, p. 2-AtchA-3.

³⁷³² PG&E-06-E, Ch. 2, Attachment A, Section 2.1.2, p. 2-AtchA-4.

³⁷³³ PG&E-06-E, Ch. 2, Attachment A, Section 2.1.5.2, p. 2-AtchA-5.

³⁷³⁴ PG&E-06-E, Ch. 2, Attachment A, Section 6.1, p. 2-AtchA-8.

- PG&E will provide education and assistance to small and medium businesses to help them complete the necessary processes and applications to secure contracts to provide materials and services to PG&E.³⁷³⁵
- Conduct a high-level study on small businesses in Environmental and Social Justice communities.

We believe that the SBUA MOU is reasonable and in the best interest of customers by supporting small and medium businesses in our service area. We respectfully request that the Commission approve the SBUA MOU in this proceeding.

14.2 Center For Accessible Technology

PG&E has entered into an MOU with the Center for Accessible Technology (CforAT) to improving accessibility for customers throughout our service area (CforAT MOU).³⁷³⁶ In the CforAT MOU, the parties agreed that:

- PG&E will spend the equivalent of \$1.7 million per year (a total of \$6.8 million for the 2023 GRC period) on activities to improve accessibility;³⁷³⁷
- PG&E will prepare and distribute an annual report for CforAT and any interested parties on PG&E's activities and spending to promote accessibility;³⁷³⁸
- PG&E will continue to employ a Disability Access Coordinator who will be responsible for coordinating and shaping Company-wide strategies to improve accessibility;³⁷³⁹
- PG&E will prioritize the accessibility of customer communications and engagement around the issue of de-energization.³⁷⁴⁰ and

³⁷³⁵ PG&E-06-E, Ch. 2, Attachment A, Section 6.1, p. 2-AtchA-8.

³⁷³⁶ PG&E-06-E, Ch. 2, Attachment B, p. 2-AtchB-1.

³⁷³⁷ PG&E-06-E, Ch. 2, Attachment B, Section 2.1, p. 2-AtchB-2.

³⁷³⁸ PG&E-06-E, Ch. 2, Attachment B, Section 2.2, p. 2-AtchB-2.

³⁷³⁹ PG&E-06-E, Ch. 2, Attachment B, Section 2.3, p. 2-AtchB-2.

³⁷⁴⁰ PG&E-06-E, Ch. 2, Attachment B, Section 3.1, p. 2-AtchB-3.

- Prior to the start of each calendar year, PG&E will meet with CforAT and any interested parties to discuss planned accessibility spending for the upcoming calendar year.³⁷⁴¹

The CforAT MOU identifies a broad set of eligible activities that PG&E may pursue with the allocated funding, including continuing to fund a full time Disability Coordinator position, website accessibility, communications access issues, accessibility of PG&E's CSOs and NPCs, and activities related to temporary construction and utility pole placement in the path of travel.³⁷⁴²

We believe that the CforAT MOU is reasonable and in the best interest of customers by continuing our strong support for accessibility in our service area. We respectfully request that the Commission approve the CforAT MOU in this proceeding.

14.3 National Diversity Coalition

PG&E has entered into an MOU with the NDC to support diverse communities, such as leveraging new pathways for outreach and education and supporting economic opportunities for communities of color (NDC MOU).³⁷⁴³ In the NDC MOU, the parties agree to terms that provide, among other things, that:

- PG&E will undertake a commitment to spend a total of \$3.2 million over the 4 year 2023 GRC period on the Technical Assistance Program (TAP) and report to NDC on an annual basis the amount spent supporting TAP activities including the amount of labor tracked to the TAP order;³⁷⁴⁴
- PG&E will confer with NDC and solicit its feedback regarding ways to increase outreach to small and micro businesses;³⁷⁴⁵
- PG&E will continue to invite low income and community of color advocates to participate on a Customer Advisory Panel, that will occur at least twice per year and

³⁷⁴¹ PG&E-06-E, Ch. 2, Attachment B, Section 2.4, p. 2-AtchB-3.

³⁷⁴² PG&E-06-E, Ch. 2, Attachment B, pp. 2-AtchB-6 to 2-AtchB-8.

³⁷⁴³ PG&E-06-E, Ch. 3, Attachment A, p. 3-AtchA-1.

³⁷⁴⁴ PG&E-06-E, Ch. 3, Attachment A, Section 2.1.1, p. 3-AtchA-2.

³⁷⁴⁵ PG&E-06-E, Ch. 3, Attachment A, Section 2.1.6, p. 3-AtchA-3.

will be attended by at least one officer from PG&E's Regulatory Affairs Organization, Customer Care Organization, or External Affairs Organization;³⁷⁴⁶

- PG&E will host an annual meeting with NDC that is attended by at least two EVPs. In the alternative, PG&E may choose to host two meetings in a given year at which at least one EVP is in attendance at each meeting.³⁷⁴⁷
- The Chief Executive Officer of PG&E Corporation will attend two of the annual meetings over the four year 2023 GRC period;³⁷⁴⁸
- PG&E will spend a total of \$800 thousand over the 2023 GRC period towards work with CBOs. As part of this work, PG&E will work with CBOs to disseminate in multiple languages, general information about financial assistance and bill savings programs, rate options, wildfire safety related topics and emergency preparedness or other emergent initiatives to help reach vulnerable customers. PG&E will work with NDC to help identify appropriate CBOs to include in outreach education and awareness solicitation opportunities;³⁷⁴⁹
- PG&E will coordinate with NDC to conduct at least two workshops or trainings per year for low income constituents for marketing and education on PG&E's low income and disadvantaged communities programs;³⁷⁵⁰ and
- PG&E will establish aspirational goals of 40 percent overall and 25 percent minority spending for supplier diversity annually for the 2023 to 2026 GRC period and report on its annual aspirational goals for overall and minority spending for supplier diversity in the next GRC.³⁷⁵¹

We believe that the NDC MOU is reasonable and in the best interest of customers by continuing our strong support for the diverse communities that we serve. We respectfully request that the Commission approve the NDC MOU in this proceeding.

³⁷⁴⁶ PG&E-06-E, Ch. 3, Attachment A, Section 2.2.3, p. 3-AtchA-4.

³⁷⁴⁷ PG&E-06-E, Ch. 3, Attachment A, Section 2.3.1, p. 3-AtchA-4.

³⁷⁴⁸ PG&E-06-E, Ch. 3, Attachment A, Section 2.3.2, p. 3-AtchA-4.

³⁷⁴⁹ PG&E-06-E, Ch. 3, Attachment A, Section 2.4, p. 3-AtchA-5.

³⁷⁵⁰ PG&E-06-E, Ch. 3, Attachment A, Section 2.5.2, p. 3-AtchA-6.

³⁷⁵¹ PG&E-06-E, Ch. 3, Attachment A, Section 2.6.1., p. 3-AtchA-6.

14.4 Engineers And Scientists of California Local 20

PG&E has entered into an MOU with the Engineering and Scientists of California Local 20 (ESC) regarding PG&E Academy training for engineers during the 2023 GRC period (ESC MOU).³⁷⁵²

The ESC MOU resolves all issues between the parties with respect to PG&E Academy.³⁷⁵³ And provides that: (1) PG&E will conduct preparation sessions for each gas and electric ADE exam given in 2023-2026 substantially similar to the ADE exam preparation sessions provided in 2021;³⁷⁵⁴ (2) PG&E will provide five hours per week of paid study time to each student enrolled in the Estimator Training Program and New Business Representative training programs;³⁷⁵⁵ and (3) PG&E and ESC mutually commit to work cooperatively to improve, modernize, and enhance the effectiveness of end-to-end training, testing, and professional development of employees covered by the contractual training programs for certain job classifications.³⁷⁵⁶

We believe that the ESC MOU is reasonable and in the best interest of customers by enhancing training and opportunities for our employees so that they are able to better serve our customers. We respectfully request that the Commission approve the NDC MOU in this proceeding.

³⁷⁵² The ESC MOU is provided in the *Joint Motion of Pacific Gas and Electric Company (U 39 M) and the Engineers and Scientists of California Local 20 to Admit Late Filed Exhibit Into Evidence* (Sept. 16, 2022), Attachment A. Additional discussion of the ESC MOU can be found in Section 8.5.1.2.

³⁷⁵³ ESC MOU, p. 3, Section 1.7.

³⁷⁵⁴ ESC MOU, p. 4, Section 3.1.

³⁷⁵⁵ ESC MOU, p. 4, Section 3.2.

³⁷⁵⁶ ESC MOU, p. 4, Section 3.3.

15. OTHER ISSUES

PG&E has not identified any other issues besides those addressed in Sections 1-15 and Appendices A-H of this opening brief.

16. CONCLUSION

Based on the extensive evidence presented, the precedent cited, and the arguments in this opening brief, PG&E respectfully requests that the Commission make the following findings and issue the following orders. For Items 1 and 3-6 below, PG&E's original forecasts and corresponding revenue requirements would be revised pursuant to the terms of the stipulations and settlements described in Sections 5, 7 and 9 of the opening brief and attached as Appendices E, F, and G to the opening brief.

1. Finding that PG&E's proposed forecasts for expense and capital expenditure for each of the programs, MWCs, and MATs at issue in this proceeding are just and reasonable including:
 - a. The contested programs, MWCs, and MATs described in this opening brief;
 - b. The uncontested programs, MWCs, and MATs identified in Appendix A;
2. Finding that PG&E's escalation and tax proposals in the Update Testimony, described in Section 13 of this opening brief, are just and reasonable;
3. Finding that the proposed revenue requirement for the electric distribution function in 2023 and related proposals are just and reasonable and that PG&E may reflect the adopted electric distribution revenue requirement in rates effective January 1, 2023;
4. Finding that the proposed revenue requirement for the gas distribution, transmission, and storage function in 2023 and related proposals are just and reasonable and that PG&E may reflect the adopted gas distribution, transmission, and storage revenue requirement in rates effective January 1, 2023;
5. Finding that the proposed revenue requirement for the electric generation function in 2023 and related proposals are just and reasonable and that PG&E may reflect the adopted electric generation revenue requirement in rates effective January 1, 2023;
6. Approving as reasonable PG&E's proposals for the creation, modification, or closure of balancing and memorandum accounts summarized in Appendices B and C;
7. Approving as reasonable the uncontested non-financial issues in Appendix B;

8. Determining that PG&E's approach to risk management and safety, as described in Section 2 of this opening brief, is reasonable and prudent;
9. Approving PG&E's updated Peak Day Demand Forecast and the retention of the Los Medanos natural gas storage facility, both of which are described in Section 3.6;
10. Rejecting the JCCA proposals described in Section 5.8.4;
11. Approving PG&E's proposed depreciation rates, as described in Section 10.1;
12. Approving the Other Operating Revenues that PG&E receives from transactions not directly associated with the distribution, generation, gas transmission, or sale of electric energy or natural gas described in Section 10.5;
13. Approving PG&E's calculation method and resulting 2023 forecast for payroll taxes and other taxes described in Section 10.7;
14. Approving the A&G allocation factor and the franchise fee factor described in Section 10.8
15. Approving PG&E's proposals for post test-year ratemaking and the Z-Factor, as described in Section 11;
16. Discontinue one of the reporting requirements in D.15-04-024 regarding the SFGTSA as described in Section 12.2;
17. Approving the Memorandums of Understanding described in Section 14;
18. Approving the stipulations on contested issues described in Sections 5, 7 and 9 and included as Appendices E, F, and G to the opening brief;
19. Rendering Findings of Fact and Conclusions of Law and issuing Orders consistent with the findings and approvals described above.

Respectfully submitted,

PACIFIC GAS AND ELECTRIC COMPANY

By: /s/ Mary A. Gandesbery
MARY A. GANDESBERY

Law Department
PACIFIC GAS AND ELECTRIC COMPANY
Post Office Box 7442
San Francisco, California 94120
Telephone: (510) 316-3566
Fax: (415) 973-5520
E-Mail: mary.gandesbery@pge.com

Attorneys for
PACIFIC GAS AND ELECTRIC COMPANY

Dated: November 4, 2022

17. GLOSSARY

17.1 Acronyms and Abbreviations

The following acronyms and abbreviations are used in PG&E's Opening Brief.

ACRONYM	DEFINITION
\$/kW	dollars per kilowatt
%SMYS	percent Specified Minimum Yield Strength
2020 WMCE	2020 Wildfire Mitigation and Catastrophic Events Application
49 CFR	Title 49 of the Code of Federal Regulations - Transportation
A&G	Administrative And Generation
A.	Application
A/V	audio/visual
AACE	Association for the Advancement of Cost Engineering
AAR	After-Action Reviews
AB	Assembly Bill
ACBA	Atmospheric Corrosion Balancing Account
ACCUMA	Avoided Costs Calculator Update Memorandum Account
ACIBA	Alternating Current Interference Balancing Account
ACSR	Aluminum Conductor Steel-Reinforced
AD&D	Group Life And Accidental Death And Dismemberment
ADD	Advanced Data Download
ADE	Associate Distribution Engineer
ADI	Asset Data Improvement
ADMS	Advanced Distribution Management System

ACRONYM	DEFINITION
ADR	Alarm Definition Rationalization
AFSI	Adjusted Financial Statement Income
AHJ	Agency Having Jurisdiction
AIS	Analytics, Innovation and Strategy
AKM	Asset Knowledge Management
AL	Advice Letter
ALJ	Administrative Law Judge
AM&SO	Asset Management and System Operations
AMCDOP	Adjustment Mechanism for Costs Determined in Other Proceedings
AMI	Advanced Metering Infrastructure
AMI PMO	Advanced Meter Infrastructure Project Management Office
AMP	Arrearage Management Plan
AOC	Aviation Operations Center
AQI	Air Quality Index
ASA	Average Speed Of Answer
ASL	Average Service Lives
ASU	Accounting Standards Update
ASV	Automatic Shut-Off Valve
AWS	Amazon Web Services
BAA	Business Associate Agreement
BCA	Balancing Charge Account
BCR	Benefit Cost Rate
BFR	Bundled Fill Rate
BGSDBA	Below-Ground Storage Decommissioning Balancing Account

ACRONYM	DEFINITION
BOD	Boards of Directors
BVLOS	Beyond Visual Line of Sight
C&E	Compliance And Ethics
CA	California
CAA 2021	Consolidated Appropriations Act of 2021
Cal Advocates or CALPA	Public Advocates Office at the California Public Utilities Commission
CalGEM	California Geologic Energy Management Division
CAM	Cost Allocation Mechanism
CAP	Corrective Action Plan
CAP	Corrective Action Program
CARB	California Air Resources Board
CARE	California Alternate Rates For Energy
CAVAMA	Climate Adaptation Vulnerability Assessment Memorandum Account
CBA	Casings Balancing Account
CBL	Cement Bond Logging
CBU	Capacitive Balancing Unit
CCFT	California Corporation Franchise Tax
CCO	Chief Customer Officer
CCPA	California Consumer Privacy Act
CCPA	California Consumer Privacy Act of 2018
CCR	California Code of Regulations
CCVT	Capacitive Couple Voltage Transformer
CDGSWMA	California Distributed Generation Statistics Website Memorandum Account

ACRONYM	DEFINITION
CDPMA	Critical Documents Program Memorandum Account
CECO	Chief Ethics and Compliance Officer
CEM	Capitalized Emergency Material
CEMA	Catastrophic Events Memorandum Account
CERS	Customer Experience and Regulatory Strategy
CES	Customer Energy Solutions
CESTBLA	Catastrophic Event Straight-Time Labor Balancing Account and CEMA Straight-Time Labor Balancing Account
CESTLBA	CEMA Straight-Time Labor Balancing Account
CET	Clean Energy Transportation
cFCI	Communicating Faulted Circuit Indicator
CFILC	California Foundation for Independent Living Centers
CforAT	Center For Accessible Technology
CFSA	Core Firm Storage Account
CGMA	Cushion Gas Memorandum Account
CGR	California Gas Report
CHP	California Highway Patrol
CIC	Cable-In-Conduit
CIS	Close Interval Survey
CM	Computer Mortality
CMEP	Community Microgrid Enablement Program
CMET	Community Microgrid Enablement Tariff
COBRA	Consolidated Omnibus Budget Reconciliation Act
COL	Conclusions Of Law

ACRONYM	DEFINITION
Colusa or CGS	Colusa Generating Station
Commission or CPUC	California Public Utilities Commission
Company	Pacific Gas and Electric Company
COO	Chief Operating Officer
COR	Cost Of Removal
Corporate Affairs	Corporate Affairs Department
Covid-19	Coronavirus
CP	Commercial Policy or Compliance Period
CPBA	Casings Program Balancing Account
CPCS	Condensate Polisher Computer System
CPDCA	Core Pipeline Demand Charge Account
CPE	Central Procurement Entity
CPI	Consumer Price Index
CPI-U	All Urban Consumer Price Index
CPP	Critical Peak Pricing
CPRA	California Privacy Rights Act of 2020
CPUC	California Public Utilities Commission
CRC	Community Resource Center
CRESS	Corporate Real Estate Strategy And Services
CRM	Customer Relationship Manager
CRO	Chief Risk Officer
CRP	Customer Revenue Processing
CRPP	Community Rebuild and Resiliency Program
CRR	Corporate Risk Register

ACRONYM	DEFINITION
CS	Circuit Segment
CSD	California Department of Community Services and Development
CSL	Customer Service Lead
CSLC	California State Lands Commission
CSO	Chief Safety Officer
CSP	Contractor Safety Program
CSR	Customer Service Representatives
CSR	Critical Safety Risk
CSS	Customer Service Support
CT	Current Transformer
CVA	Climate Vulnerability Assessment
CVFPB	Central Valley Flood Protection Board
CWIP	Construction Work In Progress
Dam Safety	Large Uncontrolled Water Release
DART	Days Away, Restricted, And Transferred Rate
DASH	Dynamic Automated Seismic Hazard
DBPBA	Diary Biomethane Pilots Balancing Account
DBPMA	Dairy Biomethane Pilots Memorandum Account
DBSMA	Dairy Biomethane Solicitation Memorandum Account
DCC	Distribution Control Center
DC-ESRP	Defined Contribution Executive Supplemental Retirement Plan
DCISC	Diablo Canyon Independent Safety Committee
DCP	Delta Conveyance Project
DCPP or Diablo Canyon	Diablo Canyon Power Plant

ACRONYM	DEFINITION
DCRBA	Diablo Canyon Retirement Balancing Account
DDAR	Disability Disaster Access and Resources
DE&R	Direct Examination and Repair
DEI	Diversity, Equity and Inclusion
DEMP	Data and Energy Management Products
DER	Distributive Energy Resources
DERA	Distributed Energy Resource Provider Agreement
DERDDA	Distributed Energy Resources Distribution Deferral Account
DERMS	Distributed Energy Resources Management System
DFA	Distribution Fault Anticipation
DG Stats	Distributed Generation Statistics
DGEMS	Distributed Generation-Enabled Microgrid Services
DGO	Distribution Grid Operations
DIDF	Distribution Investment Deferral Framework
DLE	Data Loss Event
DM	Data Management
DMA	Data Management and Analytics
DMS	Distribution Management System
DMV	Department of Motor Vehicles
DOGGR	Division of Oil, Gas, and Geothermal Resources
DQA	Data Quality Assurance
DRA	Division of Ratepayer Advocates
DRPTMA	Distribution Resources Plan Tools Memorandum Account
DS	Defensible Space

ACRONYM	DEFINITION
DSAP	Distribution System Automation and Protection
DSIMA	Dimmable Streetlight Implementation Memorandum Account
DSOD	California Division of Safety of Dams
DVC	Disadvantaged Vulnerable Communities
DWR	Department of Water Resources
E&O	Education and Outreach
E3	Energy And Environmental Economics, Inc.
EAP	Employee Assistance Program
EC	Electric Correction
EC ISSP	Electrically-Connected Isolated Steel Services Program
ECA	Engineering Critical Assessment
ECABA	Engineering Critical Assessment Balancing Account
ECCVM	Event Classification Through Current and Voltage Monitoring Sensors
ECDA	External Corrosion Direct Assessment
ED	Electric Distribution
EDIT	Excess Deferred Income Taxes
EDM	Electric Distribution Maintenance
EDN	Electric Distribution Network
EDPM	Electric Distribution Preventive Maintenance
EER	Electric Emergency Recovery
EG	Electric Generation
EGA	Electric and Gas Acquisition
EH&S	Enterprise Health And Safety
EMANI	European Mutual Association For Nuclear Insurance

ACRONYM	DEFINITION
EMAT	Electromagnetic Acoustic Transducer
ENG	Employee Network Groups
EO	Electric Operations
EOC	Emergency Operations Center
EOEP	Enhanced Oversight and Enforcement Process
EORM	Enterprise and Operational Risk Management
EPC	Enterprise Program Compliance
EPP	Energy Policy and Procurement
EPS	Earnings Per Share
EPSS	Enhanced Powerline Safety Settings
ERIM	Enterprise Records and Information Management
ES	Energy Supply
ESA	Energy Savings Assistance
ESC	Engineers and Scientists of California Local 20
eSCR	Electronic Supplier Change Request
ESD	Emergency Shutdown
ESFT	Enterprise Secure File Transfer
ESG	Environmental, Social, And Governance
ESH	Enterprise Safety and Health
ESI	Energy Strategy and Innovation
ESRI	Environmental Systems Research Institute
ETRM	Energy Trading and Risk Management
EU	European Union
EV	Electric Vehicle

ACRONYM	DEFINITION
EVC 2	Electric Vehicle Charge 2
EVCN	Electric Vehicle Charge Network
EVIP	Electric Vehicle Infrastructure Program
eVIP	Electric Vehicle Incentive Program
EVP	Executive Vice President
EWM	Extended Warehouse Management
FAI	Field Asset Inventory
FAQ	Frequently Asked Question
FDA	Facility Damage Action
FERA	Federal Emergency Relief Act or Family Electric Rate Assistance
FERC	Federal Energy Regulatory Commission
FES	Field and Engineering Support
FFD	Fit For Duty
FFO/Debt	Funds From Operations To Total Debt Ratio
FIMP	Facility Integrity Management Program
FIMS	Fleet Information Management System
FIT	Federal Income Tax
FLEX	Flexible Benefits Program
FLISR	Fault Location, Isolation and Service Restoration
FM	Field Metering
FMCSA	Federal Motor Carrier Safety Administration
FMEA	Failure Mode and Effects Analysis
FOF	Finding Of Fact
FRMMA	Fire Risk Mitigation Memorandum Account

ACRONYM	DEFINITION
FRP	First Respondent Web Portal
FS	Fuel Settlements
FSC	Fire Safe Council
FSR	Field Safety Re-assessment
FSR	Flight Safety Review
FTB	Franchise Tax Board
FTE	Full-Time Employees or Full-Time Equivalent
GACC	Geographic Area Coordination Center
Gateway or GGS	Gateway Generating Station
GCC	Gas Control Center
GD/GT	Gas Distribution/Gas Transmission
GEMS	Gas and Electric Meter Services
GHG	Greenhouse Gas
Global Insight	IHS Markit Global Insight
GO	Gas Operations
GO Pool	General Office Vehicle Pool
GOCTI	Gas Operations Control Technology Integration
GRC	General Rate Case
GRCMA	General Rate Case Memorandum Accounts
GRN	Gamma-Ray Neutron
GS	Gas Storage
GS&A	Gas Scheduling and Accounting
GSAM	Gas Storage Asset Management
GSBA	Gas Storage Balancing Account

ACRONYM	DEFINITION
GSEMS	Gas Safety Excellence Management System
GSHUT	Extended Unplanned Shutdown of Hydro Generation Facility
GSRRMA	Gas Statutes, Regulations, and Rules Memorandum Account
GT	Gas Transmission
GT&D	Gas Transmission and Distribution
GT&S	Gas Transmission and Storage
GTSMA	Gas Transmission and Storage Memorandum Account
GTSRSM	Gas Transmission and Storage Revenue Sharing Mechanism
HBPP	Humboldt Bay Power Plant
HCA	High Consequence Area
HE	Hearing Exhibit
HFRA	High Fire Risk Area
HFTD	High Fire Threat District
HIPAA	Health Insurance Portability and Accountability
HLBA	Hydro Licensing Balancing Account
HPZ	High Pedestrian Zone
HR	Human Resources
HRA	Health Reimbursement Account
HSMS	Health and Safety Management System
HTBA	Hydrostatic Testing Balancing Account
Humboldt or HBGS	Humboldt Bay Generating Station
IA	Internal Audit
IBEW	International Brotherhood of Electrical Workers
IC	Internal Corrosion

ACRONYM	DEFINITION
ICBA	Internal Corrosion Balancing Account
ICDA	Internal Corrosion Direct Assessment
ICDAMA	Internal Corrosion Direct Assessment Memorandum Account
ICE	Intercontinental Exchange
IFR	Interim Final Rule
IGPI	Integrated Grid Planning and Innovation
IIC	Items Impacting Comparability
IIP	Integrated Investment Planning
ILI	In-Line Inspection
ILIBA	In-Line Inspection Balancing Account
ILIMA	In-Line Inspection Memorandum Account
IMU	Inertial Measurement Unit
INPO	Institute of Nuclear Power Operators
Internal Fleet Program	Internal Fleet Electrification Program
IOC	Impacted Occupancy Count
IOU	Investor-Owned Utilities
IP	Internet Protocol
IPA	Intelligent Privacy Automation
IQA	Imagery Quality Assurance
IRA	Inflation Reduction Act
IRC	Internal Revenue Code
IRP	Integrated Resource Planning
IRS	Internal Revenue Service
ISM	Independent Safety Monitor

ACRONYM	DEFINITION
ISOC	Independent Safety Oversight Committee
ISP	Independent Storage Provider
ISRMP	Integrated Seismic Risk Management Program
IST	Integrated Scoping Team
IT	Information Technology
ITAM	Information Technology Asset Management
ITEC	Information Technology Emergency Communications
IWRMC	International Wildfire Risk Mitigation Consortium
JBB	James B. Black
JCE	Joint Comparison Exhibit
JEMS	Jobsite Energy Management Systems
JIT	Just-In-Time
KRI	Key Risk Indicator
L&M	Locate and Mark
L407MA	Line 407 Memorandum Account
LBOR	Load Break
LED	Leadership And Employee Development
LEIP	Line Elimination Incentive Program
LEM	Land And Environmental Management
LGUWR	Large Uncontrolled Water Release
LIF	Leader in the Field
LIHEAP	Low Income Home Energy Assistance Program
LL&P	Large Light and Power
LMMA	Locate and Mark Memorandum Account

ACRONYM	DEFINITION
LOB	Line of Business
LOC	Letter Of Credit or Loss of Containment
LOF	Likelihood of Failure
LRA	Local Responsibility Area
LTD/STD PAYGO	Long Term Disability/Short Term Disability Pay-As-You-Go
LTSA	Long Term Service Agreement
LTSP	Long Term Seismic Program
LUWR	Large Uncontrolled Water Release
LVC	Large Volume Customer
LVCM	Large Volume Customer Meter
LVCR	Large Volume Customer Regulator
LVC-Type	Large Volume Customer Type
M&CRM	Market And Credit Risk Management
M&S	Materials And Supplies
MAP	Mapping Advancement Program
MAT	Maintenance Activity Type
MAVF	Multi-Attribute Value Function
MBL	Medical Baseline
MCA	Moderate Consequence Area
MCC	Motor Control Center
MCOPMA	Measurement and Control Over Pressure Protection Memorandum Account
MCSRBA	Measurement and Control Station Rebuilds Balancing Account
MDM	Meter Data Management

ACRONYM	DEFINITION
MFL	Magnetic Flux Leakage
MGMA	Microgrids Memorandum Account
MGRA	Mussey Grade Road Alliance
MIP	Microgrid Incentive Program
MIS	Microgrid Islanding Study
ML	Machine Learning
MMcf	Millions of Cubic Feet
MMcf/d	Million Cubic Feet Per Day
MOC	Management of Change
MOU	Memorandum Of Understanding
MSO	Motorized Switch Operator
MWC	Major Work Category
N&T	Noise and Temperature
NADM	North American Drought Monitor
NARUC	National Association of Regulatory Utility Commissions
NATS	North American Training Solutions
NCJPA	Northern California Joint Pole Association
NDC	National Diversity Coalition
NDT	Diablo Canyon Nuclear Decommissioning Trust
NEETRAC	National Electric Energy Testing Research and Applications Center
NEI	Nuclear Energy Institute
NEIL	Nuclear Electric Insurance Limited
Net Zero by 2045	California's Goal of Net Zero Greenhouse Gas Emissions By 2045
NFA	No Further Action

ACRONYM	DEFINITION
NGM	Next Gen Metering
NGSS	Natural Gas Storage Strategy
NGSWR	Natural Gas Storage Well or Reservoir
NIFC	National Interagency Fire Center
NOAA	National Oceanic and Atmospheric Administration
NOLs	Net Operating Losses
NPV	Net Present Value
NRC	Nuclear Regulatory Commission
NRCBA	Nuclear Regulatory Commission Regulatory Balancing Account
NSBE	National Society of Black Engineers
NSC	National Safety Council
NSGBA	New System Generation Balancing Account
NSGC	New System Generation Charge
NTBA	Non-Tariffed Balancing Account
NTP&S	Non-Tariffed Products and Services
O&M	Operations & Maintenance
OAM	Overhead Asset Management
OCMA	Officer Compensation Memorandum Account
OEC	Operations Emergency Center
OEM	Original Equipment Manufacturer
OH	Overhead or Occupational Health Department
OIC	Officer in Charge
OIR	Order Instituting Rulemaking
OM	Operational Management

ACRONYM	DEFINITION
OMS	Outage Management System or Operational Management System
OORs	Other Operating Revenues
OP	Ordering Paragraph
OPC	Operating Plan Committee
OPS	Online Pipeline Simulator
ORA	Office of Ratepayer Advocates
OSA	Office of Safety Advocates
PABA	Portfolio Allocation Balancing Account
PAC	Plant Air Compressor
PAPA	Pipeline Association for Public Awareness
PAPR	Powered Air Purifying Respirator
PCIA	Portfolio Charge Indifference Adjustment
PCT	Programmable Communicating Thermostat
PDP	Peak-Day Pricing
PDR	Proxy Demand Response
Pension	PG&E's Defined Benefit Retirement
PET	Project Estimating Tool
PEV	Plug-In Electric Vehicles
PFM	Petition for Modification
PG&E	Pacific Gas and Electric Company
PHI	Personal History Information
PHI	Protected Health Information
PHMSA	Pipeline Hazardous Materials and Safety Administration
PI	Personal Information or Process Improvement

ACRONYM	DEFINITION
PIA	Privacy Impact Assessment
PILC	Paper Insulated Lead Covered
PIPP	Percentage of Income Payment Plan
PMO	Project Management Office
PO	Process Owner
POMMS	PG&E Operational Mesoscale Modeling System
POR	Plan of Reorganization
PPP	Procurement Portfolio Planner or Personal Protective Equipment
Prop F	Proposition F
PSBA	Physical Security Balancing Account
PSEP	Pipeline Safety Enhancement Plan
PSIP	PSPS Situational Intelligence Platform
PSPS	Public Safety Power Shutoff
PSRC	Public Safety Risk Committee or Public Safety Risk Council
PSS	Public Safety Specialists
PT	Potential Transformer
PTR	Peak-Time Rebate
PTY	Post Test-Year
PTYR	Post Test-Year Ratemaking
Pub. Util. Code	Public Utilities Code
PUC	Project Unit Credit
PVRR	Present Value of Revenue Requirement
PwC UK	PWC United Kingdom
QIP	Qualified Improvement Property

ACRONYM	DEFINITION
QSL	Qualified Supplier List
R&R	Rewards And Recognition
R1	Release 1
RAM	Revenue Adjustment Mechanism
RAMP	Risk Assessment and Mitigation Phase
RBA	Rule 20 Balancing Account
RBAMA	Rate Base Adjustments Memorandum Account
RBPPF	Risk Based Portfolio Prioritization Framework
RC&PMA	Routine Compression and Processing Memorandum Account
RCAMA	Root Cause Analysis Memorandum Account
RCD	Remote Connect and Disconnect
RCG	Rosen Consulting Group
RCP	Rate Case Plan or Representative Concentration Pathway
RCPMA	Routine Compression and Processing Memorandum Account
RCV	Remote Controlled Valves
RDF	Risk Based Decision-Making Framework
RDRR	Reliability Demand Response Resource
REFCL	Rapid Earth Fault Current Limiter
RFI	Request For Information
RFP	Request For Proposal
RFW	Red Flag Warning
RIBA	Risk Informed Budget Allowance
Risk OIR	Risk-Based Decision-Making Framework Order Instituting Rulemaking
RMC	Risk Management Community

ACRONYM	DEFINITION
RMS	Risk Maturity Score
RNG	Renewable Natural Gas
RO	Results Of Operations
ROE	Return On Equity
RP	Recommended Practice
RSAR	Risk Spending Accountability Reporting
RSE	Risk Spend Efficiency
RT	Real-Time
RT SCADA	Real-Time Supervisory Control and Data Acquisition
RTBA	Risk Transfer Balancing Account
RTP	Real-Time Pricing
RVPs	Regional Vice Presidents
SAF	Service Adoption Framework
SAFe	Scaled Agile Framework
SAP	System Automation and Protection
SAR	Spending Accountability Reports
SB	Senate Bill
SBA	SBA Communications Corporation
SBE	Small Business Engagement
SCADA	Supervisory Control and Data Acquisition
SCC	Stress Corrosion Cracking
SCCDA	Stress Corrosion Cracking Direct Assessment
SCE	Southern California Edison Company
SCEC	Southern California Earthquake Center

ACRONYM	DEFINITION
SoCalGas	Southern California Gas Company
SDG&E	San Diego Gas & Electric Company
SDS	Strategic Data Science
SEC	Securities and Exchange Commission
SED	Safety and Enforcement Division
SEIU	Service Employee International Union
SERA	System Earthquake Risk Assessment
SERP	Supplemental Executive Retirement Plan
SF HCSO	San Francisco Health Care Security Ordinance
SFBA	San Francisco Bay Area
SFGO	San Francisco General Office
SFGTSA	Shareholder-Funded Gas Transmission Safety Account
SHPE	Society of Hispanic Professional Engineers
SI	Supplemental Inspection
SIF	Serious Injury or Fatality
SIMI	Settlement Information and Market Implementation
Simplified RSE	Simplified Wildfire Risk Spend Efficiency
SIPT	Safety and Infrastructure Protection Team
SIQ	Sensor IQ™
S-MAP	Safety Model Assessment Proceeding
SMU	SmartMeter™ Upgrade
SoCalGas	Southern California Gas Company
SOM	Safety and Operational Metrics
SONP	Shut-Off For Non-Payment

ACRONYM	DEFINITION
SOX	Sarbanes Oxley
SP U-R	CPUC Standard Practice U4
SPD	Safety Policy Division
SPD Report	November 25, 2020 Report issued by SPD
SPR	Simulated Plant Record
SPS	Standalone Power System
SQC	Safety, Quality, and Contract Management Program
SRC	Specification Review Committee
SRSP	Supplemental Retirement Savings Plan
SRTC	San Ramon Technology Center
SRVCC	San Ramon Valley Conference Center
SST	Sustainable Solutions Turnkey
SSWC	Selective Seam Weld Corrosion
ST	Straight Time
STAGE	Statistically Aged
STARS	An alliance of southwestern nuclear facilities
STD	Short-Term Disability
STEM	Science, Technology, Engineering, and Math
STIP	Short-Term Incentive Plan
SUP	Special Use Permit
SVL	Statistical Value of Life
SWE	Society of Women Engineers
SWGR	Switch Gear
Talent	Talent Acquisition and Internal Mobility

ACRONYM	DEFINITION
TAM	Technical Advice Memorandum
TAP	Technical Assistance Program
TAT	Tree Assessment Tool
TCM	Telephonic Case Management
TE	Transportation Electrification
TEBA	Transportation Electrification Balancing Account
TG	Temporary Generation
TGP	Tennessee Gas Pipeline Company, LLC
The Unions	IBEW Local 1245, ESC Local 20, And The SEIU
TIMPBA	Transmission Integrity Management Program Balancing Account
TIMPMA	Transmission Integrity Management Program Memorandum Account
TLE	Transformer Life Extension
TMA	Tax Memorandum Account
TMA-E	Tax Memorandum Account-Electric
TMA-G	Tax Memorandum Account-Gas
TOU	Time Of Use
TPRM	Third Party Risk Management
TSR	Third-Party Security Review
TURN	The Utility Reform Network
TVC	Traceable, verifiable, and complete
TY	Test Year
U.S.	United States
UAM	Underground Asset Management
UCC	Unbundled Cost Category

ACRONYM	DEFINITION
UCIS	Utility Cost Information Service
UCLA	University of California, Los Angeles
UESC	Utility Energy Services Contract
UG	Underground
UGS	Underground Systems
Underground COE	Underground Critical Operating Equipment Program
UOG	Utility-Owned Generation
UoP	Units Of Production
USIT	Ultrasonic Imaging Tool
USNRC	United States Nuclear Regulatory Commission
UTD	Utilization Technology Development
VFR	Visual Flight Rules
VM	Vegetation Management
VMBA	Vegetation Management Balancing Account
VMMA	Vegetation Management Memorandum Account
Volt/VAR	Volt/Volt-Ampere Reactive
VP	Vice President
WDRM	Wildfire Distribution Risk Model
WELL	Well Integrity Management Plan
WFE	Wildfire Feasibility Efficiency
WFGC	Wildfire Governance Committee
WFR	Work, Finance, and Resource
WIV	Wildfire Incident Viewer
WM&BD	Wholesale Marketing and Business Development Department

ACRONYM	DEFINITION
WMBA	Wildfire Mitigation Balancing Account
WMM	Wildfire Mitigation Maturity Model
WMMA	Wildfire Mitigation Memorandum Account
WMP	Wildfire Mitigation Plan
WMPMA	Wildfire Mitigation Plan Memorandum Account
WP	Workpapers
WRGSC	Wildfire Risk Governance Steering Committee
WRO	Work At The Request Of Others
WSD	Wildfire Safety Division
WSIP	Wildfire Safety Inspection Program
WSP	Wildfire Safety Program
WTW	Willis Towers Watson
WUI	Wildland Urban Interface
WV	Work Verification
XLPE	cross-linked polyethylene
ZFMA	Z-Factor Memorandum Account

17.2 Major Work Categories and Maintenance Activity Type Codes

EXPENSE CODE	DEFINITION
34	Maint Gas Trans-Subsid
AB	Misc Expense
AH	Maint Gas Storage Fac
AK	Manage Environmental Oper
AR	Read & Investigate Meters

EXPENSE CODE	DEFINITION
AT	Research & Development
AX	Maint Resv, Dams & Waterways
AY	Habitat and Species Protection
BA	E Dist Operate System
BC	Perf Reimburs Wk for Oth
BF	E T&D Patrol/Insp
BH	E Dist Routine Emergency
BI	Maint Buildings
BK	Maint Other Equip
BP	Manage DCPD Business
BQ	DCPD Support Services
BR	Operate DCPD Plant
BS	Maintain DCPD Plant Assets
BT	Nuclear Generation Fees
BV	Maintain DCPD Plant Configurtn
CM	GT Operate System
CR	Mnge Waste Disp & Transp
CT	Acq & Manage Elect Supply
CV	Acq & Manage Gas Supply
CX	GT Marketing/Sales/Strategy
CY	Manage Electric Grid Ops
DD	Provide Field Service
DE	G Dist Leak Survey
DF	G&E T&D Locate and Mark

EXPENSE CODE	DEFINITION
DG	G Dist Cathodic Protection
DK	Manage Customer Inquiries
DN	Develop & Provide Training
EL	Develop New Revenue
EO	Provide Nuclear Support
EP	Manage Property & Bldgs
ES	Implement Environment Projects
EV	Manage Service Inquiries
EW	E TD WRO
EX	G Dist Meter Protection
EY	Change/Maint Used Elec Meter
EZ	Manage Var Cust Care Processes
FG	G Dist Operate System
FH	G Dist Preventive Maint
FI	G Dist Corrective Maint
FK	Retain & Grow Customers
FL	Safety Engineering & OSHA Cmpl
FZ	E Dist Planning & Ops Engineer
GA	E T&D Maint OH Poles
GC	E Dist Subst O&M
GE	E Dist Mapping
GF	Gas Trans & Dist Sys Mapping
GG	Gas Trans & Dist Sys Modeling
GJ	Gas Transmission Mitigate Corr

EXPENSE CODE	DEFINITION
GM	Manage Energy Efficiency-NonBA
GZ	R&D Non-Balancing Account
HG	Elec Trans Ops Engr & Tech
HN	E Dist Tree Trim Bal Acct
HP	CGT Balancing Accounts
HX	E T&D Automation & Protection
HY	Change/Maint Used Gas Meters
IF	E Dist Major Emergency
IG	Manage Var Bal Acct Processes
IS	Bill Customers
IT	Manage Credit
IU	Collect Revenue
IV	Provide Account Services
JE	Manage Land Services
JH	Implement Real Estate Strategy
JK	Manage Environ Remed (Earning)
JL	Procure Materials & Services
JO	GT Pipeline Maintenance
JP	GT Station Maintenance
JQ	G Dist Integrity Mgt (Non Bal)
JT	GT Reliability & General Maint
JV	Maintain IT Apps & Infra
KA	E Dist Maint OH General
KB	E Dist Maint UG

EXPENSE CODE	DEFINITION
KC	E Dist Maint Network
KG	Operate Hydro Generation
KH	Maint Hydro Generating Equip
KI	Maint Hydro Bldg, Grnd,Infrast
KJ	License Compliance Hydro Gen
KK	Operate Fossil Generation
KL	Maint Fossil Generating Equip
KM	Maint Fossil Bldg, Grnd, Infrast
KQ	Operate Alternative Gen
KR	Maint AltGen Generating Equip
KS	Maint AltGen Bldg,Grnd,Infrast
KX	Prov Human Resource Svcs
KY	Prov Regulation Svcs
KZ	Prov Risk/Security Svcs
LJ	Prov Corp Affairs Svcs
LK	G Dist WRO - Maintenance
LV	GTS Station Assessments-BA
LX	Catastrophic Events
OM	Operational Management
OS	Operational Support
ZC	Corporate Items

CAPITAL CODE	DEFINITION
04	Fleet / Auto Equip
05	Tools & Equipment
06	E Dist Line Capacity
07	E Dist Inst/Repl OH Poles
08	E Dist Replace OH Asset
09	E Dist Automation & Protection
10	E Dist WRO General
11	Relicensing Hydro Gen
12	Implement Environment Projects
12	Implement Environment Projects
14	G Dist Pipeline Repl Program
16	E Dist Customer Connects
17	E Dist Routine Emergency
20	DCPP Capital
22	Maintain Buildings
23	Implement Real Estate Strategy
25	Install New Electric Meters
25	Install New Electric Meters
26	GT Customer Connects
27	Gas Meter Protection-Capital
28	EV - Station Infrastructure
29	G Dist Customer Connects
30	E Dist WRO Rule 20A
31	NGV - Station Infrastructure

CAPITAL CODE	DEFINITION
44	Gas Capital:GasTrans-Sub
46	E Dist Subst Capacity
47	G Dist Capacity
48	E Dist Subst Repl Other Equip
49	E Dist Reliability Ckt/Zone
50	G Dist Reliability General
51	G Dist WRO
52	G Dist Leak Repl/Emergency
54	E Dist Subst Repl Transformer
56	E Dist Replace UG Asset-Gen
58	E Dist Repl Substation Safety
59	E Dist Subst Emergency Repl
63	E T&D Control System/ Facility
73	GT Pipeline Capacity
74	Install New Gas Meters
75	GT Pipeline Reliability
76	GT Station Reliability
82	TO-EGI/WRO/SI
83	GT WRO
84	GT Gas Gathering System Manage
95	E Dist Major Emergency
98	GT Integrity Management
2A	E Dist Inst/Repl OH General
2B	E Dist Inst/Repl UG

CAPITAL CODE	DEFINITION
2C	E Dist Inst/Repl Network
2F	Build IT Apps & Infra
2K	G Dist Repl/Convert Cust HPR
2L	Instl/Rpl for Hydro Safety&Reg
2M	Instal/Repl Hydro Gneratng Eqp
2N	Instal/Repl Resv,Dams&Waterway
2P	Instl/Repl Hydr BldgGrndInfrst
2S	Instal/Repl Fosil Gneratng Eqp
2T	Instl/Repl Fosl BldgGrndInfrst
3A	Instl/Rpl for AltGen Safty&Reg
3B	Instal/Repl AltGen GneratngEqp
3H	Hydroelec Lic & Lic Conditions
3K	Gas Trans Remediate Corrosion
3L	Gas Trans Storage Wells
3M	Install/Repl Var Bal Acct
3N	Security Install/Replace
3P	Gas Leak Abatement Program
3Q	Catastrophic Events
3Q	Catastrophic Events
3R	Energy Storage Capital
4A	G Dist Ctrl Operations Assets

Appendix A

Undisputed Forecast Programs with No Recommended Test Year 2023 Disallowance

This Appendix includes a list of the forecast programs at the Major Work Category (MWC) or Maintenance Activity Type (MAT) level that are undisputed and there is no Test Year (TY) 2023 recommended disallowance or reduction. Column B refers to the location in PG&E's opening testimony where PG&E describes the program and why it is important to fund.

The amounts shown in Column E, Uncontested 2023 Forecast, represent PG&E's February 28, 2022 forecast, plus errata and concessions, for programs that parties did not contest.

In September 2022, PG&E propounded Update Testimony to update its 2023 GRC forecasts due to changes in non-labor escalation factors and capital factors based on the same indices PG&E used in its original testimony.¹ The amounts shown in Column F, Forecast with September 6, 2022 Escalation, represent PG&E's final forecast. They consist of the amounts for the programs in the "Uncontested 2023 Forecast" column adjusted to include the September 2022 escalation.²

The program forecasts that parties evaluated, and upon which their recommendations are based, are the amounts in the "Uncontested 2023 Forecast" column (Column E). Parties' review of PG&E's forecasts occurred before PG&E adjusted forecasts to include the escalation update. PG&E discusses the September 2022 escalation update in Section 13 of the Opening Brief.

For certain capital MWCs or MATs, Cal Advocates did not dispute PG&E's 2023 TY forecast but recommended that PG&E's 2021 capital forecast be replaced with either PG&E's 2021 recorded costs or Cal Advocates' projection of PG&E's 2021 recorded costs. PG&E

¹ PG&E-03, p. 1-1, lines 12-13.

² The September 6, 2022 amounts are shown in workpaper PG&E-67 at the MWC level for expense and at the MAT level for capital. PG&E is providing final forecast amounts including the September 6, 2022 escalation adjustment in this Appendix at the MAT level for certain Gas Operations and Electric Distribution expense programs. To derive the MAT level amounts including the September 2022 escalation, PG&E de-escalated the February 28, 2022 forecast, including errata and concessions, and re-escalated the base amount using the new September 2022 escalation factors.

discusses Cal Advocates' recommendations related to 2021 capital forecast and recorded amounts in Section 1.5. The MWCs and MATs that are uncontested (except for Cal Advocates' recommendation to selectively replace only certain of PG&E's 2021 capital forecast with 2021 recorded costs) are marked in this appendix with an asterisk (*) in Table A2 Capital Programs, below.

Appendix A includes four tables:

- Table A1 - Expense Programs;
- Table A2 - Capital Programs;
- Table A3 - Department Costs; and
- Table A4 - Companywide Expenses.

Table A1: Expense Programs

Col. A - Line No.	Column B - Cite to Program Information in PG&E's Opening Testimony (Feb. 28, 2022) - Exhibit and Chapter Reference	Column C - Expense Program	Column D - MWC/MAT	Column E - Uncontested 2023 Forecast (\$000s Nominal Dollars)	Column F - Forecast with September 6, 2022 Escalation (\$000s Nominal Dollars)
1	Gas Operations³				
2	PG&E-03, p. 4-25, line 21 to p. 4-26, line 27.	Gas Distribution (GD) Corrective Maintenance	FIO	\$820	\$888
3	PG&E-03, p. 4-21, line 11 to p. 4-25, line 12.	GD - Tee-Cap Replacement Program	FIR	\$2,122	\$2,297
4	PG&E-03, p. 4-12, line 11 to p. 4-25, line 12.	GD - DIMP Emergent Work	JQD	\$4,111	\$4,214
5	PG&E-03, p. 4-20, line 17 to p. 4-25, line 12.	GD - Plastics Program	JQE	\$327	\$335
6	PG&E-03, p. 4-11, line 4 to p. 4-25, line 12.	GD - DIMP Program Management	JQL	\$4,809	\$4,928
7	PG&E-03, p. 5-60, line 16 to p. 5-61, line 8.	Gas Transmission and Storage (GT&S) - LNG/CNG	GMD	\$2,542	\$2,763
8	PG&E-03, p. 5-93, line 27 to p. 5-96, line 14.	GT&S - TIMP Other	HPA	\$9,157	\$10,471
9	PG&E-03, p. 5-93, line 27 to p. 5-96, line 14.	GT&S - Integrity Management Leak Survey	HPE	\$258	\$295
10	PG&E-03, p. 5-87, line 11 to p. 5-90, line 9.	GT&S - Geo-Hazard Studies	HPS	\$2,815	\$3,218
11	PG&E-03, p. 5-93, line 1 to p. 5-95, line 20.	GT&S - Root Cause Analysis	HPT	\$2,681	\$3,066
12	PG&E-03, p. 5-134, line 3 to p. 5-136, line 10.	GT&S - Engineering Support	JT1	\$2,421	\$2,728
13	PG&E-03, p. 5-119, line 1 to p. 5-129, line 7.	GT&S - Water and Levee Crossings	JT2	\$1,305	\$1,470
14	PG&E-03, p. 5-82, line 14 to p. 5-86, line 12.	GT&S - Earthquake Fault Crossings	JT3	\$1,013	\$1,141
15	PG&E-03, p. 5-119, line 1 to p. 5-129, line 7.	GT&S - Shallow and Exposed Pipe	JT4	\$2,590	\$2,917
16	PG&E-03, p. 5-112, line 13 to p. 5-117, line 6.	GT&S - Class Location – Strength Tests	JT9	\$847	\$954

³ PG&E corrected its Gas Transmission and Storage capital and expense forecasts and Gas Distribution capital forecasts after submitting its errata testimony to correct an escalation error. Exhibit PG&E-03-ES provides PG&E's forecast including the post-rebuttal errata correction.

Table A1: Expense Programs

Col. A - Line No.	Column B - Cite to Program Information in PG&E's Opening Testimony (Feb. 28, 2022) - Exhibit and Chapter Reference	Column C - Expense Program	Column D - MWC/MAT	Column E - Uncontested 2023 Forecast (\$000s Nominal Dollars)	Column F - Forecast with September 6, 2022 Escalation (\$000s Nominal Dollars)
17	PG&E-03, p. 5-72, line 1 to p. 5-76, line 8.	GT&S - Other Pipeline Safety and Reliability Pipe Replacements	JTB	\$6,434	\$7,242
18	PG&E-03, p. 5-134, line 3 to p. 5-137, line 12.	GT&S - Pipeline Investigation	JTD	\$17,871	\$20,132
19	PG&E-03, p. 5-112, line 13 to p. 5-116, line 18.	GT&S - Class Location Studies	JTQ	\$2,057	\$2,315
20	PG&E-03, p. 5-97, line 5 to p. 5-108, line 11.	GT&S - Valve Safety and Reliability	JTR	\$1,290	\$1,454
21	PG&E-03, p. 5-87, line 11 to p. 5-91, line 9.	GT&S - Geo-Hazard Mitigations	JTT	\$120	\$135
22	PG&E-03, p. 6-87, line 1 to p. 6-90, line 7.	GD - CNG Stations Expense	GMC	\$4,416	\$4,773
23	PG&E-03, p. 6-51, line 18 to p. 6-54, line 13.	GT&S – GT Gas Quality Assessment Expense	JT8	\$2,000	\$2,253
24	PG&E-03, p. 6-71, line 1 to p. 6-73, line 11.	GT&S Facilities Integrity Management Program Risk Management	JTL	\$2,627	\$2,957
25	PG&E-03, p. 6-79, line 29 to p. 6-84, line 6.	GT& - GT Station Strength Testing Expense	JTV	\$2,146	\$2,417
26	PG&E-03, p. 6-41, line 1 to p. 6-43, line 10.	GT&S -GT Routine M&C Expense	JTW	\$4,403	\$4,963
27	PG&E-03, p. 6-73, line 12 to p. 6-78, line 11.	GT&S - ECA Phase 2 Expense	LV2	\$5,185	\$5,774
28	PG&E-03, p. 7-36, line 12 to p. 7-39, line 10.	GT&S - WELL – Engineering and Support	AH#	\$2,120	\$2,418
29	PG&E-03, p. 7-36, line 12 to p. 7-38, line 20.	GT&S- WELL Other	AH3	\$2,650	\$3,023
30	PG&E-03, p. 8-26, line 13 to p. 8-28, line 24.	GD – Pilot Relight	DDD	\$12,142	\$12,199
31	PG&E-03, p. 8--26, line 13 to p. 8-29, line 17.	GD – Appliance Adjustment	DDE	\$1,150	\$1,156
32	PG&E-03, p. 8--26, line 13 to p. 8-30, line 6.	GD – Gas Fumigation Activity	DDF	\$3,587	\$3,604
33	PG&E-03, p. 8--26, line 13 to p. 8-30, line 23.	GD – Gas Leaks and Emergencies	DDG	\$31,329	\$31,475
34	PG&E-03, p. 8--26, line 13 to p. 8-31, line 11.	GD – Gas Start	DDK	\$5,130	\$5,154
35	PG&E-03, p.8 -26, line 13 to p. 8-31, line 28.	GD – Gas Stop	DDL	\$4,584	\$4,605
36	PG&E-03, p. 8-10, line 15 to p. 8-19, line 4.	GD – Locate and Mark Other	DF#	\$2,162	\$2,192
37	PG&E-03, p. 8-29, line 5 to p. 8-26, line12	GD – Preventative and Corrective Maintenance, Other	FH#	\$1,173	\$1,246
38	PG&E-03, p. 8-33, line 12 to p. 8-36, line 23.	GD – Routine Maintenance on Mains and Services	FHA	\$2,763	\$2,935

Table A1: Expense Programs

Col. A - Line No.	Column B - Cite to Program Information in PG&E's Opening Testimony (Feb. 28, 2022) - Exhibit and Chapter Reference	Column C - Expense Program	Column D - MWC/MAT	Column E - Uncontested 2023 Forecast (\$000s Nominal Dollars)	Column F - Forecast with September 6, 2022 Escalation (\$000s Nominal Dollars)
39	PG&E-03, p. 8-19, line 5 to p. 8-22, line 7.	GD – Regulatory Station Preventative Maintenance (PM)	FHB	\$4,994	\$5,305
40	PG&E-03, p. 8-19, line 5 to p. 8-23, line 5.	GD – Farm Tap PM	FHC	\$409	\$434
41	PG&E-03, p. 8-33, line 12 to p. 8-37, line 16.	GD – Routine Maintenance on Services	FHE	\$4,652	\$4,942
42	PG&E-03, p. 8-19, line 5 to p. 8-24, line 13.	GD – Valve PM	FHG	\$2,422	\$2,573
43	PG&E-03, p. 8-33, line 12 to p. 8-38, line 6.	GD – Service Valve Replacement or Repair	FHI	\$7,999	\$8,497
44	PG&E-03, p. 8-33, line 12 to p.8-38, line 18.	GD – Non-Recurring Projects	FHJ	\$3,758	\$3,992
45	PG&E-03, p. 8-19, line 5 to p. 8-25, line 14.	GD – PM SCADA	FHO	\$1,453	\$1,543
46	PG&E-03, p. 8-19, line 5 to p. 8-25, line 28.	GD – CM SCADA	FHP	\$752	\$798
47	PG&E-03, p. 8-40, line 1 to p. 8-41, line 7.	GD – Distribution Pipeline Markers	FHR	\$1,793	\$2,071
48	PG&E-03, p. 8-19, line 5 to p. 8-22, line 13.	GD – Regulator Station Corrective Maintenance (CM)	FIB	\$2,272	\$2,322
49	PG&E-03, p. 8-19, line 5 to p. 8-23, line 23.	GD – Farm Tap CM	FIC	\$983	\$1,004
50	PG&E-03, p. 8-19, line 5 to p. 8-24, line 26.	GD – Valve CM	FIF	\$390	\$399
51	PG&E-03, p. 8-26, line 13 to p. 8-32, line 18.	GD – Atmospheric Corrosion Remediation	HYI	\$919	\$922
52	PG&E-03, p. 8-10, line 15 to p. 8-18, line 20.	GD – Dig-In Reduction Team	JQC	\$3,509	\$3,658
53	PG&E-03, p. 8-46, line 7 to p. 8-47, line 8.	GT&S – Locate and Mark	DFA	\$1,329	\$1,544
54	PG&E-03, p. 8-52, line 7 to p. 8-60, line 9.	GT&S – PM SCADA	JO1	\$337	\$361
55	PG&E-03, p. 8-52, line 7 to p. 8-60, line 24.	GT&S – CM SCADA	JO2	\$243	\$260
56	PG&E-03, p. 8-48, line 10 to p.8-52, line 6.	GT&S – Ground Patrol	JOF	\$1,002	\$1,072
57	PG&E-03, p. 8-52, line 7 to p. 8-55, line 10.	GT&S – PM Regulator Station	JOG	\$3,825	\$4,092
58	PG&E-03, p. 8-52, line 7 to p. 8-56, line 14.	GT&S – PM Manual Valve	JOH	\$1,446	\$1,546
59	PG&E-03, p. 8-52, line 7 to p. 8-57, line 13.	GT&S – PM Automated Valve and Actuators	JOI	\$38	\$41
60	PG&E-03, p. 8-52, line 7 to p. 8-58, line 17.	GT&S – Gas Holders PM/CM	JOJ	\$122	\$131
61	PG&E-03, p. 8-52, line 7 to p. 8-61, line 10.	GT&S – Operate Transmission Pipelines	JOK	\$707	\$756
62	PG&E-03, p. 8-52, line 7 to p. 8-61, line 23.	GT&S – Operate Transmission Regulator Station	JOL	\$446	\$477
63	PG&E-03, p. 8-52, line 7 to p. 8-55, line 25.	GT&S – CM Regulator Station	JOM	\$1,080	\$1,156
64	PG&E-03, p. 8-52, line 7 to p. 8-56, line 28.	GT&S – CM Manual Valve	JON	\$918	\$982

Table A1: Expense Programs

Col. A - Line No.	Column B - Cite to Program Information in PG&E's Opening Testimony (Feb. 28, 2022) - Exhibit and Chapter Reference	Column C - Expense Program	Column D - MWC/MAT	Column E - Uncontested 2023 Forecast (\$000s Nominal Dollars)	Column F - Forecast with September 6, 2022 Escalation (\$000s Nominal Dollars)
65	PG&E-03, p. 8-52, line 7 to p. 8-57, line 29.	GT&S – CM Automated Valve ad Actuators	JOO	\$215	\$230
66	PG&E-03, p. 8-70, line 12 to p. 8-73, line 8.	GT&S – Pipeline Marker Maintenance	JOS	\$1,703	\$1,823
67	PG&E-03, p. 8-70, line 12 to p. 8-73, line 22.	GT&S – Routine Weed Abatement	JOT	\$1,471	\$1,574
68	PG&E-03, p. 8-48, line 10 to p. 8-51, line 19.	GT&S – Aerial Patrol	JOV	\$4,662	\$4,988
69	PG&E-03, p. 8-52, line 7 to p. 8-59, line 7.	GT&S – PM Meter and Chromatographs	JOX	\$1,884	\$2,016
70	PG&E-03, p. 8-52, line 7 to p. 8-59, line 23.	GT&S - CM Meter and Chromatographs	JOY	\$279	\$299
71	PG&E-03, p. 8-61, line 24 to p. 8-64, line 7.	GT&S – PM Station Piping Outside Compressor Station	JPA	\$946	\$1,016
72	PG&E-03, p. 8-61, line 24 to p. 8-64, line 23.	GT&S - CM Station Piping Outside Compressor Station	JPB	\$457	\$490
73	PG&E-03, p. 8-61, line 24 to p. 8-65, line 6.	GT&S – PM Gas Processing Equipment	JPC	\$1,853	\$1,989
74	PG&E-03, p. 8-61, line 24 to p. 8-66, line 4.	GT&S – PM Inside Compressor Station	JPD	\$1,747	\$1,875
75	PG&E-03, p. 8-61, line 24 to p. 8-67, line 5.	GT&S – PM Storage Compressor Station Support	JPE	\$2,201	\$2,362
76	PG&E-03, p. 8-61, line 24 to p. 8-65, line 18.	GT&S -CM Gas Processing Equipment	JPG	\$949	\$1,019
77	PG&E-03, p. 8-61, line 24 to p. 8-66, line 17.	GT&S – CM Inside Compressor Statin	JPH	\$1,999	\$2,146
78	PG&E-03, p. 8-61, line 24 to p. 8-67, line 20.	GT&S – CM Storage Compressor Station Support	JPI	\$1,472	\$1,580
79	PG&E-03, p. 8-61, line 24 to p. 8-68, line 3.	GT&S – PM Power Units	JPK	\$134	\$144
80	PG&E-03, p. 8-61, line 24 to p. 8-68, line 18.	GT&S – CM Power Units	JPL	\$267	\$287
81	PG&E-03, p. 8-61, line 24 to p. 8-69, line 27.	GT&S – Station Operations	JPN	\$5,817	\$6,243
82	PG&E-03, p. 8-61, line 24 to p. 8-69, line 3.	GT&S – PM Storage Wells	JPO	\$550	\$591
83	PG&E-03, p. 8-61, line 24 to p. 8-69, line 16.	GT&S – CM Storage Wells	JPP	\$78	\$84
84	PG&E-03, p. 8-61, line 24 to p. 8-70, line 11.	GT&S -Permits and Fees	JTH	\$7,443	\$8,378
85	PG&E-03, p. 8-70, line 12 to p. 8-74, line 10.	GT&S – Vegetation Management	JTK	\$15,888	\$17,899
86	PG&E-03, p. 8-70, line 12 to p. 8-74, line 25.	GT&S – Encroachments Structures and Right of Way Clean-up	JTO	\$1,190	\$1,341
87	PG&E-03, p. 9-15, lines 8-31 and p. 9-19 line 24 to p. 9-20, line 11.	GD – Cathodic Protection - Monitoring	DGA	\$4,038	\$4,343

Table A1: Expense Programs

Col. A - Line No.	Column B - Cite to Program Information in PG&E's Opening Testimony (Feb. 28, 2022) - Exhibit and Chapter Reference	Column C - Expense Program	Column D - MWC/MAT	Column E - Uncontested 2023 Forecast (\$000s Nominal Dollars)	Column F - Forecast with September 6, 2022 Escalation (\$000s Nominal Dollars)
88	PG&E-03, p. 9-16, lines 1-18 and p. 9-20, line 12 to p. 9-21, line 9.	GD – Cathodic Protection – Troubleshoot	DGB	\$4,837	\$5,201
89	PG&E-03, p. 9-17, line 28 to p. 9-18, line 5 and p. 9-22, lines 3-18.	GD – Cathodic Protection – Rectifier Maintenance	DGC	\$610	\$656
90	PG&E-03, p. 9-18, lines 6-19 and p. 9-22, line 19 to p. 9-23, line 10.	GD – Cathodic Protection – Resurvey	DGD	\$3,659	\$3,935
91	PG&E-03, p. 9-18, line 20 to p. 9-19, line 2 and p. 9-23, lines 11-27.	GD – G: Isolated Steel Service Evaluation	DGE	\$6,312	\$6,788
92	PG&E-03, p. 9-29, line 13 to p. 9-31, line 6.	GD – Install Casing Test Stations	DGG	\$3133	\$3,369
93	PG&E-03, p. 9-29, line 13 to p. 9-31, line 21.	GD – Casing Mitigate <100'	DGH	\$4,110	\$4,420
94	PG&E-03, p. 9-25, line 6 to p. 9-26, line 26.	GD – Corrosion AC Inspections	FHK	\$143	\$148
95	PG&E-03, p. 9-25, line 6 to p. 9-26, line 5 and p. 9-28, line 20 to p. 9-29, line 12.	GD – Atmospheric Corrosion Regulator Station Repairs	FHN	\$1,032	\$1,070
96	PG&E-03, p. 9-17, lines 9-27 and p. 9-21, line 10 to p. 9-22, line 2.	GD – Maintain Corr-G Cathodic Protection	FII	\$5,997	\$6,473
97	PG&E-03, p. 9-53 line 1 to p. 9-55, line 6.	GT&S – Electric Interference - AC	GJA	\$1,442	\$1,640
98	PG&E-03, p. 9-43, line 18 to p. 9-45, line 11.	GT&S – Atmospheric Corrosion	GJB	\$3,598	\$4,093
99	PG&E-03, p. 9-39, line 16 to p. 9-42, line 2.	GT&S – Cathodic Protection Expense	GJC	\$388	\$442
100	PG&E-03, p. 9-67, line 12 to p. 9-68, line 17.	GT&S – Test Stations	GJD	\$231	\$263
101	PG&E-03, p. 9-57, line 3 to p. 9-58, line 15	GT&S – Close Interval Survey	GJE	\$3,879	\$4,413
102	PG&E-03, p. 9-50, line 12 to p. 9-52, line 3.	GT&S – Electrical Interference – DC	GJF	\$751	\$854
103	PG&E-03, p. 9-58, line 16 to p. 9-63, line 14.	GT&S – Internal Corrosion	GJH	\$5,681	\$6,462
104	PG&E-03, p. 9-65, line 1 to p. 9-67, line 11.	GT&S – Low Read Investigations	GJJ	\$272	\$310
105	PG&E-03, p. 9-65, line 1 to p. 9-66, line 16.	GT&S – Corrosion Support	GJK	\$2,683	\$3,053
106	PG&E-03, p. 9-46, line 12 to p. 9-49, line 4.	GT&S – Casings	GJM	\$4,005	\$4,556
107	PG&E-03, p. 9-33, line 4 to p. 9-37, line 6.	GT&S – Cathodic Protection Rectifier Maintenance	JOA	\$114	\$122
108	PG&E-03, p. 9-33, line 4 to p. 9-37, line 22.	GT&S – Cathodic Protection Monitoring	JOB	\$1,247	\$1,334
109	PG&E-03, p. 9-33, line 4 to p. 9-38, line 11.	GT&S – Cathodic Protection Troubleshoot	JOC	\$786	\$841

Table A1: Expense Programs

Col. A - Line No.	Column B - Cite to Program Information in PG&E's Opening Testimony (Feb. 28, 2022) - Exhibit and Chapter Reference	Column C - Expense Program	Column D - MWC/MAT	Column E - Uncontested 2023 Forecast (\$000s Nominal Dollars)	Column F - Forecast with September 6, 2022 Escalation (\$000s Nominal Dollars)
110	PG&E-03, p. 9-33, line 4 to p. 9-38, line26.	GT&S – Cathodic Protection Corrective Maintenance	JOQ	\$346	\$370
111	PG&E-03, p. 9-33, line 4 to p. 9-39, line 15.	GT&S – Atmospheric Corrosion Inspection	JOZ	\$484	\$517
112	PG&E-03, p. 10-8, line 24 to p. 10-14, line22.	GD – Downgrade No Repair	DEC	\$3,376	\$3,659
113	PG&E-03, p. 10-8, line 24 to p. 10-17, line 6.	GD – Leak Survey Support	DE#	\$2,911	\$3,282
114	PG&E-03, p. 10-8, line 24 to p. 10-12, line 14.	GD – Leak Survey	DEA	\$9,878	\$10,707
115	PG&E-03, p. 10-8, line 24 to p.10-14, line 3.	GD – Special Leak Survey	DEB	\$2,693	\$2,919
116	PG&E-03, p. 10-8, line 24 to p. 10-15, line 8.	GD – Rechecks	DED	\$2,455	\$2,662
117	PG&E-03, p. 10-8, line 24 to p. 10-15, line22.	GD – Customer Calls	DEE	\$756	\$820
118	PG&E-03, p. 10-8, line 24 to p. 10-16, line 15.	GD – Advanced Mobile Technology	DEF	\$11,881	\$12,878
119	PG&E-03, p. 10-25, line 1 to p. 10-31, line 18.	GD – Leak Repair Support	FI#	\$3,986	\$4,351
120	PG&E-03, p. 10-25, line 1 to p. 10-28, line 18	GD – Maint-Corr Gas Service Leak, Above Ground	FIH	\$3,936	\$4,303
121	PG&E-03, p. 10-25, line 1 to p. 10-32, line 10.	GD -Maint-Corr Gas Main Dig-in	FIJ	\$957	\$1,044
122	PG&E-03, p. 10-25, line 1 to p. 10-32, line 10.	GD - Maint-Corr Gas Service Dig-in	FIK	\$1,533	\$1,674
123	PG&E-03, p. 10-25, line 1 to p. 10-32, line 28	GD – Major Event Distribution Gas	FIM	\$471	\$514
124	PG&E-03, p. 10-25, line 1 to p. 10-29, line 18.	GD – Maint-Corr Gas Service Leak, Below Ground	FIP	\$30,404	\$32,611
125	PG&E-03, p. 10-8, line 18 to p. 10-18, line 22.	GD – Atmospheric Corrosion Monitor	FIQ	\$1,303	\$1,406
126	PG&E-03, p. 10-8, line 18 to p. 10-17, line 23,	GD – DIMP Leak Survey	JQA	\$849	\$872
127	PG&E-03, p. 10-39, line 1 to p. 10-40. line 10.	GT&S – Ground Leak Survey	JOE	\$957	\$1,023
128	PG&E-03, p. 10-39, line 1 to p. 10-40. line 25.	GT&S – Leak Rechecks	JOR	\$256	\$274
129	PG&E-03, p. 10-39, line 1 to p. 10-41, line 22.	GT&S – Aerial Leak Survey	JOW	\$2,411	\$2,579
130	PG&E-03, p. 10-45, line 7 to p. 10-47, line 2.	GT&S – CARB Leak Survey	JPQ	\$3,156	\$3,387
131	PG&E-03, p. 10-45, line 7 to p. 10-47, line 21,	GT&S – CARB Leak Repairs	JPR	\$2,456	\$2,636
132	PG&E-03, p. 11-25, line 1 to p. 11-31, line 8.	GD – Capacity Uprates	DEH	\$2,338	\$2,534
133	PG&E-03, p. 11-38, line 1 to p. 11-42, line 19.	GD – Operate Distribution Gas Reg. General	FGC	\$178	\$182
134	PG&E-03, p. 11-20, line 12 to p. 11-24, line 26.	GD – Gas Distribution Portfolio Management and Engineering	GG#	\$2,519	\$2,527
135	PG&E-03, p. 11-20, line 12 to p. 11-24, line 11.	GD -Gas System Planning. GSO	GGA	\$6,913	\$6,934

Table A1: Expense Programs

Col. A- Line No.	Column B - Cite to Program Information in PG&E's Opening Testimony (Feb. 28, 2022) - Exhibit and Chapter Reference	Column C - Expense Program	Column D - MWC/MAT	Column E - Uncontested 2023 Forecast (\$000s Nominal Dollars)	Column F - Forecast with September 6, 2022 Escalation (\$000s Nominal Dollars)
136	PG&E-03, p. 11-60, line 16 to p. 11-62, line 8.	GT&S – Gill Ranch Operations and Maintenance	AH4	\$2,980	\$3,400
137	PG&E-03, p. 11-43, line 3 to p. 11-48, line 17.	GT&S – GT&S Marketing, Sales, Strategy	CXA	\$5,750	\$5,825
138	PG&E-03, p. 11-48, line 18 to p. 11-52, line 20.	GT&S – Uprates	JTM	\$939	\$1,058
139	PG&E-03, p. 12-8, line 2 to p. 12-13, line 13.	GD – ISvcs: Wrkplce End User SW Ste	JVA	\$11,388	\$12,981
140	PG&E-03, p. 12-8, line 2 to p. 12-13, line 13.	GT&S – ISvcs: Wrkplce End User SW Ste	JVA	\$2,190	\$2,546
141	PG&E-03, p. 12-8, line 2 to p. 12-13, line 13.	GD – Maintain IT Applications and Infrastructure	JV#	\$1,200	\$1,368
142	PG&E-03, p. 12-8, line 2 to p. 12-13, line 13.	GT&S - Maintain IT Applications and Infrastructure	JV#	\$800	\$930
143	PG&E-03, p. 13-27, line 5 to p. 13-29, line 18.	GD – Safety, Quality and Contract Management	AB7	\$496	\$565
144	PG&E-03, p. 13-16, line 1 to p. 13-17, line 23.	GD – Gas Qualifications	DN2	\$2,546	\$2,847
145	PG&E-03, p. 13-24, line 1 to p. 13-25, line 28.	GD Mapping Support – Distribution	GFO	\$4,203	\$4,242
146	PG&E-03, p. 13-33, line 1 to p. 13-38, line 4.	GD – Operational Management	OM#	\$13,183	\$13,408
147	PG&E-03, p. 13-33, line 1 to p. 13-38, line 4.	GD – Operational Support	OS#	\$26,990	\$27,578
148	PG&E-03, p. 13-27, line 5 to p. 13-29, line 18.	GT&S – Safety, Quality and Contract Management	AB7	\$743	\$856
149	PG&E-03, p. 13-8, line 15 to p. 13-9, line 22.	GT&S – Hazardous Waste Management	AKA	\$2,986	\$3,332
150	PG&E-03, p. 13-9, line 23 to p. 13-10, line 23.	GT&S – Hazardous Waste Disposal and Transportation	CRA	\$656	\$779
151	PG&E-03, p. 13-16, line 1 to p. 13-17, line 23.	GT&S – Gas Qualifications	DN2	\$1,804	\$2,126
152	PG&E-03, p. 13-24, line 1 to p. 13-26, line 14.	GT&S – Mapping Support – Transmission	GFP	\$5,428	\$5,875
153	PG&E-03, p. 13-33, line 1 to p. 13-38, line 4.	GT&S – Operational Management	OM	\$8,527	\$9,006
154	PG&E-03, p. 13-33, line 1 to p. 13-38, line 4.	GT&S – Operational Support	OS	\$10,253	\$10,752
155	PG&E-03, p. 14-7, line 27 to p. 14-8, line 33.	GD – Work at the Request of Others	LK#	\$177	\$200
156	PG&E-03, p. 14-7, line 27 to p. 14-8, line 33.	GD – WRO Main Relocations – G	LK7	\$1,727	\$1,914
157	PG&E-03, p. 14-7, line 27 to p. 14-8, line 33.	GD – WRO Relocation Partial Svc – G	LK8	\$1,072	\$1,281
158	PG&E-03, p. 14-7, line 27 to p. 14-8, line 33.	GD – WRO Raise Frame & Covers – G	LK9	\$529	\$581
159	PG&E-03, p. 14-7, line 27 to p. 14-8, line 33.	GD – WRO Svc Cutoff @ Prop Line – G	LKL	\$307	\$339
160	PG&E-03, p. 14-7, line 27 to p. 14-8, line 33.	GD – WRO Rule 13 G Temp Pwr < 1yr G	LKN	\$0	\$0
161	PG&E-03, p. 14-7, line 27 to p. 14-8, line 33.	GD – WRO Pothole 3rd Pty Conflict-G	LKO	\$1,137	\$1,259
162	PG&E-03, p. 14-7, line 27 to p. 14-8, line 33.	GD – WRO Gas Sup & Wk Around SF – G	LKQ	\$1,842	\$2,019

Table A1: Expense Programs

Col. A - Line No.	Column B - Cite to Program Information in PG&E's Opening Testimony (Feb. 28, 2022) - Exhibit and Chapter Reference	Column C - Expense Program	Column D - MWC/MAT	Column E - Uncontested 2023 Forecast (\$000s Nominal Dollars)	Column F - Forecast with September 6, 2022 Escalation (\$000s Nominal Dollars)
163	Total Gas Operations			\$524,364	\$563,877
164					
165	Electric Distribution⁴				
166	PG&E-04, p. 4.1-13, line 2 to p. 4.1-31, line 21.	Miscellaneous Expense	AB	\$43,416	See footnote 4
167	PG&E-04, p. 4.3-62, line 7 to p. 4.3-63, line 9.	Remote Grid, Sensor IQ, Generation Enablement and Deployment	AB#	\$7,204	See footnote 4
168	PG&E-04, p. 4.3-61, line 7 to p. 4.3-62, line 6.	Asset Health and Performance Center	FZA	\$5,500	\$5,767
169	PG&E-04, p. 4.3-49, line 4 to p. 4.3-50, line 16.	Remote Grid	KAT	\$953	\$1,128
170	PG&E-04, p. 4.3-67, line 3 to p. 4.3-68, line 3.	Manage Various Balancing Account Processes	IG	\$69,204	\$78,271
171	PG&E-04, p. 4.4-8, line 2 to p. 4.4-10, line 24.	Miscellaneous Expense	AB	\$13,460	See footnote 5
171.1	PG&E-04, p. 4.5-6, line 5 to p. 4.5-20	Manage Various Balancing Account Processes	IG	Inc. with line 170 above	Inc. with line 170 above
172	PG&E-04, p. 4.6-12, lines 2-26.	Control Center Work	BAF	\$1,749	\$1,898
173	PG&E-04, p. 4.6-12, lines 2-26.	Control Center Work	BAH	\$470	\$510
174	PG&E-04, p. 4.6-27 to p. 4.6-13, line 29.	Reprogram Devices and Engineering	FZA	Inc. with line 168 above	Inc. with line 168 above
175	PG&E-04, p. 4.6-14, lines 1-13.	Substation Support	GC2	\$833	\$904
176	PG&E-04, p. 4.6-15, line 20 to p. 4.6-18, line 14.	Customer Support Activities	IG#	Inc. with line 170 above	Inc. with line 170 above
177	PG&E-04, p. 4.6-18, line 15 to p. 4.6-19, line 11.	Other Program Support (PMO)	IG#	Inc. with line 170 above	Inc. with line 170 above
178	PG&E-04, p. 5-16, line 1 to p. 5-24, line 7.	Miscellaneous Expense	AB	\$26,451	\$29,557
179	PG&E-04, p. 6-18, line 16 to p. 6-19, line 8.	Routine Emergency – Expense	BH	\$73,678	\$78,381

⁴ Uncontested projects described Chapters 4.1-4.6 and tracked in MWC AB are listed in this Appendix. While the uncontested forecast amount is provided, the costs cannot be disaggregated so as to show the forecast with the September 6, 2022 escalation.

Table A1: Expense Programs

Col. A - Line No.	Column B - Cite to Program Information in PG&E's Opening Testimony (Feb. 28, 2022) - Exhibit and Chapter Reference	Column C - Expense Program	Column D - MWC/MAT	Column E - Uncontested 2023 Forecast (\$000s Nominal Dollars)	Column F - Forecast with September 6, 2022 Escalation (\$000s Nominal Dollars)
180	PG&E-04, p. 6-20, lines 1-14.	Major Emergency – Expense	IF	\$62,788	\$70,835
181	PG&E-04, p. 7-6, line 25 to p. 7-8, line 28.	Electric Distribution Operations Activities	BA	\$29,478	\$30,048
182	PG&E-04, p. 7-6, line 25 to p. 7-10, line 18.	Customer Field Service Work	DD	\$23,776	\$23,891
183	PG&E-04, p. 7-6, line 25 to p. 7-11, line 2.	Distribution Operations Technology	HG	\$5,392	\$5,392
184	PG&E-04, p. 8-7, lines 13-21.	Read and Investigate Meters	AR	\$10,425	\$10,450
185	PG&E-04, p. 8-7, lines 22-27.	Provide Field Service	DD	\$480	\$485
186	PG&E-04, p. 8-8, lines 1-12.	Change/Maintain Used Electric Meter	EY	\$7,734	\$9,260
187	PG&E-04, p. 8-8, lines 13-21.	Change/Maintain Used Gas Meter	HY	\$685	\$689
188	PG&E-04, p. 9-48, line 22 to p. 9-54, line 21.	Tree Mortality Work	IGI	\$69,830	\$86,549
189	PG&E-04, p. 10-23, line 2 to p. 10-28, line 26.	Overhead Patrols	BFA	\$4,630	\$5,503
190	PG&E-04, p. 10-23, line 2 to p. 10-29, line 26.	Overhead Infrared Inspections	BFC	\$2,595	\$3,084
191	PG&E-04, p. 10-23, line 2 to p. 10-30, line 13.	Overhead Line Equipment Inspections and Testing	BFG	\$2,430	\$2,888
192	PG&E-04, p. 10-23, line 2 to p. 10-31, line 28.	Underground Patrols	BFD	\$2,455	\$2,918
193	PG&E-04, p. 10-23, line 2 to p. 10-31, line 28.	Underground Inspections	BFE	\$13,319	\$15,831
194	PG&E-04, p. 10-23, line 2 to p. 10-33, line 26.	Inspection Support Costs	BFH	\$4,425	\$5,260
195	PG&E-04, p. 10-23, line 2 to p. 10-24, line 4.	Other Overhead and Underground Electric Inspections	BF3, BF4, BFF, BFJ, BFL	\$804	\$956
196	PG&E-04, p. 11-37, lines 1-14.	Distribution Line Equipment Overhauls	BKA	\$1,912	\$2,042
197	PG&E-04, p. 11-22, line 2 to p. 11-24, line 2.	Overhead Critical Operating Equipment	KAF	\$6,619	\$7,836
198	PG&E-04, p. 11-24, lines 3-28.	Streetlight Burnouts	KAH	\$1,993	\$2,359
199	PG&E-04, p. 11-22, lines 2-22.	Other MWC KA	KAC, KAD, KAK, KAM, KAO, KAQ, KAS, KAP, KA#	\$7,097	\$8,402
200	PG&E-04, p. 11-33, line 1 to p. 11-34, line 16.	Underground Notifications	KBA	\$15,967	\$18,361
201	PG&E-04, p. 11-33, line 1 to p. 11-36, line 11.	Underground Critical Operating Equipment	KBC	\$1,442	\$1,658

Table A1: Expense Programs

Col. A - Line No.	Column B - Cite to Program Information in PG&E's Opening Testimony (Feb. 28, 2022) - Exhibit and Chapter Reference	Column C - Expense Program	Column D - MWC/MAT	Column E - Uncontested 2023 Forecast (\$000s Nominal Dollars)	Column F - Forecast with September 6, 2022 Escalation (\$000s Nominal Dollars)
202	PG&E-04, p. 11-33, lines 1-19.	Other MWC KB	KBD, KBE, KBP, KBQ, KB#	\$1,530	\$1,759
203	PG&E-04, p. 12-21, line 1 to p. 12-22, line 7.	Intrusive Pole Program	GAA	\$19,310	\$23,699
204	PG&E-04, p. 12-21, line 1 to p. 12-23, line 3.	Pole Loading Program	GAC	\$20,237	\$24,837
205	PG&E-04, p. 12-21, line 1 to p. 12-23, line 15	Pole Restoration Program	GAD	\$3,924	\$4,816
206	PG&E-04, p. 12-21, line 1 to p. 12-23, line 26.	Joint Pole Credits	GA#	\$(4,712)	\$(5,055)
207	PG&E-04, p. 12-21, line 1 to p. 12-24, line 15.	Joint Utilities Coordination	GAB, GAE, GAF, GAH	\$581	\$890
208	PG&E-04, p. 14-13, lines 2-22.	Network Preventive Maintenance and Repair	KC	\$5,021	\$5,300
209	PG&E-04, p. 15-19, line 2 to p. 15-22, line 12.	Substation Preventive and Corrective Maintenance and Substation Support Activities	GC	\$50,940	\$56,977
210	PG&E-04, p. 16-8, line 13 to p. 16-10, line 24.	Electric Distribution System Automation Protection	HX	\$3,008	\$3,234
211	PG&E-04, p. 17-18, line 15 to p. 17-19, line 12.	General Engineering	FZA	\$16,696	\$17,140
212	PG&E-04, p. 17-18, line 15 to p. 17-19, line 20.	Voltage Complaint Investigations	FZB	\$645	\$663
213	PG&E-04, p. 17-18, line 15 to p. 17-19, line 26.	Transformer Reports Management	FZC	\$234	\$240
214	PG&E-04, p. 17-18, line 15 to p. 17-20, line 7.	Field Work Plans	FZD	\$848	\$870
215	PG&E-04, p. 17-18, line 15 to p. 17-20, line 12.	Troublemens Field Work	FZE	\$1,519	\$1,560
216	PG&E-04, p. 18-19, line 29 to p. 18-22, line 14.	New Business Service Inquiry	EV	\$13,878	\$13,957
217	PG&E-04, p. 18-23, line 1 to p. 18-24, line 22.	Work at the Request of Others	EW	\$10,283	\$12,854
218	PG&E-04, p. 21-12. Line 16 to p. 21-30, line 19.	Miscellaneous Expense	AB	\$14,661	\$16,428
219	PG&E-04, p. 21-12. Line 16 to p. 21-30, line 19.	Electric Transmission Operations Engineering and Technology	HG	\$15,541	\$18,999
220	PG&E-04, p. 21-12. Line 16 to p. 21-30, line 19.	Manage Various Balancing Account Processes	IG	\$3,026	\$3,295
221	PG&E-04, p. 21-12. Line 16 to p. 21-30, line 19.	Maintain IT Applications and Infrastructure	JV	\$3,309	\$2,837
222	PG&E-04, p. 22-12, lines 3-11.	Streetlight Support	IS	\$1,641	\$2,030
223	PG&E-04, p. 22-13, line 1 to p. 22-14, line 25.	Operational Management	OM	\$19,513	\$20,409
224	PG&E-04, p. 22-13, line 1 to p. 22-14, line 25.	Operational Support	OS	\$60,931	\$63,436

Table A1: Expense Programs

Col. A - Line No.	Column B - Cite to Program Information in PG&E's Opening Testimony (Feb. 28, 2022) - Exhibit and Chapter Reference	Column C - Expense Program	Column D - MWC/MAT	Column E - Uncontested 2023 Forecast (\$000s Nominal Dollars)	Column F - Forecast with September 6, 2022 Escalation (\$000s Nominal Dollars)
225	Total Electric Distribution			\$781,758	\$800,288
226					
227	Energy Supply^{5,6}				
	PG&E-05, p. 3-33 ,line 1 to p. 3-34, line 16.	Manage Environmental Operations	AK	\$2,105	\$2,427
229	PG&E-05, p. 3-33, line 1 to p. 3-34, line -16.	Provide Nuclear Support	EO	\$10	\$11
230	PG&E-05, p. 4-41, lines 9-14.	Manage Environmental Operations	AK	\$2,807	\$3,173
231	PG&E-05, p. 5-45, line 20 to p. 5-46, line 12.	Operate Fossil Generation	KK	\$14,314	\$15,614
232	PG&E-05, p. 5-47, line 12 to p. 5-51, line 9.	Maintain Fossil Generating Equipment	KL	\$29,543	\$34,463
	PG&E-05, p. 5-47, line 12 to p. 5-51, line 19.	Maintain Fossil Building	KM	\$3,045	\$3,604
	PG&E-05, p. 5-45, line 20 to p. 5-47, line 11.	Operate Alternative Generation	KQ	\$467	\$502
233	PG&E-05, p. 5-47, line 12 to p. 5-52, line 11.	Maintain AltGen Generating Equipment	KR	\$1,268	\$1,439
234	PG&E-05, p. 5-47, line 12 to p. 5-53, line 4	Maintain AltGen Buildings	KS	\$521	\$615
235	PG&E-05, p. 5-54, lines 1-13.	Operational Management	OM	\$293	\$297
236	PG&E-05, p. 5-54, lines 1-13.	Operational Support	OS		
237	PG&E-05, p. 6-33, lines 6-12.	Miscellaneous Expense	AB	\$801	\$832
238	PG&E-05, p. 6-33, lines 13-17.	Acquire and Manage Electric Supply	CT	\$30,320	\$30,374
239	PG&E-05, p. 6-34, lines 8-15.	Manage Electric Grid Operations	CY	\$10,220	\$10,863
240	PG&E-05, p. 7-15, line 14 to p. 7-18, line 10.	Maintain IT Applications and Infrastructure	JV	\$2,793	\$2,960
241	Total Energy Supply			\$98,507	\$107,174

⁵ TURN made certain recommendations to reduce Nuclear Operations expense (see PG&E-18, Ch. 3) and Hydro Operations (see PG&E-18, Ch. 4) forecasts that were not ascribed to a specific MWC. PG&E has included those MWCs that are unrelated to TURN's recommended reductions.

⁶ The list of uncontested items does not reflect the agreement reached between PG&E and TURN reflecting a complete resolution of disputed Energy Supply issues between PG&E and TURN included in Appendix E.

Table A1: Expense Programs

Col. A - Line No.	Column B - Cite to Program Information in PG&E's Opening Testimony (Feb. 28, 2022) - Exhibit and Chapter Reference	Column C - Expense Program	Column D - MWC/MAT	Column E - Uncontested 2023 Forecast (\$000s Nominal Dollars)	Column F - Forecast with September 6, 2022 Escalation (\$000s Nominal Dollars)
242					
243	Customer and Communications				
244	PG&E-06E, p. 2-25, lines 3-7.	Manage Customer Inquiries	DK	\$1,895	\$1,909
245	PG&E-06E, p. 2-25, line 22 to p. 2-26, line 2.	Manage Various Customer Care Processes	EZ	\$3,786	\$3,856
246	PG&E-06E, p. 2-25, lines 12-16.	Retain and Grow Customers	FK	\$736	\$738
247	PG&E-06E, p. 2-26, lines 9-12.	Manage Energy Efficiency Non-Balancing Account	GM	\$3,547	\$3,669
248	PG&E-06E, p. 2-24, line 24 to p. 2-25, line 2.	Provide Account Services	IV	\$17,628	\$17,890
249	PG&E-06E, p. 3-22, line 18 to p. 3-23, line 6.	Manage Various Customer Care Processes	EZ	\$15,438	\$16,017
250	PG&E-06E, p. 3-23, lines 8-14.	Manage Energy Efficiency Non-Balancing Account	GM	\$7,415	\$7,835
251	PG&E-06E, p. 4-7, line 11 to p. 4-8, line 11.	Manage Customer Inquiries	DK	\$60,166	\$60,345
252	PG&E-06E, p. 4-8, line 12 to p. 4-9, line 18.	Manage Various Customer Care Processes	EZ	\$7,362	\$7,625
253	PG&E-06E, p. 6-10, line 23 to p. 6-11, line 2.	Read and Investigate Meters	AR	\$(241)	\$(110)
254	PG&E-06E, p. 6-11, lines 3-8.	Manage Various Customer Care Processes	EZ	\$1,852	\$1,924
255	PG&E-06E, p. 6-11, lines 9-16.	Bill Customers	IS	\$48,517	\$50,043
256	PG&E-06E, p. 6-11, lines 17-22.	Manage Credit	IT	\$14,648	\$15,023
257	PG&E-06E, p. 6-11, lines 23-27.	Collect Revenue	IU	\$8,740	\$8,995
258	PG&E-06E, p. 7-10, lines 12-15.	Change/Maintain Used Electric Meters	EY	\$892	\$902
259	PG&E-06E, p. 7-10, lines 16-19.	Manage Various Customer Care Processes	EZ	\$459	\$480
260	PG&E-06E, p. 7-10, lines 20-24.	Change/Maintain Used Gas Meters	HY	\$6,673	\$6,709
261	PG&E-06E, p. 8-11, line 21 to p. 8-12, line 23.	Manage Various Customer Care Processes	EZ	\$15,977	\$16,441
262	PG&E-06E, p. 11-4, line 6 to p. 11-9, line 17.	Manage Various Balancing Account Processes	IG	\$9,550	\$10,109
263	Total Customer and Communications			\$225,040	\$230,400
264					

Table A1: Expense Programs

Col. A - Line No.	Column B - Cite to Program Information in PG&E's Opening Testimony (Feb. 28, 2022) - Exhibit and Chapter Reference	Column C - Expense Program	Column D - MWC/MAT	Column E - Uncontested 2023 Forecast (\$000s Nominal Dollars)	Column F - Forecast with September 6, 2022 Escalation (\$000s Nominal Dollars)
265	Shared Services⁷				
266	PG&E-07, p. 1-49, lines 25-33.	Miscellaneous Expenses	AB	\$11,235	\$11,342
267	PG&E-07, p. 1-49, lines 15-24.	Safety Engineering & OSHA Compliance	FL	\$18,891	\$19,071
268	PG&E-07, p. 1-50, lines 9-14.	Maintain IT Applications and Infrastructure	JV	\$554	\$559
269	PG&E-07, p. 1-50, lines 1-8.	Provide Human Resources Services	KX	\$7,573	\$7,645
270	PG&E-07, p. 2-30, lines 4-26.	Manage DCPD Business	BP	\$1,311	\$1,340
271	PG&E-07, p. 2-30, line 27 to p. 2-31, line 16.	Maintain IT Applications and Infrastructure	JV	\$766	\$812
272	PG&E-07, p. 4-16, line 13 to p. 4-17, line 2.	Generation Supply Chain Department	JL	\$17,921	\$17,552
273	PG&E-07, p. 4-16, line 13 to p. 4-17, line 2.	Sourcing – Corporate and Shared Services	JL	Inc. with line 272 above	Inc. with line 272 above
274	PG&E-07, p. 4-16, line 13 to p. 4-17, line 2.	Sourcing – Corporate Services (Sourcing Ops)	JL	Inc. with line 272 above	Inc. with line 272 above
275	PG&E-07, p. 4-16, line 13 to p. 4-17, line 2.	Sourcing -IT	JL	Inc. with line 272 above	Inc. with line 272 above
276	PG&E-07, p. 4-16, line 13 to p. 4-17, line 2.	Supplier Diversity	JL	Inc. with line 272 above	Inc. with line 272 above
277	PG&E-07, p. 4-16, line 13 to p. 4-17, line 2.	VP Supply Chain Management	JL	Inc. with line 272 above	Inc. with line 272 above
278	PG&E-07, p. 4-16, line 13 to p. 4-17, line 2.	IT Bus. Tech Projects – Corp Svc.	JV	\$36	\$37
279	PG&E-07, p. 4-16, line 13 to p. 4-17, line 2.	Sourcing – Electric T&D	OS	\$8,878	\$8,802
280	PG&E-07, p. 4-16, line 13 to p. 4-17, line 2.	Sourcing – Gas	OS	Inc. with line 279 above	Inc. with line 279 above
281	PG&E-07, p. 4-16, line 13 to p. 4-17, line 2.	Sourcing IT	OS	Inc. with line 279 above	Inc. with line 279 above

⁷ The list of uncontested items does not reflect the settlement proposal on disputed issues discussed in Appendix F.

Table A1: Expense Programs

Col. A - Line No.	Column B - Cite to Program Information in PG&E's Opening Testimony (Feb. 28, 2022) - Exhibit and Chapter Reference	Column C - Expense Program	Column D - MWC/MAT	Column E - Uncontested 2023 Forecast (\$000s Nominal Dollars)	Column F - Forecast with September 6, 2022 Escalation (\$000s Nominal Dollars)
282	PG&E-07, p. 5-9, line 1 to p.5-10, line 24 and p. 5-35, lines 11-22.	Maintain Buildings	BI	\$5,855	\$6,158
283	PG&E-07, p. 5-14, line 12 to p. 5-26, line 29 and p. 5-36, lines 10-14.	Implement Real Estate Strategy	JH	\$6,611	\$6,953
284	PG&E-07, p. 5-36, lines 15-18.	Maintain IT Applications and Infrastructure	JV	\$16	\$17
285	PG&E-07, p. 6-33, Table 6-12.	Miscellaneous Expense	AB	\$1,403	\$1,471
286	PG&E-07, p. 6-8, line 17 to p. 6-12, line 28 and p. 6-21, line 14 to p. 6-23, line 2.	Environmental Operations	AK	\$9,456	\$10,787
287	PG&E-07, p. 6-8, line 17 to p. 6-12, line 28 and p. 6-21, line 14 to p. 6-23, line 2.	Habitat and Species Protection	AY	\$313	\$376
288	PG&E-07, p. 6-8, line 17 to p. 6-12, line 28 and p. 6-21, line 14 to p. 6-23, line 2.	Waste Disposal and Transportation	CR	\$2,118	\$2,630
289	PG&E-07, p. 6-8, line 17 to p. 6-12, line 28 and p. 6-21, line 14 to p. 6-23, line 2.	Implement Environmental Projects	ES	\$639	\$776
290	PG&E-07, p. 6-8, line 17 to p. 6-12, line 28 and p. 6-23, line 3 to p. 6-24, line 4.	Land Services	JE	\$4,248	\$4,770
291	PG&E-07, p. 6-8, line 17 to p. 6-12, line 28 and p. 6-24, line 5 to p. 6-25, line 2.	Environmental Remediation	JK	\$5,931	\$6,248
292	PG&E-07, p. 6-8, line 17 to p. 6-12, line 28 and p. 6-33, Table 6-12.	Maintain IT Applications and Infrastructure	JV	\$66	\$67
293	PG&E-07, p. 6-8, line 17 to p. 6-12, line 28 and p. 6-33, Table 6-12.	Employee Engagement	KX	\$5	\$5
294	PG&E-07, p. 6-8, line 17 to p. 6-12, line 28 and p. 6-33, Table 6-12.	Risk and Compliance	KY	\$1,461	\$1,533
295	PG&E-07, p. 6-8, line 17 to p. 6-12, line 28 and p. 6-33, Table 6-12.	Operational Management	OM	\$532	\$551
296	PG&E-07, p. 6-8, line 17 to p. 6-12, line 28 and p. 6-33, Table 6-12.	Operational Support	OS	\$2,917	\$2,947
297	PG&E-07, p. 7-21, line 2 to p. 7-23, line 21.	Maintain IT Applications and Infrastructure	JV	\$3,550	\$3,673

Table A1: Expense Programs

Col. A- Line No.	Column B - Cite to Program Information in PG&E's Opening Testimony (Feb. 28, 2022) - Exhibit and Chapter Reference	Column C - Expense Program	Column D - MWC/MAT	Column E - Uncontested 2023 Forecast (\$000s Nominal Dollars)	Column F - Forecast with September 6, 2022 Escalation (\$000s Nominal Dollars)
298	PG&E-07, p. 8-20, lines 2-14.	Operational Management	OM	\$1,406	\$1,466
300	PG&E-07, p. 8-20, lines 2-14.	Miscellaneous Support/End User Services Overhead Credit	ZC	\$(36,686)	\$(38,193)
301	PG&E-07, p. 9-34, lines 8-33.	Maintain IT Applications and Infrastructure	JV	\$32,284	\$33,337
302	PG&E-07, p. 9-34, lines 8-33	Provide Risk Security Services	KZ	\$23,869	\$25,580
303	Total Shared Services			\$133,159	\$136,972
304					
305	Human Resources				
306	PG&E-08, p. 2-15, lines 1-18.	Maintain IT Applications and Infrastructure	JV	\$288	\$300
307	Total Human Resources			\$288	\$300
308					
309	Administrative and General⁸				
310	PG&E-09, p. 2-20, lines 5-16.	Maintain IT Applications and Infrastructure	JV	\$468	\$486
311	PG&E-09, p. 3-47, line 1 to p. 3-48, line 8.	Maintain IT Applications and Infrastructure	JV	\$104	\$106
312	PG&E-09, p. 4-8, line 26 to p. 4-9, line 7.	Maintain IT Applications and Infrastructure	JV	\$225	\$225
313	PG&E-09, p. 5-11, line 1 to p. 5-12, line 24.	Maintain IT Applications and Infrastructure	JV	\$429	\$448
314	PG&E-09, p. 6-11, lines 1-17.	Maintain IT Applications and Infrastructure	JV	\$314	\$329
315	Total Administrative and General			\$1,540	\$1,594
316					

⁸ The list of uncontested items does not reflect the settlement proposal on remaining disputed issues in Appendix G..

Table A1: Expense Programs

Col. A- Line No.	Column B - Cite to Program Information in PG&E's Opening Testimony (Feb. 28, 2022) - Exhibit and Chapter Reference	Column C - Expense Program	Column D - MWC/MAT	Column E - Uncontested 2023 Forecast (\$000s Nominal Dollars)	Column F - Forecast with September 6, 2022 Escalation (\$000s Nominal Dollars)
317	Total⁹			\$1,764,656	1,842,605

⁹ Total uncontested expense amounts represent approximately 34 percent of PG&E's total expense forecast: $\$1,764,656 / \$5,131,921 = 34\%$.

Total forecast is provided in PG&E 64 and is the sum of: Table 3A-1, p. 3-1, Total Exhibit (PG&E-03); p. 3-2,

Total Exhibit (PG&E-04); p. 3-3, Total Exhibit (PG&E-05); p. 3-4, Total Exhibit (PG&E-06E); and, p. 3-5, Total Exhibit (PG&E-07).

Table A2: Capital Programs					
Col. A - Line No.	Column B - Cite to Program Information in PG&E's Opening Testimony (Feb. 28, 2022) - Exhibit and Chapter Reference	Column C -Capital Program	Col. D - MWC/MAT	Column E - Uncontested 2023 Forecast (\$000s Nominal Dollars)	Column F - Forecast with September 6, 2022 Escalation (\$000s Nominal Dollars)
1	Gas Operations¹⁰				
2	PG&E-03, p. 4-27, line 25 to p. 4-33, line 24.	Gas Distribution (GD) - Reliability Main Replacement Program	50A	\$50,612	\$56,690
3	PG&E-03, p. 4-35, line 19 to p. 4-39, line 6.	GD - Valve Program -Reliability	50E	\$5,616	\$6,291
4	PG&E-03, p. 4-36, line 9 to p. 4-39, line 6.	GD - System Reliability/Other Equipment	50F	\$474	\$531
5	PG&E-03, p. 4-36, line 16 to p. 4-39, line 6.	GD - Stub Program	50H	\$3,074	\$3,443
6	PG&E-03, p. 4-37, line 1 to p. 4-39, line 6.	GD - Deactivation Program	50I	\$8,677	\$9,720
7	PG&E-03, p. 4-25, line 21 to p. 4-27, line 24.	GD - Encroachment Program	50J	\$16,276	\$18,230
8	PG&E-03, p. 4-35, line 19 to p. 4-39, line 6.	GD - Valve Program – Installation	50R	\$5,616	\$6,291
9	PG&E-03, p. 5-69, line 22 to p. 5-70, line 21.	Gas Transmission and Storage -(GT&S) LNG/CNG	73D	\$3,959	\$5,065
10	PG&E-03, p. 5-97, line 5 to p. 5-109, line 20.	GT&S - Valve Safety and Reliability Capital	75D	\$40,903	\$52,337
11	PG&E-03, p. 5-112, line 13 to p. 5-118, line 19.	GT&S - Class Location Replacements	75H	\$7,681	\$9,828
12	PG&E-03, p. 5-97, line 5 to p. 5-112, line 12.	GT&S - Valve Automation	75I	\$21,052	\$26,937
13	PG&E-03, p. 5-87, line 11 to p. 5-92, line 21.	GT&S - Geo-Hazard Mitigations	75J	\$7,590	\$9,712
14	PG&E-03, p. 5-82, line 14 to p. 5-87, line 10.	GT&S - Earthquake Fault Crossings Capital	75L	\$12,110	\$15,496
15	PG&E-03, p. 5-50, line 16 to p. 5-66, line 2.	GT&S - Strength Testing Capital	75N	\$39,327	\$50,321
16	PG&E-03, p. 5-72, line 1 to p. 5-82, line 13.	GT&S - Other Pipeline Safety and Reliability Replacements	75O	\$30,025	\$38,419

¹⁰ PG&E corrected its Gas Transmission and Storage capital and expense forecasts and Gas Distribution capital forecasts after submitting its errata testimony to correct an escalation error. Exhibit PG&E-03-ES provides PG&E's forecast including the post-rebuttal errata correction.

Table A2: Capital Programs

Col. A - Line No.	Column B - Cite to Program Information in PG&E's Opening Testimony (Feb. 28, 2022) - Exhibit and Chapter Reference	Column C -Capital Program	Col. D - MWC/MAT	Column E - Uncontested 2023 Forecast (\$000s Nominal Dollars)	Column F - Forecast with September 6, 2022 Escalation (\$000s Nominal Dollars)
17	PG&E-03, p. 5-38, line 3 to p. 5-48, line 13.	GT&S - Direct Assessment Capital Repair	75S	\$1,556	\$1,991
18	PG&E-03, p. 5-38, line 3 to p. 5-49, line 23.	GT&S - TIMP Direct Exam-Capital Repair/Recoat	75V	\$2,042	\$2,613
19	PG&E-03, p. 5-130, line 19 to p. 5-134, line 2.	GT&S - Gas Gathering	84D	\$10,993	\$14,067
20	PG&E-03, p. 6-87, line 1 to p. 6-90, line 7.	GD - CNG Stations	31A	\$4,754	\$5,325
21	PG&E-03, p. 6-56, line 3 to p. 6-58, line 7.	GD - Regulator Station Rebuilds	50C	\$48,508	\$54,333
22	PG&E-03, p. 6-54, line 14 to p. 6-56, line 2.	GD - Regulator Station Component Replacements	50L	\$10,374	\$11,620
23	PG&E-03, p. 6-41, line 1 to p. 6-43, line 10.	GT&S – GT Routine M&C Capital	75C	\$16,485	\$21,093
24	PG&E-03, p. 6-43, line 11 to p. 6-46, line 2.	GT&S - GT M&C Simple Station Rebuilds	763	\$6,613	\$8,462
25	PG&E-03, p. 6-43, line 11 to p. 6-46, line 2.	GT&S -GT M&C Complex Station Rebuilds	764	\$42,025	\$53,773
26	PG&E-03, p. 6-18, line 11 to p. 6-21, line 3.	GT&S – GT Routine C&P Capital	76N	\$53,636	\$66,458
27	PG&E-03, p. 6-22, line 15 to p. 6-25, line 13.	GT&S – GT Electrical Upgrades –Hinkley and Topock	76P	\$5,638	\$7,215
28	PG&E-03, p. 6-73, line 12 to p. 6-78, line 11.	GT&S - ECA Phase 2 Capital	76S	\$8,808	\$11,270
29	PG&E-03, p. 6-25, line 24 to p. 6-30, line 17.	GT&S – GT Compressor Controls Upgrade	76T	\$11,031	\$13,631
30	PG&E-03, p. 6-79, line 29 to p. 6-84, line 6.	GT&S – GT Strength Testing Capital	76V	\$14,975	\$19,162
31	PG&E-03, p. 6-84, line 7 to p. 6-86, line 6.	GT&S – GT Physical Security Upgrades Capital	76Z	\$8,629	\$11,041
32	PG&E-03, p. 8-26, line 13 to p. 8-33, line 11.	GD – Regulator Replacement	74A	\$2,195	\$2,459
33	PG&E-03, p. 9-14, line 18 to p. 9-19, line 14.	GD – Improve Rel/Sys Depd G-Deep Well Aode	50P	\$17,492	\$19,592
34	PG&E-03, p. 9-58, line 16 to p. 9-64, line 14.	GT&S – Internal Corrosion	3K1*	\$12,742	\$16,137
35	PG&E-03, p. 9-53, line 1 to p. 9-56, line 9.	GT&S – Electrical Interference -AC	3K4*	\$2,936	\$3,756
36	PG&E-03, p. 9-46, line 12 to p. 9-50, line 2.	GT&S – Casing Mitigation	3K5	\$13,213	\$16,894
37	PG&E-03, p. 9-39, line 16 to p. 9-43, line 17.	GT&S – Cathodic Protection – New	3K6	\$1,470	\$1,879
38	PG&E-03, p. 9-39, line 16 to p. 9-43, line 17.	GT&S – Cathodic Protection – Replacement	3K7	\$3,732	\$4,772
39	PG&E-03, p. 9-67, line 12 to p. 9-69, line 12.	GT&S – Test Station Installation	3K8	\$116	\$149
40	PG&E-03, p. 9-50, line 12 to p. 9-52, line 26.	GT&S - Electrical Interference -DC	3K9*	\$5,587	\$7,148
41	PG&E-03, p. 9-43, line 18 to p. 9-45, line 7.	GT&S – Atmospheric Corrosion	3KA	\$292	\$373
42	PG&E-03, p. 10-25, line 1 to p. 10-34, line 21.	GD – Emergent Leaking Main Replace	50K	\$5,598	\$6,270
43	PG&E-03, p. 10-25, line 1 to p. 10-33. Line 26.	GD – Complex Gas Service Replace Leak	50M	\$1,094	\$1,225
44	PG&E-03, p. 10-25, line 1 to p 10-35, line 8.	GD – Emergency Response Gas Dig-Ins, Services	52B	\$1,307	\$1,464

Table A2: Capital Programs

Col. A - Line No.	Column B - Cite to Program Information in PG&E's Opening Testimony (Feb. 28, 2022) - Exhibit and Chapter Reference	Column C -Capital Program	Col. D - MWC/MAT	Column E - Uncontested 2023 Forecast (\$000s Nominal Dollars)	Column F - Forecast with September 6, 2022 Escalation (\$000s Nominal Dollars)
45	PG&E-03, p. 10-25, line 1 to p 10-35, line 8.	GD - Emergency Response Gas Dig-Ins, Mains	52C	\$288	\$323
46	PG&E-03, p. 11-33, line 7 to p. 11-36, line 15	GD Electronic Pressure Recording Device	4AF	\$516	\$578
47	PG&E-03, p. 11-25, line 1 to p. 11-28, line 7.	GD – Construct/Acquire New Fac-Gas-Capacity-Mains	47B	\$34,772	\$38,948
48	PG&E-03, p. 11--25, line 1 to p. 11-28, line 24.	GD - Construct/Acquire New Fac-Gas-Capacity-Regulator Stations	47C	\$5,719	\$6,406
49	PG&E-03, p. 11-25, line 1 to p. 11-29, line 17.	Cons/Acquire New Fac-Gas-Capacity-Other	47D	\$125	\$140
50	PG&E-03, p. 11-25, line 1 to p. 11-30, line 12.	GD – ERX Pressure Monitoring-6	47F	\$57	\$64
51	PG&E-03, p. 11-48, line 18 to p. 11-57, line 19.	GT&S – Capacity Betterment	73B	\$880	\$1,127
52	PG&E-03, p. 11-60, line 16 to p. 11-63, line 27.	GT&S – Gill Ranch Capital	762	\$894	\$1,143
53	PG&E-03, p. 12-8, line 2 to p. 12-15, line 2.	GD – Build IT Applications and Infrastructure	2FA	\$11,217	\$13,574
54	PG&E-03, p. 12-8, line 2 to p. 12-15, line 2,	GT&S – Build IT Applications and Infrastructure	2FA	\$11,782	\$14,258
55	PG&E-03, p. 13-14, line 1 to p. 13-15, line 29.	GD – Tools	05A	\$6,135	\$7,424
56	PG&E-03, p. 13-14, line 1 to p. 13-15, line 29.	GT&S – Tools	05A	\$3,177	\$3,845
57	PG&E-03, p. 14-10, line 11 to p. 14-12, line 32.	GD – Gas Distribution Customer Connects	29#	\$8,796	\$9,853
58	PG&E-03, p. 14-10, line 11 to p. 14-12, line 14.	GD – New Business, Gas, CIA R15 and/or R16 MLX	29D	\$27,460	\$30,758
59	PG&E-03, p. 14-16, line 10 to p. 14-19, line 5.	GD –Work at the Request of Others	51#	\$(722)	\$(809)
60	PG&E-03, p. 14-16, line 10 to p. 14-19, line 5.	GD – WRO Relocate Mn & Svcs - G	51E	\$39,219	\$43,929
61	PG&E-03, p. 14-16, line 10 to p. 14-19, line 5.	GD – WRO Svc Only Alteration - G	51F	\$10,865	\$12,169
62	PG&E-03, p. 14-16, line 10 to p. 14-19, line 5.	GD – WRO Gas Svc Cutoff at Main - G	51G	\$15,501	\$17,362
63	PG&E-03, p. 14-16, line 10 to p. 14-19, line 5.	GD – WRO Remove Idle Main >100' - G	51I	\$2,104	\$2,356
64	PG&E-03, p. 14-16, line 10 to p. 14-19, line 5.	GD – WRO Relocate CP Area/Reg Sta-G	51J	\$808	\$905
65	PG&E-03, p. 14-16, line 10 to p. 14-19, line 5.	GD – GD – WRO G CAP Proj>\$50K	51K	\$4,729	\$5,296
66	PG&E-03, p. 14-16, line 10 to p. 14-19, line 5.	GD – 3rd Party WRO Pd.on Actuals	51L	\$269	\$301
67	Total Gas Operations			\$751,424	\$903,433
68					

Table A2: Capital Programs					
Col. A - Line No.	Column B - Cite to Program Information in PG&E's Opening Testimony (Feb. 28, 2022) - Exhibit and Chapter Reference	Column C -Capital Program	Col. D - MWC/MAT	Column E - Uncontested 2023 Forecast (\$000s Nominal Dollars)	Column F - Forecast with September 6, 2022 Escalation (\$000s Nominal Dollars)
69	Electric Distribution¹¹				
70	PG&E-04, p. 4.1-31, line 22 to p. 4.1-35, line 11.	Miscellaneous Capital	21*	\$15,369	\$17,710
71	PG&E-04, p. 4.2-29, lines 13-21.	Miscellaneous Capital	21*	Inc. with line 70 above	Inc. with line 70 above
72	PG&E-04, p. 4.3-62, line 7 to p. 4.3-63, line 9.	Sensor IQ	21A	Inc. with line 70 above	Inc. with line 70 above
73	PG&E-04, p. 4.3-69, line 29 to p. 4.3-71, line 22.	Sectionalizing Devices	49H*	\$11,993	\$13,478
74	PG&E-04, p. 4.3-68, line 4 to p. 4.3-69, line 28.	Temporary Distribution Microgrids	49M*	\$0	\$0
75	PG&E-04, p. 4.3-63, line 10 to p. 4.3-64, line 17.	Rapid Earth Fault Conductor Limiter	49R*	\$17,331	\$19,576
76	PG&E-04, p. 4.3-54, line 27 to p. 4.3-56, line 4.	Single Phase Reclosers	49T*	\$2,940	\$3,321
77	PG&E-04, p. 4.5-7, line 21 to p. 4.5-21, line 28.	Build IT Applications and Infrastructure	2F	\$25,300	\$30,616
78	PG&E-04, p. 5-16, line 1 to p. 5-27, line 4.	Emergency Preparedness and Response Capital	21*	\$5,502	\$6,477
79	PG&E-04, p. 7-11, lines 4-22.	Distribution Operations Technology	63	\$4,333	\$5,243
80	PG&E-04, p. 8-9, lines 5-14.	Install New Electric Meters	25*	\$30,101	\$33,999
81	PG&E-04, p. 11-22, lines 2-22.	Other MWC 2A – Overhead Critical Operating Equipment	2AE, 2AI 2AG*	\$31,603	\$35,696
82	PG&E-04, p. 11-25, line 21 to p. 11-26, line 14.	LED Streetlight Conversions	2AH	\$7,075	\$7,992
83	PG&E-04, p. 11-30, lines 3-28.	Other MWC 2B	2BB, 2BF, 2BP	\$8,999	\$10,164
84	PG&E-04, p. 12-25, lines 1-18.	Joint Pole	07G*, 07#*		
85	PG&E-04, p. 12-36, Table 12-10.	Miscellaneous Capital	21A*	\$0	\$0
86	PG&E-04, p. 13-34, line 1 to p. 13-37, line 24.	Cable Rejuvenation and Testing	56B		
88	PG&E-04, p. 13-44, line 1 to p. 13-49, line 24.	Line Recloser Revolving Stock	49#	\$12,488	\$14,106

¹¹ Uncontested projects described Chapters 4.1-4.5 and tracked in MWC 21 are listed in this Appendix. While the uncontested forecast amount is provided, the costs cannot be disaggregated so as to show the forecast with the September 6, 2022, escalation.

Table A2: Capital Programs

Col. A - Line No.	Column B - Cite to Program Information in PG&E's Opening Testimony (Feb. 28, 2022) - Exhibit and Chapter Reference	Column C -Capital Program	Col. D - MWC/MAT	Column E - Uncontested 2023 Forecast (\$000s Nominal Dollars)	Column F - Forecast with September 6, 2022 Escalation (\$000s Nominal Dollars)
89	PG&E-04, p. 13-44, line 1 to p. 13-46, line 18.	Distribution Automation Recloser SCADA Installations	49A	\$1,841	\$2,080
90	PG&E-04, p. 13-44, line 1 to p. 13-47, line 4.	Line Recloser and Control Replacements	49B	\$4,398	\$4,967
91	PG&E-04, p. 13-44, line 1 to p. 13-49, line 17.	FLISR Program	49S	\$3,721	\$4,203
92	PG&E-04, p. 13-44, line 1 to p. 13-48, line 25.	TripSaver and Fuse Saver Devices	49T	\$1,393	\$1,573
93	PG&E-04, p. 14-13, line 23 to p. 14-16, line 7.	Network Protector Relay Replacement	2CA*	\$325	\$367
94	PG&E-04, p. 15-23, line 1 to p. 15-24, line 18.	Switchgear Replacement	48F	\$32,433	\$36,634
95	PG&E-04, p. 15-23, line 1 to p. 15-27, line 10.	Other Equipment Replacement Work	48A, 48B, 48R	\$4,220	\$4,766
96	PG&E-04, p. 15-36, line 1 to p. 15-37, line 11.	Seismic Program	58B	\$0	\$0
97	PG&E-04, p. 15-40, line 1 to p. 15-41, line 7.	Emergency Equipment Replacement	59	\$82,323	\$92,986
98	PG&E-04, p. 16-10, line 25 to p. 16-15, line 22.	Electric Distribution System Automation Protection	09	\$27,003	\$32,443
99	PG&E-04, p. 17-30, line 1 to p. 17-38, line 20.	Miscellaneous Capital	06#	\$7,131	\$8,055
100	PG&E-04, p. 17-30, line 1 to p. 17-32, line 23.	Overloaded Transformers	06B	\$8,172	\$9,231
101	PG&E-04, p. 17-30, line 1 to p. 17-33, line 7.	Circuit Reinforcement (DP) Managed	06D	\$4,481	\$5,062
102	PG&E-04, p. 17-30, line 1 to p. 17-33, line 18.	Circuit Reinforcement (PS) Managed	06E	\$23,993	\$27,101
103	PG&E-04, p. 17-30, line 1 to p. 17-34, line 4.	Voltage Complaints	06G	\$2,751	\$3,108
104	PG&E-04, p. 17-30, line 1 to p. 17-36, line 22.	Operational Capacity Projects	06I	\$6,725	\$7,596
105	PG&E-04, p. 17-30, line 1 to p. 17-37, line 13.	Power Factor Management	06K	\$1,119	\$1,264
106	PG&E-04, p. 17-30, line 1 to p. 17-38, line 7.	Enable DG Distribution Line	06P	\$1,344	\$1,518
107	PG&E-04, p. 17-21, line 11 to p. 17-28, line 15.	Electric Distribution Substation Capacity	46	\$58,082	\$65,605
108	PG&E-04, p. 18-39, line 1 to p. 18-44, line 21.	Electric Distribution Work at the Request of Others	10*	\$132,769	\$149,965
109	PG&E-04, p. 20-23, line 1 to p. 20-37, line 8.	Build IT Applications and Infrastructure	2F	\$17,987	\$21,767
110	PG&E-04, p. 20-8, line 6 to p. 20-21 line 21.	Miscellaneous Capital	21	\$1,712	\$2,072
111	PG&E-04, p. 21-12. Line 16 to p. 21-30, line 19.	Miscellaneous Capital	21	\$2,237	\$2,707
112	PG&E-04, p. 21-12. Line 16 to p. 21-30, line 19.	IT Capital	2F	\$20,369	\$24,649
113	PG&E-04, p. 22-15, line 2 to p. 22-16, line 13.	Tools and Equipment	05*	\$6,901	\$8,351
114	PG&E-04, p. 22-18, lines 1-22.	Miscellaneous Capital	21*	\$1,493	\$1,686

Table A2: Capital Programs					
Col. A - Line No.	Column B - Cite to Program Information in PG&E's Opening Testimony (Feb. 28, 2022) - Exhibit and Chapter Reference	Column C -Capital Program	Col. D - MWC/MAT	Column E - Uncontested 2023 Forecast (\$000s Nominal Dollars)	Column F - Forecast with September 6, 2022 Escalation (\$000s Nominal Dollars)
115	Total Electric Distribution			\$627,957	\$718,134
116					
117	Energy Supply, 12				
118	PG&E-05, p. 3-52, Table 3-21.	Tools and Equipment	05	\$748	\$865
119	PG&E-05, p. 4-50, lines 2-7.	Tools and Equipment	05*	\$567	\$686
120	PG&E-05, p. 4-51, lines 10-15.	Implement Environmental Projects	12*	\$425	\$493
121	PG&E-05, p. 4-75, line 22 to p. 4-76, line 10.	Catastrophic Events	3Q*	\$121	141
122	PG&E-05, p. 5-60, line 14 to p. 5-61, line 7.	Tools and Equipment	05	\$397	\$480
123	PG&E-05, p. 5-60, lines 4-8.	Install/Replace Fossil Buildings, Grounds and Infrastructure	2T	\$1,578	\$1,849
124	PG&E-05, p. 5-59, line 1 to p. 5-60, line 2.	Install/Replace for AltGen Safety and Regulatory	3A	\$7	\$8
125	PG&E-05, p. 5-55, line 10 to p. 5-58, line 31.	Install/Replace AltGen Generating Equipment	3B	\$714	\$836
126	PG&E-05, p. 7-15, line 14 to p. 7-18, line 10.	Build IT Applications and Infrastructure	2F	\$14,100	\$17,063
127	Total Energy Supply			\$18,657	\$22,421
128					
129	Customer and Communications				
130	PG&E-06E, p. 5-8, lines 14-19.	Miscellaneous Capital	21	\$100	\$121
131	PG&E-06E, p. 7-11, lines 2-6.	Tools and Equipment	05	\$100	\$121
132	Total Customer and Communications			\$200	\$242
133					
134	Shared Services				
135	PG&E-07, p. 1-50, lines 15-22.	Build IT Applications and Infrastructure	2F	\$1,000	\$1,210
136	PG&E-07, p. 2-34, lines 9-30.	Tools and Equipment	05	\$1,357	\$1,642

¹² The list of uncontested items does not reflect the agreement reached between PG&E and TURN reflecting a complete resolution of disputed Energy Supply issues between PG&E and TURN included in Appendix E.

Table A2: Capital Programs					
Col. A - Line No.	Column B - Cite to Program Information in PG&E's Opening Testimony (Feb. 28, 2022) - Exhibit and Chapter Reference	Column C -Capital Program	Col. D - MWC/MAT	Column E - Uncontested 2023 Forecast (\$000s Nominal Dollars)	Column F - Forecast with September 6, 2022 Escalation (\$000s Nominal Dollars)
137	PG&E-07, p. 2-35, lines 1-8.	Build IT Applications and Infrastructure	2F	\$1,400	\$1,694
138	PG&E-07, p. 3-12, lines 8-25.	Tools and Equipment	05	\$607	\$734
139	PG&E-07, p. 3-12, line 26 to p. 3-13, line 10.	Miscellaneous Capital	21	\$0	\$0
140	PG&E-07, p. 5-9, line 1 to p.5-10, line 24 and p. 5-37, lines 1-4.	Maintain Buildings	22	\$37,200	\$45,017
141	PG&E-07, p. 6-8, line 17 to p. 6-12, line 28 and p. 6-25, lines 7-16.	Tools and Equipment	05	\$300	\$363
142	PG&E-07, p. 6-8, line 17 to p. 6-12, line 28 and p. 6-25, line 17 to p. 6-26, line 16.	Implement Environmental Projects	12	\$7,317	\$8,855
143	PG&E-07, p. 7-27, line 1 to p 7-29, line 19.	ERIM Program	2F	\$2,000	\$2,420
144	PG&E-07, p. 9-35, lines 14-29.	Build IT Applications and Infrastructure	2F	\$29,785	\$36,044
145	PG&E-07, p. 9-35, lines 14-29.	Security/Install/Replace	3N	\$13,326	\$16,126
146	Total Shared Services			\$94,292	\$114,105
147					
148	PG&E-08, p. 6-20, lines 8-22.	Tools and Equipment	05	\$28	\$34
149	PG&E-08, p. 6-20, lines 8-22.	Maintain Buildings	22	\$972	\$1,177
150	Total Human Resources			\$1,000	\$1,211
151					
152	Administrative and General¹³				
153	PG&E-09, p. 3-47, line 1 to p. 3-48, line 8.	Build IT Applications and Infrastructure	2F	\$500	\$605
154	PG&E-09, p. 4-8, line 26 to p. 4-9, line 7.	Build IT Applications and Infrastructure	2F	\$500	\$605
155	PG&E-09, p. 5-11, line 1 to p. 5-12, line 8.	Build IT Applications and Infrastructure	2F	\$1,500	\$1,815
156	Total Administrative and General			\$2,500	\$3,025
157					

¹³ The list of uncontested items does not reflect the settlement proposal on remaining disputed issues in Appendix G.

Table A2: Capital Programs					
Col. A - Line No.	Column B - Cite to Program Information in PG&E's Opening Testimony (Feb. 28, 2022) - Exhibit and Chapter Reference	Column C -Capital Program	Col. D - MWC/MAT	Column E - Uncontested 2023 Forecast (\$000s Nominal Dollars)	Column F - Forecast with September 6, 2022 Escalation (\$000s Nominal Dollars)
176	Total ¹⁴			\$1,496,030	\$1,762,571

Table A3: Department Costs					
Col. A - Line No.	Column B - Cite to Program Information in PG&E's Opening Testimony (Feb. 28, 2022) - Exhibit and Chapter Reference	Column C - Department Costs	Column D - FERC Acct	Column E - Uncontested 2023 Forecast (\$000s Nominal Dollars)	Column F - Forecast with September 6, 2022 Escalation (\$000s Nominal Dollars)
	Administrative and General ¹⁵				
1	PG&E-09, p. 2-2, line 20 to p. 2-18, line 25.	Finance Department	920, 921, 923	\$54,441	\$55,875
3	PG&E-09, p. 4-2, line 17 to p. 4-8, line 25.	Compliance and Ethics Department	920, 921, 923	\$8,298	\$8,536
4	PG&E-09, p. 5-2, line 20 to p. 5-10, line 22.	Regulatory Affairs	920, 921, 923	\$17,323	\$17,386
5	PG&E-09, p. 6-2, line 15 to p. 6-8, line 23.	Law Department	920, 921, 923	\$46,666	\$48,129

¹⁴ Total uncontested capital amounts represent approximately 16 percent of PG&E's total capital forecast: \$1,496,030 /\$8,961,141 = 17 percent.

Total forecast is provided in PG&E-064, p. 3-9, Table 3B-1, PG&E Exhibits 3-9.

¹⁵ The list of uncontested items does not reflect the settlement proposal on remaining disputed issues in Appendix G.

Table A3: Department Costs					
Col. A - Line No.	Column B - Cite to Program Information in PG&E's Opening Testimony (Feb. 28, 2022) - Exhibit and Chapter Reference	Column C - Department Costs	Column D - FERC Acct	Column E - Uncontested 2023 Forecast (\$000s Nominal Dollars)	Column F - Forecast with September 6, 2022 Escalation (\$000s Nominal Dollars)
6	PG&E-09, p. 7-3, line 1 to p. 7-9, line 6.	PG&E Corporation and PG&E Executive Offices; and Corporate Secretary Department Costs	920, 921, 923	\$5,054	\$5,198
7	PG&E-09, p. 8-2, line 10 to p. 8-8, line 25.	Corporate Affairs	920, 921, 923	\$8,889	\$9025
8	Total¹⁶			\$140,671	\$144,149

¹⁶ Total uncontested department costs represent approximately 52 percent of PG&E's total department cost forecast: \$140,671/\$239,278 = 59%.

Total forecast is provided in PG&E 64, p. 3-18, Table 3C-1, line 11.

Table A4: Companywide Expenses

Col. A - Line No.	Column B - Cite to Program Information in PG&E's Opening Testimony (Feb. 28, 2022) - Exhibit and Chapter Reference	Column C - Companywide Expenses	Col. D - FERC Acct.	Column E - Uncontested 2023 Forecast (\$000s Nominal Dollars)	Column F - Forecast with September 6, 2022 Escalation (\$000s Nominal Dollars)
1	PG&E-07, p. 1A-20, line 13 to p. 1A-21, line 13.	On-Site Clinics	926	\$2,636	\$2,792
2	PG&E-07, p. 1A-5, lines 3-10.	Fit for Duty (FFD)	926	\$83	\$88
3	PG&E-07, p. 1A-22, Table 1A-2	DOT Drug Testing	926	\$876	\$928
4	PG&E-07, p. 1A-22, Table 1A-2	Substance Abuse Intervention	926	\$0	\$0
5	Total Shared Services			\$3,595	\$3,808
6					
7	Human Resources				
8	PG&E-08, p. 5-32, line 29 to p. 5-33, line 6.	Adoption Reimbursement	926	\$17	\$18
9	PG&E-08, p. 5-6, line 14 to p. 5-13, line 21.	Corp: Employee Health Care Contributions	923	\$(12)	\$(11)
10	PG&E-08, p. 5-6, line 14 to p. 5-13, line 21.	Utility: Employee Health Care Contributions	926	\$(41,363)	\$(41,363)
11	PG&E-08, p. 5-32, lines 6-28.	Family Support Program	926	\$33	\$34
12	PG&E-08, p. 5-17, line 18 to p. 5-18, line 2.	Corp: Group Life Insurance Plan	923	\$2	\$2
13	PG&E-08, p. 5-17, line 18 to p. 5-18, line 2.	Utility: Group Life Insurance Plan	926	\$587	\$587
14	PG&E-08, p. 5-19, lines 6-27.	Pension Administration and Compliance - Pay-As-You-Go	926	\$153	\$162
15	PG&E-08, p. 5-18, line 3 to p. 5-29, line 16.	Corp: Post-Retirement Life (Pay-As-You-Go)	923	\$1	\$1
16	PG&E-08, p. 5-18, line 3 to p. 5-29, line 16.	Utility: Post-Retirement Life (Pay-As-You-Go)	926	\$3,292	\$3,488
17	PG&E-08, p. 5-18, line 3 to p. 5-29, line 16.	Post-Retirement Medical (Pay-As-You-Go)	923	\$0	\$0
18	PG&E-08, p. 5-18, line 3 to p. 5-29, line 16.	Post-Retirement Medical (Pay-As-You-Go)	926	\$422	\$447
19	PG&E-08, p. 5-30, line 19 to p. 5-32, line 5.	Service Awards	926	\$893	\$946
20	PG&E-08, p. 5-14, line 26 to p. 5-17, line 17.	Corp: Vision	923	\$1	\$1
21	PG&E-08, p. 5-14, line 26 to p. 5-17, line 17.	Utility: Vision	926	\$3,485	\$3,485
22	PG&E-08, p. 5-27, line 7 to p. 5-29, line 16.	Corp: Trust Contributions – Retiree Medical	923	\$0	\$0
23	PG&E-08, p. 5-27, line 7 to p. 5-29, line 16.	Corp: Trust Contributions – Retiree Medical	926	\$0	\$0
24	PG&E-08, p. 5-27, line 7 to p. 5-29, line 16.	Corp: Trust Contributions – Retiree Life	923	\$2	\$2

Table A4: Companywide Expenses					
Col. A - Line No.	Column B - Cite to Program Information in PG&E's Opening Testimony (Feb. 28, 2022) - Exhibit and Chapter Reference	Column C - Companywide Expenses	Col. D - FERC Acct.	Column E - Uncontested 2023 Forecast (\$000s Nominal Dollars)	Column F - Forecast with September 6, 2022 Escalation (\$000s Nominal Dollars)
25	PG&E-08, p. 5-27, line 7 to p. 5-29, line 16.	Utility: Trust Contributions – Retiree Life	926	\$0	\$0
26	Total Human Resources			\$(32,487)	\$(32,201)
27					
28	Administrative and General¹⁷				
29	PG&E-09, p. 2-19, line 21 to p. 2-20, line 4.	Bank Service Fees	930	\$1,307	\$1,385
30	PG&E-09, p. 2-19, line 21 to p. 2-20, line 4.	Trustee Fees	930	\$20	\$21
31	PG&E-09, p. 2-19, line 21 to p. 2-20, line 4.	Bank Credit Fees	930	\$7,672	\$8,129
32	PG&E-09, p. 3-21, line 22 to p. 3-23, line 23.	General Liability Insurance	925	\$170,581	\$170,723
33	PG&E-09, p. 3-16, line 27 to p. 3-21, line 18.	Property Insurance	924	\$28,645	\$29,003
34	Total Administrative and General			\$208,255	\$209,261
35					
36	Total¹⁸			\$179,333	\$180,868

¹⁷ The list of uncontested items does not reflect the settlement proposal on remaining disputed issues in Appendix G.

¹⁸ Total uncontested companywide expenses represent approximately 9 percent of PG&E's total companywide expense forecast: \$179,333/\$2,054,520 = 9%.

Total forecast is provided in PG&E-064, p. 3-19, Table 3C-1, line 88.

Appendix B

Uncontested Balancing Accounts, Memorandum Accounts and Other Non-Forecast Issues

Appendix B includes five tables listing the uncontested balancing accounts, memorandum accounts, and other forecast issues in this GRC, as well as proposed new accounts:

- Table B-1: Uncontested balancing accounts and memorandum accounts PG&E requests be continued with no modifications;
- Table B-2: Uncontested balancing accounts and memorandum accounts PG&E requests be continued with modifications;
- Table B-3: Uncontested balancing accounts and memorandum accounts PG&E requests be closed at the end of this rate case period (December 31, 2022);
- Table B-4: Other uncontested non-forecast items; and,
- Table B-5: New Gas Operations Accounts.

**Table B-1: Uncontested Balancing Accounts and Memorandum Accounts PG&E
Requests be Continued with no Modifications**

PG&E respectfully requests that the Commission continue the eight uncontested balancing accounts and memorandum accounts in Table B-1 with no modifications. Parties do not dispute PG&E's request related to these accounts.

	Uncontested Balancing and Memorandum Accounts PG&E Proposes Continuing with No Modifications	Location in PG&E's Testimony
	Account	
1	Tax Memorandum Accounts (TMA): Track differences between adopted GRC revenue requirements related to income tax resulting from: (1) net revenue changes, and (2) mandatory or elective tax law, accounting, procedural, or policy changes. Decision Authorizing Account: D.17-05-013	PG&E-10, p. 13-2, line 24 to p. 13-3, line 26.
2	Gas Statutes, Regulations, and Rules Memorandum Account (GSRRMA): Tracks and records incremental costs to comply with any new federal or state statutes, regulations and rules that are issued between GT&S funding cycles. Decision Authorizing Account: D.19-09-025	PG&E-03, p. 6-21, line 22 to p. 6-22, line 14.
3	Officer Compensation Memorandum Accounts (OCMA): Tracks officer compensation authorized in GRC proceedings and amounts paid to officers. Decision Authorizing Account: Resolution (Res.) E-4963 and Public Utilities Code Section 706	PG&E-12, p. 7-4, lines 1-7.
4	Line 407 Memorandum Account (L407MA): Records revenue requirements associated with actual capital expenditures related to the construction of the Line 407 project, above the \$180.8 million adopted amount. Decision Authorizing Account: D.16-06-056	PG&E-16-E, Attach A: p.11-AtchA-2, lines 16-22 and p. 11-AtchA-3, lines 14-18.
5	Balancing Charge Account (BCA): Records revenues and costs associated with providing balancing service. Decision Authorizing Account: D.19-09-025	PG&E-12, p. 7-4, line 8 to p. 7-5, line 4.
6	Major Emergency Balancing Account (MEBA): Tracks the difference between actual and adopted expenses and capital revenue requirements related to responding to major emergencies not eligible for recovery through CEMA. Decision Authorizing Account: D.14-08-032	PG&E-04, p. 6-2, lines 12-16.
7	Rule 20 Balancing Account (RBA): Tracks the difference between actual and adopted revenue requirements to complete overhead to underground conversion projects consistent with the Rule 20A program. Decision Authorizing Account: D.17-05-013; Modified in D.21-06-013	PG&E-04, p. 19-8, lines 21-22.
8	Dimmable Streetlight Implementation Memorandum Account (DSIMA): Tracks and records incremental costs incurred for developing and implementing a dimmable streetlight program in accordance with Phase 2 of PG&E's 2020 GRC. Decision Authorizing Account: D.20-12-005	PG&E-04, p. 7-5, lines 9-19.

Table B-2: Uncontested Balancing Accounts and Memorandum Accounts PG&E Requests be Continued with Modifications

PG&E respectfully requests that the Commission continue the five uncontested balancing accounts and memorandum accounts in Table B-1 with modifications. Parties do not dispute PG&E's request related to these accounts.

	Uncontested Balancing and Memorandum Accounts PG&E Proposes Continuing with Modifications	Location in PG&E's Testimony
	Accounts	
1	Adjustment Mechanism for Costs Determined in Other Proceedings (AMCDOP): Modifications: Remove obsolete subaccounts. Risk transfer amounts allocated to GT&S functions and previously recorded to AMCDOP are proposed to be added to gas RTBA. Decision Authorizing Account: D.19-09-025	PG&E-12, p. 7-11, line 20 to p. 7-12, line 8.
2	Department of Energy Litigation Balancing Account (DOELBA): Records actual proceeds, net of costs, from the DOE related to the DOE's breach of spent fuel contracts and any additional claims for reimbursement related to spent fuel contracts. Modification: PG&E proposes continuing to modify the percentages used to allocate proceeds between the PABA and the Nuclear Decommissioning Adjustment Mechanism (NDAM) based on adopted forecast amounts explicit to Diablo Canyon Power Plant (DCPP) Operations (allocated to PABA) and Humboldt Bay Power Plant and DCPP Decommissioning (allocated to NDAM). Decision Authorizing Account: D.14-08-032	PG&E-05, p. 8-7, line 14 to p. 8-9, line 12.
3	Distributed Energy Resources Distribution Deferral Account (DERDDA): Records and tracks actual costs incurred for: (1) Utility Regulatory Incentive Pilots program and (2) Distributed Resources Plan Distribution Investment Deferral Framework (DIDF) projects. Modification: Since PG&E has included in this GRC a forecast of administrative costs related to the DIDF projects, modify the Distribution Investment Deferral Framework Administrative Cost Memorandum Sub-Account in the DERDDA to only track and record actual administrative costs above the amount adopted by the Commission for future review and approval by the Commission. Decision Authorizing Account: D.16-12-036; D. 18-02-004	PG&E-04, p. 21-33, lines 23-28.
4	Transportation Electrification Balancing Account (TEBA): Tracks the difference between the actual revenue requirements incurred and the forecast revenue requirements for various transportation electrification programs. Modification: PG&E has included in this GRC a forecast for ongoing Operations and Maintenance (O&M) costs associated with some of the programs currently funded outside the GRC through the TEBA. Therefore, PG&E proposes to modify the TEBA to exclude these O&M costs that are now included in the GRC forecast. Decision Authorizing Account: D.18-05-040; D.19-11-017.	PG&E-06-E, p. 2-33, line 14 to p. 2-35, line 26.
5	Core Fixed Cost Account (CFCA) and Noncore Customer Class Charge Account (NCA): Recover adopted gas core and noncore revenue requirements from core and noncore customers. Modification: Updated Natural Gas Storage Strategy (NGSS) proposes to retain Los Medanos (LM) gas storage field and attempt to sell Pleasant Creek (PC). Therefore, remove recording of adopted LM depreciation and decommissioning	PG&E-12, p. 7-2, lines 3-10 and footnote 2.

	Uncontested Balancing and Memorandum Accounts PG&E Proposes Continuing with Modifications	Location in PG&E's Testimony
	costs for recovery in end-use rates. Continue recording these costs for Pleasant Creek. Decision Authorizing Account: D.19-09-025	

Table B-3: Uncontested Balancing Accounts and Memorandum Accounts PG&E Requests be Closed

PG&E requests that the Commission allow PG&E to close the 23¹ uncontested balancing accounts and memorandum accounts in Table B-3. Parties do not dispute PG&E's request related to these accounts.

PG&E is proposing to close 14 accounts for programs in which a reasonable forecast was developed and there are minimal factors beyond PG&E's control that can impact the forecast. As a result, these accounts are no longer necessary. These accounts are identified in the tables below as: Reason for Closing Account – Reasonable Forecast Developed.

PG&E is also proposing to close 9 accounts associated with programs that are ending by 2022 or for programs with a specific purpose that has concluded, which renders these accounts no longer necessary. These accounts are identified in the tables below as: Reason for Closing Account – Account No Longer Necessary.

	Uncontested Balancing and Memorandum Accounts PG&E Proposes Closing	Location in PG&E's Testimony
	Account	
1	Engineering Critical Assessment Balancing Account (ECABA): Tracks the difference between actual and adopted expenses and capital revenue requirements related to the Engineering Critical Assessment Program. The ECA 1 program will end in 2022, and PG&E is able to develop a reasonable forecast of ECA 2 program costs and has included that forecast as part of this GRC, rendering the account no longer necessary. Decision Authorizing Account: D.19-09-025 Reason for Closing Account: Reasonable Forecast Developed	PG&E-03, p. 6-78, line 14 to p. 6-79, line 28.
2	Shareholder-Funded Gas Transmission Safety Account (SFGTSA): As described in Exhibit (PG&E-3), Chapter 5, PG&E proposes to record its remaining obligation of approximately \$30 million towards the Inoperable and Hard-to-Operate Valves program, an approved safety capital program in which PG&E has invested above the authorized amount. With this, PG&E has satisfied its required safety-spend capital penalty. Once all the CPUC requirements associated with the account are completed PG&E will file an advice letter to close the SFGTSA. Specifically, an independent auditor will prepare an audit of PG&E's final accounting of amounts recorded in the account and serve its final audit report on all parties who PG&E served with its annual accounting. Thereafter, PG&E shall file an advice letter to close out the account. Decision Authorizing Account: D.15-04-024	PG&E-12, p. 6-15, Table 6-2, line 2.

¹ There are 22 lines in the table below. Line 20, the California Consumer Privacy Act Memorandum Accounts, includes two accounts, one for Gas and one for Electric, bringing the total number of accounts in Table B-3 to 23.

	Uncontested Balancing and Memorandum Accounts PG&E Proposes Closing	Location in PG&E's Testimony
	Reason for Closing Account: Account no Longer Necessary	
3	Critical Documents Program Memorandum Account (CDPMA): Tracks actual expenses related to updating existing station documents or creating new documentation for facilities built on or before December 31, 1955. The program is expected to end in 2022, rendering this account no longer necessary. Decision Authorizing Account: D.16-06-056 Reason for Closing Account: Account no Longer Necessary	PG&E-03, p. 6-117, lines 18 and 24.
4	Dairy Biomethane Solicitation Memorandum Account (DBSMA): Records expenditures for solicitation development. Account related to a one-time event that has concluded. The DBSMA was established outside of a GRC proceeding but is included herein because PG&E is providing a reasonableness showing in Track 2 of the 2023 GRC. Decision Authorizing Account: D.17-12-004 Reason for Closing Account: Account no Longer Necessary	PG&E-03, p. 14-32, line 4 to p. 14-33, line 12.
5	Below-Ground Storage Decommissioning Balancing Account (BGSDBA): Records differences between the adopted and actual expenses of below-ground storage well decommissioning activities for Los Medanos and Pleasant Creek storage fields. PG&E proposes to retain Los Medanos, so a decommissioning balancing account is not needed for this facility. If PG&E sells Pleasant Creek, PG&E will file a section 851 application that will address decommissioning. If PG&E does not sell Pleasant Creek, decommissioning will be processed as usual through depreciation expense. For all these reasons, the BGSDBA is unnecessary. Decision Authorizing Account: D.19-09-025 Reason for Closing Account: Account no Longer Necessary	PG&E-03, p. 7-63, line 13 to p. 7-64, line 7.
6	Cushion Gas Memorandum Account (CGMA): Tracks the gain on sale of cushion gas from the Los Medanos and Pleasant Creek storage fields. If PG&E's proposal to retain Los Medanos is approved, cushion gas will not be sold. For Pleasant Creek, PG&E has no plans to produce cushion gas for sale. For these reasons, the account is no longer necessary. Decision Authorizing Account: D.19-09-025 Reason for Closing Account: Account no Longer Necessary	PG&E-03, p. 7-64, lines 9-23.
7	Measurement and Control Station Rebuilds Balancing Account (MCSRBA): Tracks the difference between the revenue requirement based on adopted capital expenditures for the Measurement and Control station rebuilds program and the revenue requirement associated with actual capital expenditures. PG&E can develop a reasonable forecast since there is limited risk of project delays related to permit delays, rendering the account unnecessary. Decision Authorizing Account: D.19-09-025 Reason for Closing Account: Reasonable Forecast Developed	PG&E-03, p. 6-46, lines 5-26.
8	Hydrostatic Testing Balancing Account (HTBA): Records the difference between the adopted and actual expenses of the Hydrostatic Testing Program. PG&E has significantly improved its strength test cost calculator and thus is able to develop a reasonable forecast of the program, which is included as part of this GRC, rendering the account unnecessary. Decision Authorizing Account: D.19-09-025 Reason for Closing Account: Reasonable Forecast Developed	PG&E-03, p. 5-71, lines 2-21.

	Uncontested Balancing and Memorandum Accounts PG&E Proposes Closing	Location in PG&E's Testimony
9	Atmospheric Corrosion Balancing Account (ACBA): Records the difference between the adopted and actual expenses of the Atmospheric Corrosion Program. This account was created to address historic underspend in the Atmospheric Corrosion program and an overestimation of prior forecasts. PG&E can develop a reasonable forecast of the program going forward as part of this GRC, rendering the account unnecessary. Decision Authorizing Account: D.19-09-025 Reason for Closing Account: Reasonable Forecast Developed	PG&E-03, p. 9-46, lines 2-11.
10	Physical Security Balancing Account (PSBA): Tracks the difference between the revenue requirement based on adopted capital expenditures for the Physical Security Program and the revenue requirement associated with actual capital expenditures. As a result, PG&E can develop a reasonable forecast of Physical Security program costs and has included that forecast as part of this GRC, rendering the balancing account unnecessary. Decision Authorizing Account: D.19-09-025 Reason for Closing Account: Reasonable Forecast Developed	PG&E-03, p. 6-86, lines 9-30.
11	Measurement and Control Over-Pressure Protection Memorandum Account (MCOPMA): Tracks the revenue requirement associated with capital expenditures for the Measurement and Control Station Over-Pressure Protection Program. PG&E can reasonably forecast ongoing amounts and has included that forecast in this GRC, rendering the account unnecessary. Decision Authorizing Account: D.19-09-025 Reason for Closing Account: Reasonable Forecast Developed	PG&E-03, p. 6-69, line 15 to p. 6-70, line 32.
12	Root Cause Analysis Memorandum Account (RCAMA): Tracks actual expenses related to the Root Cause Analysis Program above the aggregate amount adopted in PG&E's 2019 GT&S rate case (\$11.148 million). PG&E can reasonably forecast the work previously recorded in the RCAMA and has included that forecast in this GRC, rendering the account unnecessary. Decision Authorizing Account: D.19-09-025 Reason for Closing Account: Reasonable Forecast Developed	PG&E-03, p. 5-96, line 18 to p. 5-97, line 4.
13	Alternating Current Interference Balancing Account (ACIBA): Records the difference between capital revenue requirements adopted for the Alternating Current Interference program and revenue requirements associated with actual capital expenditures. PG&E can develop a reasonable forecast of the program, which is included as part of this GRC, rendering the account unnecessary. Decision Authorizing Account: D.19-09-025 Reason for Closing Account: Reasonable Forecast Developed	PG&E-03, p. 9-56, line 12 to p. 9-57, line 2.
14	Routine Compression and Processing Memorandum Account (RCPMA): Tracks actual expense incurred for the Routine Compression and Processing (C&P) program above the amount adopted in the 2019 GT&S rate case. PG&E has provided a forecast for C&P expenses in this GRC case. Any costs related to new regulations and statutes could be tracked in PG&E's GSRRMA. Therefore, the RCPMA is not necessary. Decision Authorizing Account: D.19-09-025 Reason for Closing Account: Reasonable Forecast Developed	PG&E-03, p. 6-21, line 6 to p. 6-22, line 14.
15	Casings Balancing Account (CBA): Tracks the difference between the revenue requirement based on adopted capital expenditures for the Casings Program and the revenue requirement associated with actual capital expenditures. PG&E can develop a reasonable forecast of the program, which is included as part of this GRC, rendering the account unnecessary. Decision Authorizing Account: D.19-09-025	PG&E-03, p. 9-50, lines 4-11.

	Uncontested Balancing and Memorandum Accounts PG&E Proposes Closing	Location in PG&E's Testimony
	Reason for Closing Account: Reasonable Forecast Developed	
16	Locate and Mark Memorandum Account (LMMA): Tracks expenses incurred for the Locate and Mark program that exceed the aggregated total amount adopted in PG&E's 2019 GT&S rate case. PG&E can develop a reasonable forecast of the program. PG&E has not needed to utilize this account and recommends it be closed. Decision Authorizing Account: D.19-09-025 Reason for Closing Account: Reasonable Forecast Developed	PG&E-03, p. 8-47, line 26 to p. 8-48, line 9.
17	Rate Base Adjustments Memorandum Account (RBAMA): Tracks the difference in the total revenue requirement resulting from the difference between the adopted year-end 2018 rate base balance (which includes PG&E's forecasted rate base additions) and the rate base based on actual capital expenditures for 2018. This account was mandated by the CPUC for a specific year. The period is over, and the account is no longer needed. Decision Authorizing Account: D.19-09-025 Reason for Closing Account: Account no Longer Necessary	PG&E-12, p. 7-25, Table 7-4, line 21.
18	Nuclear Regulatory Commission Rulemaking Balancing Account (NRCRBA): Tracks the difference between actual and adopted expenses for complying with Nuclear Regulatory Commission regulations and rulemakings. At the end of DCP's operations, PG&E will no longer have operating nuclear facilities and thus will not need this account. At the end of operations, PG&E will file a future Tier 1 AL to transfer the final balance in the NRCRBA to PABA and close the account. Decision Authorizing Account: D.14-08-032 Reason for Closing Account: Account no Longer Necessary	PG&E-18, p. 8-2, lines 9-11. PG&E-05, p. 3-2, lines 3-23.
19	Diablo Canyon Retirement Balancing Account (DCRBA): PG&E plans to utilize the DCRBA through each unit of DCP's operational license termination dates in 2024 and 2025. Once the balance in the account has been recovered, PG&E will file a Tier 1 AL to close the account. Decision Authorizing Account: D.18-01-022 Reason for Closing Account: Account no Longer Necessary	PG&E-05, p. 8-5, line 20 to p. 8-6, line 17.
20	California Consumer Privacy Act Memorandum Accounts- Electric and Gas (CCPAMAs): PG&E requests approval to close these accounts effective December 31, 2022. Forecasts supporting these activities have been included in PG&E's 2023 GRC request. Decision Authorizing Account: D.19-09-026 Reason for Closing Account: Reasonable Forecast Developed	PG&E-06-E, p. 8-15, line 4 to p. 8-16, line 2.
21	California Distributed Generation Statistics Website Memorandum Account (CDGSWMA): Tracks and records incremental costs for work performed by the Distributed Generation Statistics contractor for the 3-year period of January 1, 2020, to December 31, 2022. The period governed by this account will end in 2022, rendering its future use unnecessary. Decision Authorizing Account: Resolution (Res.) E-5030 Reason for Closing Account: Account no Longer Necessary	PG&E-06-E, p. 2-32, line 23 to p. 2-33, line. .
22	Residential Rate Reform Memorandum Account (RRRMA): Beginning in 2023, PG&E proposes to recover the forecasted costs for rate reform activities through GRC revenues to allow for the completion of Default TOU Transition and required ongoing annual Residential Rate Comparison communications. As a result, the account is no longer necessary. Decision Authorizing Account: D.15-07-001	PG&E-06-E, p. 3-27, line 11 to p. 3-28, line 3.

	Uncontested Balancing and Memorandum Accounts PG&E Proposes Closing	Location in PG&E's Testimony
	Reason for Closing Account: Reasonable Forecast Developed	

Table B-4: Other Uncontested Non-Forecast Items

PG&E requests that the Commission authorize the 20 uncontested non-forecast items in

Table B-4. Parties do not dispute PG&E's request related to these accounts.

	Other Uncontested Non-Forecast Items	Location in PG&E's Testimony
	Item	
1	Inventory Management - Approve PG&E's proposal not to change Inventory Management.	PG&E-03, p. 7-54, lines 14-29.
2	Convert Working Gas to Cushion Gas at Los Medanos - If PG&E's proposal to retain the Los Medanos facility is approved, approve PG&E's proposal to convert the non-cycle working gas to cushion gas.	PG&E-03, p. 7-61, lines 2-12.
3	Core Gas Supply Firm Storage - Approve PG&E's proposal to increase the Core Gas Supply Firm Storage from 307 million cubic feet per day (MMcf/d) to 411 MMcf/d for the four gas storage years starting April 1, 2023 through March 31, 2027.	PG&E-03, p. 7-55, lines 2-14.
4	Payroll and Other Taxes - Approve PG&E's calculation method and the resulting 2023 forecast for distribution-related payroll and other taxes. Approve PG&E's calculation method and the resulting 2023 forecast for generation-related payroll and other taxes. Approve PG&E's calculation method and the resulting 2023 forecast for GT&S-related payroll and other taxes.	PG&E-10, p. 9-1, lines 16-30.
5	Electric, Gas and Other Plant - Approve PG&E's proposal to amortize implementation costs for a cloud computing arrangement that is a service contract consistent with other capitalized software projects.	PG&E-10, p. 10-16, lines 12-31.
6	Electric, Gas, and Common Plant - Approve PG&E's proposal to capitalize and amortize upfront prepaid license and maintenance agreements on the purchase of new hardware or software for regulatory recovery.	PG&E-10, p. 10-17, lines 1-9.
7	Electric, Gas, and Common Plant - Approve PG&E's proposal to capitalize upfront payments and implementation costs related to lease fiber-optic circuits under a long-term indefeasible right of use agreement.	PG&E-10, p. 10-16, lines 10-23.
8	Electric, Gas, and Common Plant - Approve PG&E's proposal to capitalize the first time and one-time pipeline testing costs incurred to comply with new Pipeline and Hazardous Materials Safety Administration federal safety standards.	PG&E-10, p. 10-16, line 26 to p. 10-17, line 3.
9	Other Operating Revenues (OORs) - Adopt PG&E's 2023 forecast of electric and gas distribution OORs of \$188.6 million and \$33.6 million respectively, and the forecast of electric generation and gas transmission and storage of \$13.5 million and \$11.0 million, respectively	PG&E-10, p. 16-1, lines 26-33.
10	Administrative and General Expense Allocation Factors - Adopt: PG&E's methodology used to allocate total Company A&G expense to capital, Below-the Line and non-utility affiliates; the unbundling and allocation of utility common A&G expenses to electric distribution, gas distribution, electric generation, gas transmission and storage functional areas for use in the GRC and in other, non-GRC, Commission ratemaking mechanisms; and other high-level adjustments.	PG&E-10, p. 8-1, line 15 to p. 8-2, line 5.
11	Department of Energy Litigation Refund - PG&E's proposed change to the allocation methodology for the amounts received from the Department of Energy reimbursing PG&E for the costs to store DCPD spent fuel.	PG&E-18, p. 8-2, lines 12-15. PG&E-05, p. 3-49, line 21 to p. 3-51, line 13.

	Other Uncontested Non-Forecast Items	Location in PG&E's Testimony
12	DCPP materials surplus inventory -PG&E's updated calculation of the end-of-life inventory balance, proposed changes in the treatment of the salvage activity, and an increase in the amortization period for the materials surplus inventory.	PG&E-05, p. 3-2, line 26 to p. 3-3, line 10. PG&E-18, p. 8-2, lines 16-17.
13	DCPP materials surplus inventory - PG&E's proposal to charge any procurement department labor incurred after August 2025 incurred for purposes of inventory salvage and disposal to the Diablo Canyon Retirement Balancing Account	PG&E-05, p. 3-3, lines 10-12.
14	DCPP project cancellation costs - The update to the project cancellation amounts is consistent with the DCPP retirement decision.	PG&E-05, p. 8-5, lines 2-19.
15	DCPP net book value - Continue to recover the net book value associated with Diablo Canyon Power Plant (DCPP) through the Diablo Canyon Retirement Balancing Account (DCRBA) and close the DCRBA at the end of plant life.	PG&E-18, p. 8-2, lines 6-8. PG&E-05, p. 8-5, line 20 to p.8-6, line 17.
16	Hydro Decommissioning - The continuation of a decommissioning accrual for hydroelectric facilities.	PG&E-18, p. 8-2, lines 21-24.
17	Calculate and Implement Electric Rates - PG&E requests approval to calculate and implement electric rates that incorporate the revenue requirements authorized by this proceeding. Electric rates will be calculated based on the adopted electric sales and billings forecast and approved revenue allocation and rate design methodologies in effect at the time of implementation. PG&E requests that rates implemented by this decision be consolidated with rate changes implemented as soon as practicable once a final decision is issued.	PG&E-12, p. 4-2, lines 7-13 and PG&E-12, Chapter 4, Errata Index, p. ii, referencing p. 4-2, lines 11-13.
18	Calculate and Implement Gas Rates - PG&E proposes to implement the GT&S revenue requirements and capacity forecasts adopted in the GRC Phase I proceeding concurrent with the throughput forecast, backbone load factor, and CARD methodologies adopted in PG&E's 2023 GT&S CARD proceeding. PG&E filed its CARD application (A.21-09-018) on September 30, 2021 in order to facilitate the proposed implementation. PG&E requests approval, upon approval of the 2023 GRC, to calculate and implement end-user gas rates for the authorized 2023 gas distribution, backbone transmission, local transmission, customer access charge, and storage revenue requirements. Within 60 days of a decision in both PG&E's 2023 GRC and its PG&E's 2023 GT&S CARD, PG&E will submit a Tier 2 advice letter (AL) to update the allocations of non-GT&S rate elements, including distribution rates, for the newly adopted throughput and billings forecasts. Upon approval of that Tier 2 AL, PG&E will implement the updated end-user rates as soon as practicable. The rate changes to recover the change to Public Purpose Program Surcharge CARE Discounts will be implemented as part of the following October 31 annual filing of PG&E's Gas Public Purpose Program Surcharge (G-PPPS) Tier 2 ALs. Those changes will go into effect the following January 1.	PG&E-12, p. 5-2, line 17 to p. 5-3, line 19.
19	Consolidated approach for adopted trust contributions - As agreed in the 2007 GRC D.07-03-044, PG&E uses a consolidated approach for adopted contribution amounts for the PBOPs and LTD. For example, if the amount adopted for the contribution to the Post-Retirement Medical Plan Trust could not be contributed to the plan's trust on a tax-deductible basis, the amount could be contributed to the LTD Trust (up to the maximum tax-deductible amount). Funds collected in rates that cannot be contributed to the trusts on a tax-deductible basis must be returned to customers through a true-up filing at the end of each rate case cycle.	PG&E-08, p. 5-27, line 21 to p. 5-28, line 2.

	Other Uncontested Non-Forecast Items	Location in PG&E's Testimony
20	Discontinue Shareholder Account Annual Reporting (D. 15-04-024, San Bruno Explosion and Fire OII) – PG&E proposes to record its remaining obligation of approximately \$30 million to the Shareholder-Funded Gas Transmission Safety Account (SFGTSA) to satisfy the requirements set forth in D.14-04-024. PG&E will work with an independent auditor to confirm it has satisfied all the requirements and will file an advice letter to close this account. Once the account is closed, PG&E requests approval to discontinue the SFGTSA annual reporting requirement.	PG&E-12, p. 6-15, Table 6-2, line 2.

Table B-5: New Gas Operations Accounts

PG&E identifies two new accounts that should be established in connection with PG&E's Gas Distribution Capital New Business Program (tracked in MWC 29).

	New Balancing and Memorandum Accounts PG&E Proposes Establishing	Location in PG&E's Brief
	Account	
1	Gas Allowance 1-Way Balancing Account: CPUC Decision 22-09-026 issued September 15, 2022 eliminated the gas line extension allowances as of July 1, 2023. In light of this decision PG&E proposes a revised forecast for MWC 29 that should be subject to a one way balancing account. The Gas Allowance Decision “adopts Energy Division’s staff proposal to eliminate gas line extension allowances . . . under the current gas line extension rules. The elimination is for all customers in all customer classes effective July 1, 2023. . . . Applications submitted before July 1, 2023 will not be affected by this decision.” In light of this decision, PG&E’s forecasts for MWC 29 should be reduced since PG&E’s original forecast assumed that gas line extension allowances would continue to be in effect for the entire GRC forecast period. However, despite the elimination of allowances for applications received after July 1, 2023, a significant portion of the forecast will still be needed for: (1) ongoing allowances and refunds related to currently eligible projects that are already completed or will be completed in the future; (2) allowances and future refunds for projects constructed under new applications submitted to PG&E before July 1, 2023; and (3) other miscellaneous costs required for new gas connections, including costs that are not covered by the applicant, i.e., estimate vs. actual cost variations due to timing, and certain meter material costs. PG&E requests a revised 2023 forecast for MWC 29 of \$85.4 million, i.e., \$20 million for on-going non-allowance related costs, and \$65.4 million for allowances on in-flight projects and new project applications. To protect ratepayers against the uncertainty of this forecast, PG&E also proposes that the revenues associated with this forecast be trued up at the end of the rate case cycle by means of a one-way balancing account. Decision Authorizing Account: D.22-09-026	Section 3.13.2.1
2	Gas Allowance Memorandum Account: CPUC Decision 22-09-026 issued September 15, 2022 eliminated the gas line extension allowances as of July 1, 2023. PG&E requests clarification regarding funding for specific unique non-residential projects approved pursuant to the post-July 2023 special application process approved in D. 22-09-026, and proposes a memorandum account to track costs associated with these projects. D.22-09-026 “approves the Joint Parties and TURN’s proposal for an application process, with modifications, for those specific, unique non-residential projects where a gas line subsidy may still be warranted. For these projects, the gas IOUs shall evaluate the project based on the criteria established in this decision and file an application with the Commission for approval of a gas line subsidy on behalf of the project applicant(s).” PG&E requests that the Commission clarify the cost recovery process for projects that may be approved pursuant to the annual July 1 application process. The Commission should either confirm that cost recovery will be authorized and addressed in the applications, or the Commission should authorize PG&E to	Section 3.13.2.2

	New Balancing and Memorandum Accounts PG&E Proposes Establishing	Location in PG&E's Brief
	establish a memorandum account to recover the allowance/subsidy costs for approved projects Decision Authorizing Account: D.22-09-026	

Appendix C

Contested Balancing Accounts and Memorandum Accounts

Appendix C includes four tables that lists the contested Balancing Accounts and Memorandum Accounts. The table provides a brief description of the account, a summary of PG&E's position, a reference to where the issue is discussed in PG&E's opening testimony and/or rebuttal testimony, and a reference to where the account is discussed in the Opening Brief.

- Table C-1: Contested Balancing Accounts and Memorandum Accounts PG&E Requests be Continued with No Modifications;
- Table C-2: Contested Balancing Accounts and Memorandum Accounts PG&E Requests be Continued with Modifications;
- Table C-3: PG&E's Proposed New Balancing Accounts and Memorandum Accounts - Contested; and
- Table C-4: Balancing Accounts and Memorandum Accounts that PG&E Proposes Closing – Contested.

Table C-1 Summary of Contested Balancing and Memorandum Accounts that PG&E Proposes Continuing with No Modifications			
	Account	Summary of PG&E's Proposal	Location where Account is Discussed in PG&E's Opening Testimony, Rebuttal Testimony and Brief
1	New Environmental Regulations Balancing Account (NERBA): Tracks actual expenses and capital revenue requirements compared to the adopted budget for incremental best practice activities related to Grade 3 leak repairs. Decision Authorizing Account: D.20-12-005	Under Best Practice (BP) 21 adopted in the Leak Abatement OIR, all leaks must be repaired within three years of discovery, except for leaks that are costly to repair relative to their size. The OIR also authorized PG&E to track the costs of BP compliance in a balancing account. Subsequently, PG&E filed Advice Letters establishing the NERBA, and estimating the costs of BP compliance, including for Below Ground Grade 3 (BG3) leak repair. In the 2020 GRC, PG&E requested the NERBA be continued to only track BG3 leaks given the ongoing uncertainty surrounding what amount of BG3 leak repair was cost effective for the utility to perform. Uncertainty around the number of BG3 repairs is likely to continue as additional cost effectiveness data is reported in each biennial leak abatement compliance plan, and the SPD has the opportunity to revisit the BG3 repair rate. There are three biennial leak abatement compliance plans that will be approved or submitted before 2026 (2022-2023; 2024-2025; and 2026-2027). Based on any one of these plans, staff could decide that in light of changing cost effectiveness of BG3 repairs, or the relative cost effectiveness of BG3 repairs compared to other Best Practice methane mitigation measures, that a different level of BG3 repairs is appropriate in a future year. Continuing NERBA as PG&E proposes is necessary given the potential for BG3 leak repairs to fluctuate as new cost effectiveness data becomes available. Accordingly, PG&E requests continuation of NERBA to record BG3 leak repairs.	Opening Testimony: PG&E-03, p. 10-49, line 2 to p. 10-52, line 20. Rebuttal: PG&E-16-E, p. 10-23, line 18 to p. 10-28, line 23. Brief: Section 3.9.5

Table C-2 Summary of Contested Balancing and Memorandum Accounts that PG&E Proposes Continuing with Modifications			
	Account	Summary of PG&E's Proposal	Location where Account is Discussed in PG&E's Opening Testimony, Rebuttal Testimony and Brief
1	Transmission Integrity Management Program Balancing Account (TIMPBA): A one-way balancing account that tracks actual costs up to adopted TIMP amount. Modification: Allow two-way balancing account treatment for costs up to 135 percent of adopted amounts, including costs associated with new TIMP regulations. PG&E would seek to annually true up costs incurred above the adopted amount up to 135 percent of the total adopted amount through a Tier 2 AL. Review and approval of actual costs above 135 percent of adopted through an application. Alternatively, if the TIMPBA remains a one-way balancing account, the TIMPMA should be modified to track costs above adopted amounts related to existing TIMP regulations given the mandatory compliance nature of the costs and uncertainty related to additional changes in regulation. Decision Authorizing Account: D.19-09-025	PG&E currently has a one-way balancing account for TIMP related costs that occur during the 2019 GT&S Rate Case period (i.e., 2019-2022). The TIMPBA was approved by the Commission in the 2019 GT&S Rate Case decision. PG&E also has a memorandum account referred to as the TIMPMA. The TIMPMA was first established by the Commission in the 2015 GT&S Rate Case decision (D.16-06-056) and is used to record any costs "associated with any new transmission integrity management statutes or rules, or new or changed interpretation by a regulatory body of transmission or integrity management statutes or rules." PG&E proposes that the TIMPBA be converted to a two-way balancing account and that the TIMPMA be eliminated. Converting the TIMPBA into a two-way balancing account and eliminating the TIMPMA is consistent with recent Commission decisions and would reduce the administrative complexity facing stakeholders and the Commission. If the Commission does not adopt PG&E's proposal, as an alternative, PG&E is proposing that the TIMPBA remain a one-way balancing account and the TIMPMA be modified to track costs above adopted amounts related to existing TIMP regulations	Opening Testimony: PG&E-03, p. 5-15, line 7 to p. 5-20, line 2. Rebuttal: PG&E-16-E, p. 5-78, line 26 to p. 5-83, line 7. Brief: Section 3.4.7
2	Wildfire Mitigation Balancing Accounts (WMBA): The WMBA tracks and records actual expenses and capital revenue requirements compared to the total adopted amounts for fire risk mitigation work. PG&E is required to file an application to request recovery if any actual amounts that exceed 115 percent of adopted amounts ("reasonableness threshold"). Modification: Increase the threshold for reasonableness review to 125 percent of adopted costs. This change is consistent with PG&E's proposed changes to increase the reasonableness review threshold in the VMBA from	PG&E records wildfire mitigation related activities in the two-way WMBA. This includes those activities described in this application, as well as activities in PG&E's WMP. PG&E recommends that the WMBA reasonableness review threshold for total spending and recorded average per mile for the various types of unit costs be raised from 115 percent to 125 percent. There is uncertainty regarding the wildfire mitigation costs PG&E ultimately will incur versus what is forecast in this GRC. Due to this uncertainty, a two-way balancing account is an appropriate ratemaking mechanism because: (1) a one-way balancing account	Opening Testimony: PG&E-04, p. 4-22, line 20 to p. 4-24, line 27. Rebuttal Testimony: PG&E-17, p. 4-2, line 16 to p. 4-8, line 13. Brief: Section 4.24.1

Table C-2 Summary of Contested Balancing and Memorandum Accounts that PG&E Proposes Continuing with Modifications			
	Account	Summary of PG&E's Proposal	Location where Account is Discussed in PG&E's Opening Testimony, Rebuttal Testimony and Brief
	120 percent to 125 percent of adopted amounts. Decision Authorizing Account: D.20-12-005	effectively imposes a cap on spending that restricts PG&E's ability to reasonably adjust its plans as necessary to respond appropriately to wildfire risks, including adjusting the mix of overhead system hardening and undergrounding; (2) it gives PG&E the flexibility to evaluate and introduce new risk mitigation strategies into PG&E's wildfire mitigation portfolio; (3) the weather and the length of the wildfire season are unpredictable and it is difficult to forecast the location, number, size, and duration of PSPS events; and (4) PG&E is assessing how it can continue to refine the incorporation of asset health and the presence of known, high-risk vegetation conditions adjacent to powerlines into PSPS decision-making leading to uncertainty in forecasting the number of PSPS events. Increasing the threshold to 125 percent will allow investments in cost-effective mitigations based on the most current information and analyses. PG&E also needs to be able to quickly respond to new legislative and regulatory directives	
3	Vegetation Management Balancing Account (VMBA): In D.20-12-005, the Commission modified the VMBA to become a two-way balancing account. D.20-12-005 also required that tree mortality costs, which previously had been recorded in CEMA, be recorded in the VMBA. Because there was no approved forecast amount for these costs in the 2020 GRC proceeding, PG&E recorded these costs directly into the Reasonableness Review subaccount of the VMBA. PG&E has included a forecast of these tree mortality costs in this 2023 GRC proceeding Modification: Include tree mortality costs in the Main Subaccount and increase the threshold for reasonableness review to 125 percent of adopted amounts. This proposed change is consistent with PG&E's proposal to	The two-way VMBA continues to be appropriate for VM programs as it addresses potential changes to current program scope related to on-going and unforeseen regulatory, external commitments, customer input, weather, and other environmental/climate impacts that can adversely impact forecasts. Uncertainties and risks to the forecast include: • California continues to suffer through drought conditions which can have significant impacts on VM work. The state has issued 2021 drought declarations and the duration and extent of drought conditions is uncertain; • Addressing dead, dying and sick trees as required in the Tree Mortality Program is driven by climate conditions, making it difficult to	Opening Testimony: PG&E-04, p. 9-44, line 10 to p. 9-48, line 21. Rebuttal: PG&E-17, p. 9-11, line 10 to p. 9-15, line 31. Brief: Section 4.24.2

Table C-2 Summary of Contested Balancing and Memorandum Accounts that PG&E Proposes Continuing with Modifications			
	Account	Summary of PG&E's Proposal	Location where Account is Discussed in PG&E's Opening Testimony, Rebuttal Testimony and Brief
	increase the WMBA reasonableness review threshold to 125 percent of the adopted forecast. Decision Authorizing Account: Modified in D.20-12-005	accurately forecast the amount of work required each year; - The scope of the Wood Management Program is uncertain and is impacted by the scope of work and/or availability of facilities to process woody debris which can have a material impact on cost forecasts; and - PG&E is committed to completing the highest risk VM work as determined by the VM Wildfire Risk Model Outputs from the model will impact tree trim and removal rates that can result in material changes to cost forecasts.	
4	Z-Factor Memorandum Accounts (ZFMA): Tracks costs associated with events that are potential Z-factors, which are exogenous and unforeseen events largely beyond PG&E's control that have a material impact on PG&E's costs. In the 2020 GRC, the Commission approved PG&E's request to modify the ZFMAs to include test-year events, as well as PTY events. Modification: Change process to request recovery of any recorded balances through an advice letter instead of an application consistent with the Commission's approved process for Southern California Edison (SCE). Decision Authorizing Account: D.12-20-005	PG&E's current Z-Factor, as adopted in PG&E's 2020 GRC settlement, authorizes tracking of costs for the TY and PTY. PG&E proposes to continue the Z-factor mechanism with a modification to update test year and post-test year and PTY revenue requirement adjustments through an advice letter (AL) process.	Opening Testimony: PG&E-11, p. 2-4, line 20 to p. 2-5, line 2. Rebuttal: PG&E-24-E, p. 1-27, lines 3-13. Brief: Section 12.3.2
5	Hydro Licensing Balancing Account (HLBA): Tracks and adjusts for the difference between actual and adopted expenses, and capital revenue requirements associated with hydro relicensing activities, which include, but are not limited to, renewing, amending, surrendering, decommissioning, compliance requirements, FERC and California DSOD regulatory fees, costs associated with implementation of the Crane Valley Recreation Settlement Agreement, and costs associated with work required as a result of the 2017	The purpose of the Hydro License Balancing Account (HLBA) is to recover actual expenses and capital revenue requirements based on actual capital expenditures related to FERC hydro licensing activities, which include, but are not limited to, renewing, amending, surrendering, decommissioning, compliance requirements, FERC and California DSOD regulatory fees, costs associated with implementation of the Crane Valley Recreation Settlement Agreement, and costs associated with work required as a result of the 2017	Opening Testimony: PG&E-05, p. 4-72, lines 1-15 and PG&E-05, p. 8-10, line 1 to p. 8-11, line 33. Rebuttal: PG&E-18, p. 8-7, line 1 to p. 8-12, line 29. Brief: Section 5.8.2.

Table C-2			
Summary of Contested Balancing and Memorandum Accounts that PG&E Proposes Continuing with Modifications			
	Account	Summary of PG&E's Proposal	Location where Account is Discussed in PG&E's Opening Testimony, Rebuttal Testimony and Brief
	Oroville Dam incident. Modification: Include pre-2012 settlement agreements in the HLBA. The timing and magnitude of activities are determined solely by Forest Service staff, and thus beyond PG&E's control. The 2012 threshold date that was established in the 2014 GRC is an arbitrary date for out of license settlement agreements since PG&E has very little control over the timing of the implementation of activities required by these settlement agreements. Decision Authorizing Account: D.14-08-032; D.20-12-005	Oroville Dam incident. Does not reflect the agreement reached between PG&E and TURN reflecting a complete resolution of disputed Energy Supply issues between PG&E and TURN included in Appendix E.	
6	Risk Transfer Balancing Accounts (RTBA): The RTBAs are comprised of three types of subaccounts. The Third-Party Subaccounts are two-way balancing accounts that track the GRC portion of the difference between adopted and actual expenses related to general liability insurance coverage up to \$1.4 billion, which includes both non-wildfire and wildfire insurance. Costs associated with purchasing insurance above \$1.4 billion in liability coverage are recorded and tracked in the Additional Coverage Subaccount for future review and approval by the Commission. Finally, any adopted funding recorded in the Third-Party Subaccounts not used to purchase insurance, are transferred to the Self-Insurance Subaccount to fund self-insurance expenses up to \$1 billion. Modifications: Separate coverage caps for wildfire (\$1.0 billion) and non-wildfire (\$700 million) liability coverage. PG&E proposes to obtain \$1.0 billion of wildfire liability coverage through a combination of insurance from third-parties and self-insurance. The Self-Insurance Coverage Subaccount tracks available self-insurance coverage. Purchases of self-insurance will continue to	In the 2020 GRC, the Commission authorized creation of the two-way RTBA to manage the uncertain costs associated with General Liability insurance that were not easily forecast. In doing so, the Commission stated: Regarding the establishment of the RTBA, we agree that insurance costs for General Liability coverage has been difficult to predict in recent times because of market conditions and the recent wildfires in California. A two-way balancing account will also allow PG&E to address uncertainty in a timely manner and at the same time ensure that there is adequate insurance coverage The current RTBA terms are as follows: PG&E shall establish a two-way RTBA to recover the costs of PG&E's excess liability insurance coverage exceeding its adopted forecast for coverage of up to \$1.4 billion. PG&E may file a Tier 2 advice letter for coverage beyond \$1.4 billion. PG&E requested authority to continue the RTBA with modifications for the 2023 GRC period for its wildfire and non-wildfire liability programs, to manage the proposed insurance attrition adjustment, and for excise taxes. On October 7, 2022, PG&E, TURN and Cal Advocates, filed a motion for	Rebuttal: PG&E-22, p. 3-14, line 3 to p. 3-47, line 16. Brief: Section 9.4.2.2.1

Table C-2 Summary of Contested Balancing and Memorandum Accounts that PG&E Proposes Continuing with Modifications			
	Account	Summary of PG&E's Proposal	Location where Account is Discussed in PG&E's Opening Testimony, Rebuttal Testimony and Brief
	accumulate in this subaccount until the balance of available self-insurance coverage reaches \$1 billion, at which point PG&E will file a tier 2 advice letter requesting to reduce or eliminate the adopted self-insurance and/or third-party insurance funding. PG&E will include in the advice letter a proposal to return any unspent funding in this subaccount that results once purchases of \$1 billion of self-insurance coverage is reached. Self-insurance will be funded exclusively through CPUC-jurisdictional, retail rates for the 2023 GRC period. PG&E will pursue recovery of self-insurance costs from wholesale customers through the FERC process over the course of the 2023 GRC period. To the extent PG&E is successful, the costs recovered will be credited back to retail customers through the RTBA. Decision Authorizing Account: D.20-12-005	adoption of settlement that would resolve all issues with respect to PG&E's wildfire liability insurance program and forecast. The settlement provides for a 100% self-insurance framework for wildfire liability insurance. Among other things, the settlement provides: (1) an initial \$400 million revenue requirement for 2023 (2) that none of the self-insurance funding shall be subject to additional reasonableness review or refund; (3) a shareholder-funded deductible in the amount of 5 percent of up to \$1 billion in claims annually not to exceed \$50 million; (3) adjustment of revenue requirements for future years based on estimated claims activity and the recovery of any potential undercollection if necessary over a number of years after the 2023 GRC period concludes; (4) continuation of the RTBA with modifications necessary to implement the self-insurance framework described in the settlement; and (5) a Tier 2 advice letter process to support report on and calculate revenue requirements and handle other issues over the course of the 2023 GRC period.	
7	Gas Storage Balancing Account (GSBA): Tracks and records actual expenses and capital revenue requirements based on actual capital expenditures over the 2019 GT&S rate case cycle (2019-2022), compared to the revenue requirements based on the adopted capital expenditures for PG&E's natural gas storage facilities. Upon completion of a reasonableness review in PG&E's next rate case, disposition of the balances will be trued-up in rates. Modification: True-up balances annually upon review and approval of costs through a tier 2 advice letter rather than true-up at the end of funding cycle as part of next rate case. Decision Authorizing Account: D.19-09-025	In the 2019 Gas Transmission and Storage (GT&S) Rate Case, the Commission adopted the GSBA as a two-way balancing account given the significant regulatory uncertainty regarding gas storage regulations and requirements. In this proceeding, PG&E is proposing to retain the GSBA, but to modify the GSBA review process starting in 2023. Specifically, PG&E proposes filing annually a Tier 2 advice letter (AL) 90 days after the recorded costs for a year are final and that if no party protests, Commission staff can review and approve the costs through the advice letter. If parties do protest, they can request a change to a Tier 3 AL or an application if the circumstances warrant. This would replace the current process which requires	Opening Testimony: PG&E-03, p. 7-61, line 14 to p. 7-63, line 11. Rebuttal: PG&E-16-E, p. 7A-31, line 23 to p. 7A-33, line 16. Brief: Section 3.6.10

Table C-2			
Summary of Contested Balancing and Memorandum Accounts that PG&E Proposes Continuing with Modifications			
	Account	Summary of PG&E's Proposal	Location where Account is Discussed in PG&E's Opening Testimony, Rebuttal Testimony and Brief
		an application for GSBA costs to be addressed or that GSBA costs be addressed in the next rate case.	

Table C-3 PG&E's Proposed New Balancing and Memorandum Accounts – Contested			
	Account	PG&E's Position	Location where Account is Discussed in PG&E's Opening Testimony, Rebuttal Testimony and in the Brief
1	Catastrophic Event Straight-Time Labor Balancing Account (CESTLBA): PG&E has included a forecast of CEMA straight-time (ST) labor and overheads in this GRC and proposes to track and record the difference between actual and adopted ST labor costs associated with CEMA-eligible events in this account. Over-time labor associated with CEMA events will continue to be recorded to the CEMA.	PG&E proposes to recover straight time (ST) labor costs associated with its repair and restoration activities for Catastrophic Emergency Memorandum Account (CEMA)-eligible events through a new two-way balancing account referred to as the CESTLBA. If this proposal is approved, PG&E would stop recording CEMA ST labor costs to the CEMA, and PG&E's CEMA applications would only seek recovery of other non-labor-related expense, capital expenditures, certain limited overheads, and overtime and double time labor costs associated with PG&E's repair and restoration activities following a CEMA-eligible event. Under the proposed two-way balancing account, the CESTLBA will be trued up annually through PG&E's annual electric and annual gas true up advice letters. PG&E made this proposal to avoid future misunderstanding around the incrementality and recovery of CEMA ST labor costs, to simplify future CEMA recovery applications, and to account for the variability of CEMA-eligible catastrophic events occurrences.	Opening Testimony: P&GE-04, p. 6-26, lines 3-14. Rebuttal: PG&E-17, p. 6-9, line 9 to p. 6-15, line 21. Brief: Section 4.6.3

Table C-3

PG&E's Proposed New Balancing and Memorandum Accounts – Contested

2	Helms Capacity Memo Account (HCMA): PG&E proposes this account to record incremental expenses and capital revenue requirements associated with actual capital additions related to uprating the existing units at the Helms Pumped Storage Facility. Costs may include planning, engineering, permitting, equipment upgrades, testing, and other reasonable expenditures to implement the uprate project. PG&E has not developed a forecast of the costs of the project yet, and as such, the costs are not included in this GRC forecast. Recovery of costs recorded in the HCMA would be through a future GRC or other application.	PG&E proposes to establish the HCMA to record costs in connection with the uprate of the three existing units at Helms Pumped Storage Facility (Helms). The project is still in preliminary phases of analysis, but the Helms Uprate has an expected-case scenario of 1 unit coming online in 2027, 1 unit in 2028, and 1 unit in 2029. PG&E has not yet developed a detailed scope, schedule and forecast for this unique project but is evaluating alternatives in response to the CPUC's identified need for incremental long duration storage. To achieve online dates in 2027 through 2029 for the three units, work on the uprate project will occur in the 2024-2026 time period. While the uprated units may not be operational until 2027 or beyond, without the memorandum account, PG&E doesn't have the opportunity to request recovery of costs for this project through a future application. Does not reflect the agreement reached between PG&E and TURN reflecting a complete resolution of disputed Energy Supply issues between PG&E and TURN included in Appendix E.	Opening Testimony: PG&E-05, p. 8-17, line 24 to p. 8-18, line 18. Rebuttal: PG&E-18, p. 8-12, line 30 to p. 8-14, line 23. Brief: Section 5.8.3

Table C-4 Balancing Accounts and Memorandum Accounts PG&E Proposes Closing – Contested			
	Account	PG&E's Position	Location where Account is Discussed in PG&E's Opening Testimony, Rebuttal Testimony and Brief
1	Transmission Integrity Management Program Memorandum Account (TIMPMA): Tracks costs associated with any new transmission integrity management statutes. PG&E is requesting to modify the TIMPBA to become a two-way balancing account that would include recording of actual costs resulting from new TIMP regulations and rendering the TIMPMA unnecessary. Decision Authorizing Account: D.19-09-025; D.16-06-056	PG&E currently has a one-way balancing account for TIMP related costs that occur during the 2019 GT&S Rate Case period (i.e., 2019-2022). The TIMPBA was approved by the Commission in the 2019 GT&S Rate Case decision. PG&E also has a memorandum account referred to as the TIMPMA. The TIMPMA was first established by the Commission in the 2015 GT&S Rate Case decision (D.16-06-056) and is used to record any costs “associated with any new transmission integrity management statutes or rules, or new or changed interpretation by a regulatory body of transmission or integrity management statutes or rules.” PG&E proposes that the TIMPBA be converted to a two-way balancing account and that the TIMPMA be eliminated. As an alternative, if the TIMPBA remains a one-way balancing account, PG&E proposed the TIMPMA be modified to track costs above adopted amounts related to existing TIMP regulations given the mandatory compliance nature of the costs and uncertainty related to additional changes in regulation.	Opening Testimony: PG&E-03, p. 5-15, line 7 to p. 5-20, line 2. Rebuttal: PG&E-16-E, p. 5-78, line 25 to p. 5-83, line 7. Brief: Section 3.4.7
2	Internal Corrosion Balancing Account (ICBA): Tracks the difference between the revenue requirement based on adopted capital expenditures for the Internal Corrosion Program and the revenue requirement associated with actual capital expenditures. PG&E can develop a reasonable forecast of the program, which is included as part of this GRC, rendering the account unnecessary. Decision Authorizing Account: D.19-09-025	The 2019 GT&S Final Decision established the one-way Internal Corrosion Balancing Account (ICBA) for capital expenditures in the IC Program in MAT 3K1. The stated rationale for this decision was that PG&E's 2019 GT&S application did not explain with adequate detail its methodology for calculating its capital forecast. PG&E's 2023 2026 capital cost forecast for capital internal corrosion is based on actual pipe replacement data that is utilized across multiple chapters of this application. The complete details of the pipe replacement cost curves are provided in workpapers.	Opening Testimony: PG&E-03, p. 9-64, lines 15-27. Rebuttal: PG&E-16-E, p. 9-21, line 25 to p. 9-22, line 29. Brief: Section 3.14.3.2

Table C-4 Balancing Accounts and Memorandum Accounts PG&E Proposes Closing – Contested			
	Account	PG&E's Position	Location where Account is Discussed in PG&E's Opening Testimony, Rebuttal Testimony and Brief
3	In-Line Inspection Memorandum Account (ILIMA): Tracks the revenue requirement associated with the actual capital expenditures for Traditional In-Line Inspection (ILI) upgrade projects above the total authorized 48 projects, and actual expenses incurred for the associated initial Traditional ILI runs and Direct Examination and Repair resulting from the initial run. PG&E can reasonably forecast the costs of the ILI program and has included that forecast in this GRC, rendering both this memorandum account and the one-way ILIBA (see below) unnecessary. Decision Authorizing Account: D.19-09-025	The ILIBA records capital costs for the 48 Traditional ILI Upgrade projects adopted for the 2019 Gas Transmission and Storage (GT&S) rate case period (2019-2022). The ILIMA records capital costs incurred for projects completed above the 48 adopted ILI upgrades, the associated initial assessments and Direct Examination and Repair (DE&R) expenses, as well as all reassessment expenses and associated repairs. These accounts were adopted in the 2019 GT&S Rate Case primarily to address concerns that PG&E would not be able to complete more the 18 ILI Upgrade projects per year that it was forecasting. Thus, the Commission set the authorized number of ILI Upgrades at 12 per year for the four-year 2019 GT&S rate case period but provided PG&E to opportunity to do more ILI Upgrades and record these costs in the ILIMA. In this proceeding, PG&E is proposing to perform 12 ILI Upgrades per year, consistent with the Commission's direction in the 2019 GT&S Rate Case, thus there is no need for the ILIBA and ILIMA structure adopted in that proceeding. Because there is no longer a need for the ILIBA and ILIMA, PG&E is proposing to eliminate both the ILIBA and ILIMA. Costs associated with Traditional ILI Upgrades would be included in PG&E's approved revenue requirement in this proceeding, rather than being recorded in the ILIBA. Costs associated with initial ILI runs, ILI re-assessments, and any associated repairs would be accounted for in the Transmission Integrity Management Program Balancing Account (TIMPBA) because these costs relate to a TIMP program.	Opening Testimony: PG&E-03, p. 5-36, line 28 to p. 5-38, line 2. Rebuttal: PG&E-16-E, p. 5-83, line 8 to p. 5-86, line 19. Brief: Section 3.4.8

Table C-4 Balancing Accounts and Memorandum Accounts PG&E Proposes Closing – Contested			
	Account	PG&E's Position	Location where Account is Discussed in PG&E's Opening Testimony, Rebuttal Testimony and Brief
4	Internal Corrosion Direct Assessment Memorandum Account (ICDAMA): Tracks actual expenses incurred for the Internal Corrosion Direct Assessment Program. PG&E has completed the units of work requested in the 2019 GT&S rate case, rendering the account unnecessary. Decision Authorizing Account: D.19-09-025	The ICDAMA was adopted by the Commission in the 2019 Gas Transmission and Storage (GT&S) Rate Case to track recorded internal corrosion direct assessment (ICDA) expenses for the 2019-2022 rate case period. This account was adopted in the 2019 GT&S Rate Case primarily to address concerns that PG&E had not completed ICDA work in the 2015 GT&S rate case period in order to instead fund more Transmission Integrity Management Program (TIMP) strength tests. Thus, the Commission established this memorandum account to track ICDA work for future rate recovery consideration. PG&E has completed the units of ICDA work authorized in the 2019 GT&S Rate Case, thus eliminating any uncertainty about PG&E's conduct of this work. Since the basis for establishing and maintaining this memorandum account no longer exists and is no longer applicable, PG&E proposes to eliminate the ICDAMA and allow the ICDA recorded costs to flow through the TIMP Balancing Account (TIMPBA) given that these costs are Subpart O (49 Code of Federal Regulations, Part 192, Subpart O) TIMP related expenses.	Opening Testimony: PG&E-03, p. 5-50, lines 1-15. Rebuttal: PG&E-16-E, p. 5-86, line 20 to p. 5-87, line 21. Brief: Section 3.4.9
5	In-Line Inspection Balancing Account (ILIBA): Tracks the difference between the capital revenue requirement based on adopted capital expenditures for the Traditional In-Line Inspection (ILI) Upgrade program and the revenue requirement associated with actual capital expenditures for the 48 authorized Traditional ILI projects. PG&E can reasonably forecast the costs of the ILI program and has included that forecast in this GRC, rendering both this one-way balancing account and the ILIMA unnecessary. Decision Authorizing Account: D.19-09-025	The ILIBA records capital costs for the 48 Traditional ILI Upgrade projects adopted for the 2019 Gas Transmission and Storage (GT&S) rate case period (2019-2022). See In-Line Inspection Memorandum Account (ILIMA) on line 3 above.	Opening Testimony: PG&E-03, p. 5-36, line 28 to p. 5-38, line 2. Rebuttal: PG&E-16-E, p. 5-83, line 8 to p. 5-86, line 19. Brief: Section 3.4.8

Appendix D

PG&E's Results of Operations Model

The Results of Operations (RO) Model generates forecasted Revenue Requirements (RRQ) based on inputs in three main input modules that consist of: (1) Expense Component; (2) Capital Component and (3) Tax module. The Expense, Capital, Tax modules include various inputs that can be adjusted in the revenue requirement calculation. Some of the key inputs where adjustments can be made include:

- Cost Forecast for Expense and Capital by program
- Depreciation rates;
- Unbundled cost categories (UCCs) between major functional groups (i.e. distribution, generation, etc.);
- Lead-lag portion of working cash; and,
- Tax rates.

Appendix D includes four slide decks prepared by PG&E and is meant to provide a high-level explanation of different components of the RO Model and the individual modules. The slide decks are meant to accompany the RO Model User Manual (included as part of the RO Model) that provides detailed instructions about how to input data into and update the different modules and spreadsheets.¹ Because the slide decks are meant to be presented as part of an oral presentation, much of the information on the slides are summary in nature. Below we provide a summary of the four slide decks and each of the slides in these decks.

Slide Deck 1 - Calculation of Revenue Requirement (08/18/2021)

Slide 1A – Calculation of Revenue Requirement

Introduction to the material covered in the Calculation of Revenue Requirement presentation. Calculation of the revenue requirement is described in PG&E-10, Chapter 17.

Slide 1B - RO Model Detail Flow

¹ The Energy Division and Commission Staff have copies of these materials.

Flow chart demonstrating how data flows through the RO Model.

- The yellow boxes represent inputs from GRC Exhibit 3 to Exhibit 10 (e.g. expense and capital forecasts, tax information, post test-year forecasts, etc.);
- The orange boxes are the three RO Model modules;
- The blue boxes are sub-modules; and
- The green box is RO Processing Module.

Slide 1C – RO Model Primary Input Adjustment Areas

Slide 3 is meant to be accompanied by RO User Manual. It provides an overview of where users can make adjustments in the RO Model.

Users can filter the capital and expense costs by PG&E exhibit and chapter which will generally tie back to the Exhibit 3 to Exhibit 9 expense and capital forecasts.

- Lists the Capital Module adjustment items – Adjustments can be made to the capital expenditure forecasts at the planning order level. An example of the programmatic work planning orders is shown on Slide 2F. Depreciation parameters can be adjusted at Asset Class level as described in Exhibit (PG&E-10), Chapter 11.
- Lists the Expense Module adjustment items and process - The RO Model requires that forecast expense data be translated from the SAP view (major work categories and MAT codes) to a FERC account view. This process is described in Exhibit (PG&E-10), Chapter 2.
- Lists the Global Module adjustment items – Includes working cash (PG&E-10, Chapter 14), cost of capital, escalation (PG&E-12, Chapter 3 and PG&E-33, Chapter 2) and Revenues, Fees and Uncollectibles (RF&Us).

Slide 1D - RO Model Components Feeding Input Files

High level flow chart demonstrating an RO Model run. The RO Model run starts with expense and administrative and general (A&G) files, then to capital and finishes with the tax files.

The names of individual input files in the RO Model are provided below each module on the slide. The RO User Manual provides instructions for how to input data into each file, and each tab within the file, and run the modules.

Slide Deck 2 - Calculation of Revenue Requirement – Capital Module (09/08/021)

Slide 2A – Calculation of Revenue Requirement Capital Module

Introduction to the material covered in the Calculation of Revenue Requirement, Capital Module presentation.

Slide 2B – Capital Revenue Requirement

Shows the high level formula and key components for calculating the capital revenue requirement (RRQ).

Slide 2C – Capital Module Flow

Describes the files that flow into the capital module and files output from the capital module. Provides the names of individual input and output files. More information about the files, and the individual tabs within each file, is provided in the RO User Manual.

Slide 2D – Capital Expenditures

Defines what is included in and excluded from capital expenditures in the RO Model.

- Electric, Gas and Common Plant is described in Exhibit (PG&E-10), Chapter 10.

Slide 2E – Planning Order Types and Operative Date Requirement

Identifies the two types of planning orders (PO) used in capital projects and their respective operative dates used in the capital model: PO Type 55 and PO Type 57. Explains what is included or required in each type. What POs in the Capex tab of the Capital Model is and represents.

- Planning order level detail for capital projects and programs is included in the workpapers supporting the line of business testimony (Exhibits PG&E 3-9).

Slide 2F – Example of Programmatic Work PO

Example of a programmatic work PO, PO Type 57.

Slide 2G – Capital Functional Groups

Describes how POs are summarized by functional group and asset classes (FERC accounts) which are converted into capital additional at the asset class to build the forecast plant balance at the asset class level.

Slide 2H – Capital Expenditures to Plant

Flow chart showing how capital expenditures move through the RO Model to become net additions to plant.

- More information about capital expenditures is provided in Exhibit (PG&E-10), Chapter 10.

Slide 2I – Retirements

Explains the three different kinds of retirements included in the capital module: normal retirements, vintage retirements and UG and OH retirements.

- More information about retirements is provided in Exhibit (PG&E-10), Chapter 10.

Slides 2J - Depreciation Rates and Expense

Defines what is included in depreciation rates. Identifies where depreciation is addressed in the RO Model.

- More information about depreciation is provided in Exhibit (PG&E-10), Chapters 11 and 12.

Slide 2K - Depreciation Rates and Expense Graph

Graphic showing investment recovery over time.

Slide 2L – Plant and Accumulated Depreciation Walk

Describes the calculation of how plant and accumulated depreciation is derived in the capital module.

Slide 2M – Common Cost Allocation

Describes how PG&E allocates common costs based on the O&M labor allocation factors.

- More information about common cost allocation is provided in Exhibit (PG&E-10), Chapter 10.

Slide Deck 3 - Capital Module – Income and Property Tax Module (09/15/2021)

Slide 3A – Capital Module and Income and Property Tax Module

Introduction to the slide deck

Slide 3B – Other Rate Base Items

Other rate base items that are not driven by capital expenditures provided in Exhibit 3 to Exhibit 9. Item include customer advances, Materials and Supplies and one time adjustments such as depreciation refund for gas storage.

- More information about other rate base items is provided in Exhibit (PG&E-10), Chapter 15.

Slide 3C - Capital Revenue Requirement: Income and Property Tax Emphasis

Shows the formula for calculating the capital revenue requirement.

Slide 3D – Income and Property Tax Module Flow

Describes the files that flow into the income and property tax module and files output from the income and property tax module. Provides the names of individual input and output files. More information about the files, and the individual tabs within each file, is provided in the RO Model User Manual.

Slide 3E – Income and Property Tax Calculation

Provides an overview of the income and property tax calculations.

- More information about income and property taxes is provided in Exhibit (PG&E-10), Chapter 13.

Slide 3F – Income and Property Tax Module, Key Capital Inputs

Lists the key capital inputs into the income and property tax module.

Slide 3G – Income and Property Tax Module, Outputs

Lists the outputs from the income and property tax module: supporting taxable income and tax expense; supporting tax credits and amortization of excess deferred taxes; and supporting rate base.

Slide Deck 4 – Global Module and RO Processing Module (09/22/21)

Slide 4A – Global Module and RO Iterative Module

Introduction to the slide deck.

Slide 4B – Global Module and RO Iterative Module

Chart showing the flow of the overall RO Model.

Slide 4C – RO Processing Module Iterative Calculations Flowchart

Chart showing the iterative calculations flow of the RO Processing Module.

Slide 4D – Cost of Service Formula

Provides the cost of service formula. Please note, the cost of service formula in Section 1.4.2.3 uses the term “O&M” for all operating and maintenance expenses, administrative and general expenses, and taxes other than income tax. The cost of service formula on slide 4D uses the term “E” to represent operating and maintenance expenses, administrative and general expenses, and taxes other than income tax.

More information about calculating the revenue requirement is provided in Exhibit (PG&E-10), Chapter 17.

Slide 4E -RO Output

Shows the output from the RO Model, annotated to identify each component of the cost of service formula in the results of operations output page.

Slide 4F – RO Ratebase

Shows the output from the RO Model that make-up total ratebase.

Slide 4G - Income and Property Tax

Shows the output from the RO Model summarizing federal and state income taxes.

Appendix D

2023 GRC – PG&E RO Model



Slide Deck 1: Calculation of Revenue Requirement- 08/18/2021

Slide Deck 2: Calculation of Revenue Requirement, Capital Module 09/08/21

Slide Deck 3: Capital Module- Income and Property Tax Module 09/15/2021

Slide Deck 4: RO Iterative Module – 09/22/2021



2023 GRC – PG&E RO Model

Exhibit (PG&E-10), Chapter 17
Calculation of Revenue Requirement

Slide Deck 1
Calculation of Revenue Requirement

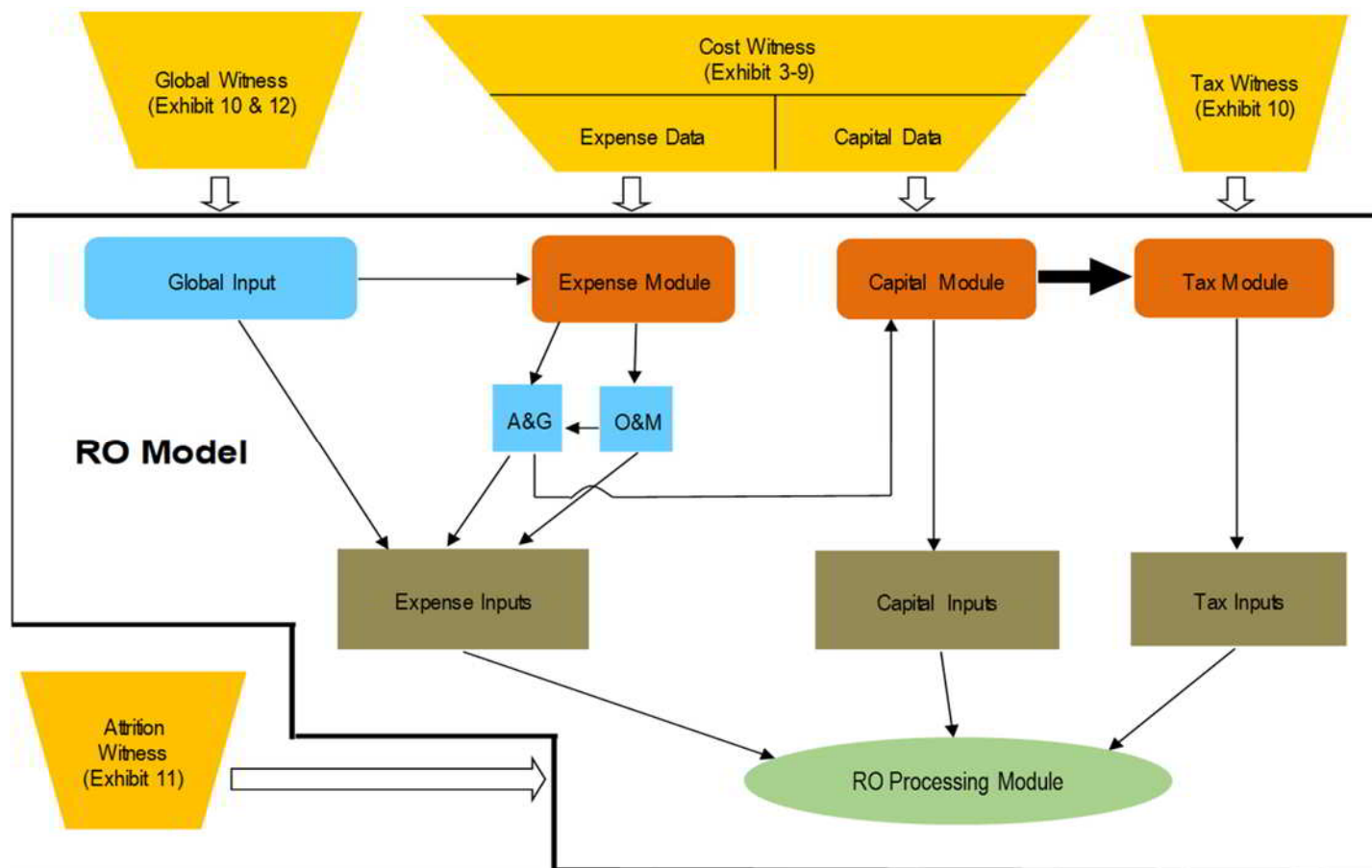




Slide 1A – Calculation of Revenue Requirement

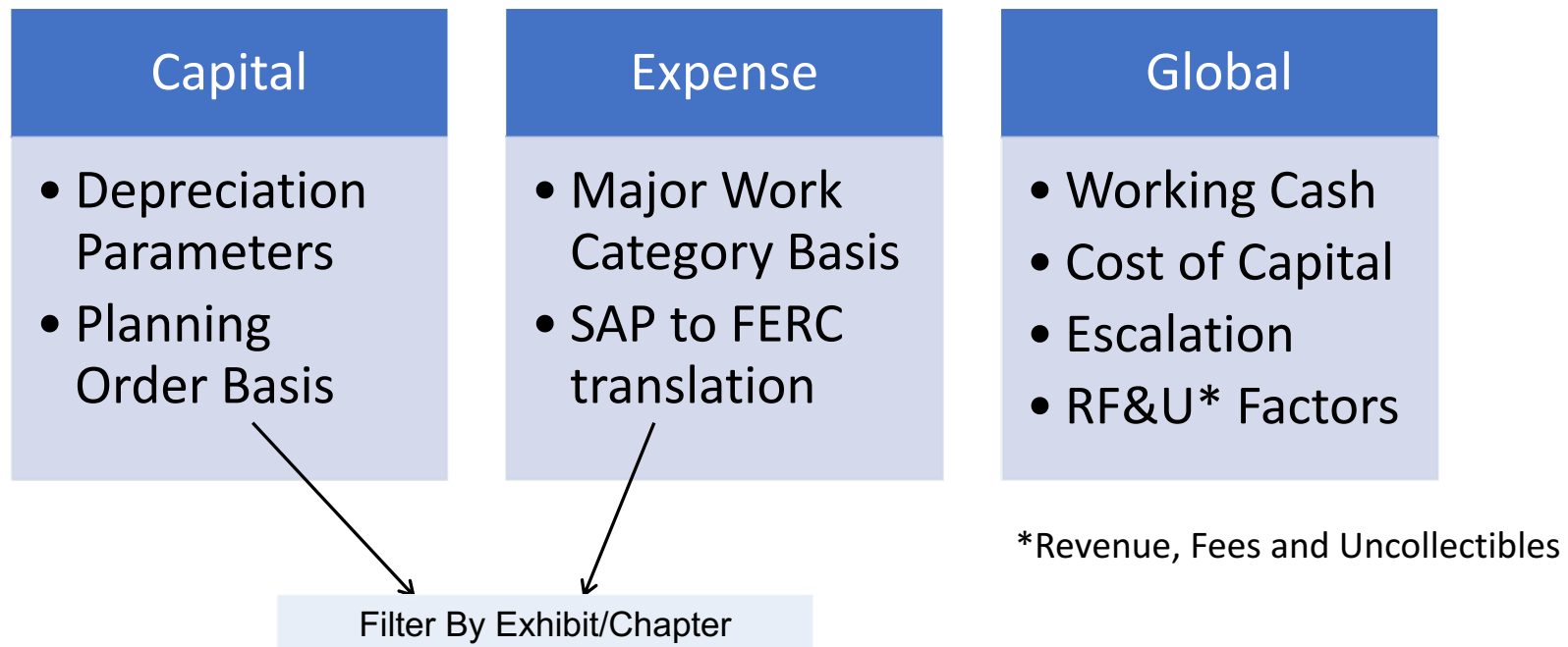
- a. Overview of the different RO modules/ RO items - Flow chart
- b. Folders and filenames - copy and process to run
 - ☐ Enable macros
 - ☐ Iterative calculation
 - ☐ Opening files
- c. 3 different RO iterative Excel models
- d. UCC list overview & GT&S UCC models
- e. Other terminology - Functional codes, Asset classes and Tax codes that are used in the models
- f. How to change inputs
- g. Confidentiality for UCC 109
- h. Using comparison file after running the model

Slide 1B – RO Model Detail Data Flow





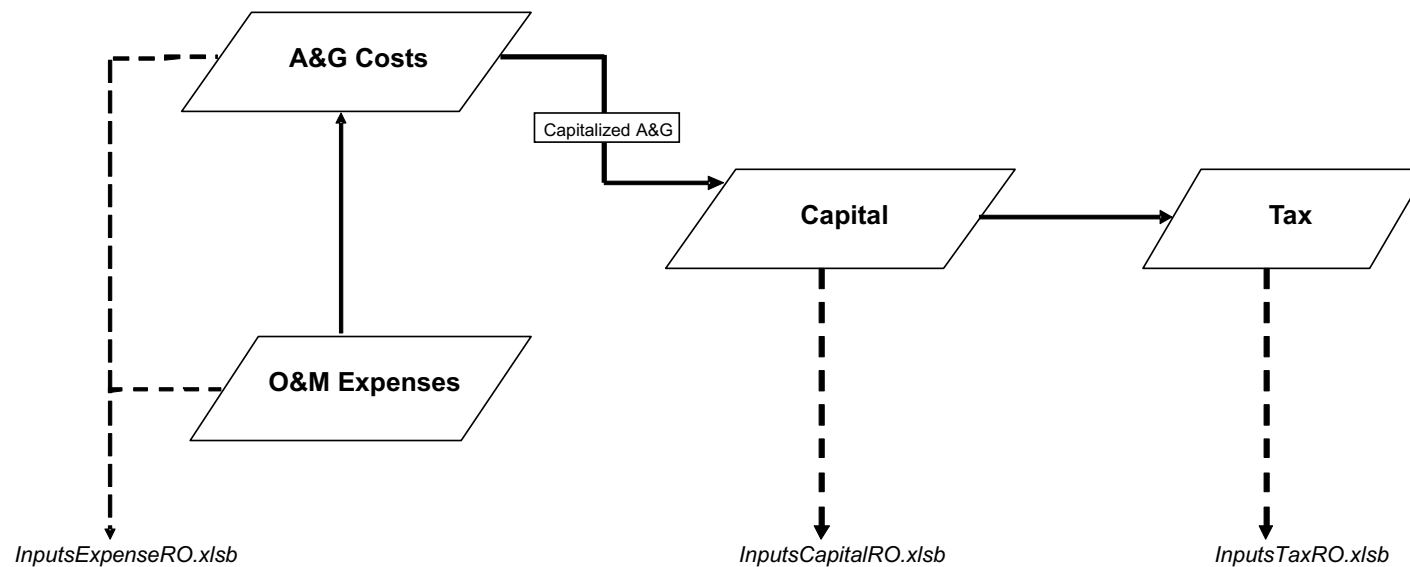
Slide 1C – RO Model Primary Input Adjustment Areas





Slide 1D – RO Model Components Feeding Input Files

PRIMARY RO COMPONENT DATA INTERFACE DIAGRAM



2023 GRC – PG&E RO Model

**Exhibit (PG&E-10), Chapter 17
Calculation of Revenue Requirement**

**Slide Deck 2
Calculation of Revenue Requirement
Capital module**





Slide 2A – Calculation of Revenue Requirement Capital Module

- Overview of Capital module
 - Capital RRQ formula
 - Life cycle of asset – Capex to Adds to Plant to Retirements
 - Capital module flow
 - Capital Expenditure and Different types of Planning orders
 - Functional groups and link to FERC accounts and asset classes
 - Retirements
 - Depreciation expense
- Inputs and Outputs of Capital model
- Tab by tab walk through
- Example adjustments



Slide 2B – Capital Revenue Requirement

Capital RRQ = D + T + R (RB)

D – Depreciation

T- Taxes (Income and Property)

R (RB) – Return on Rate base

Rate base =

Plant

+ Materials and Supplies

+ Working Cash

+/- Deferred Taxes

- Customer Advances

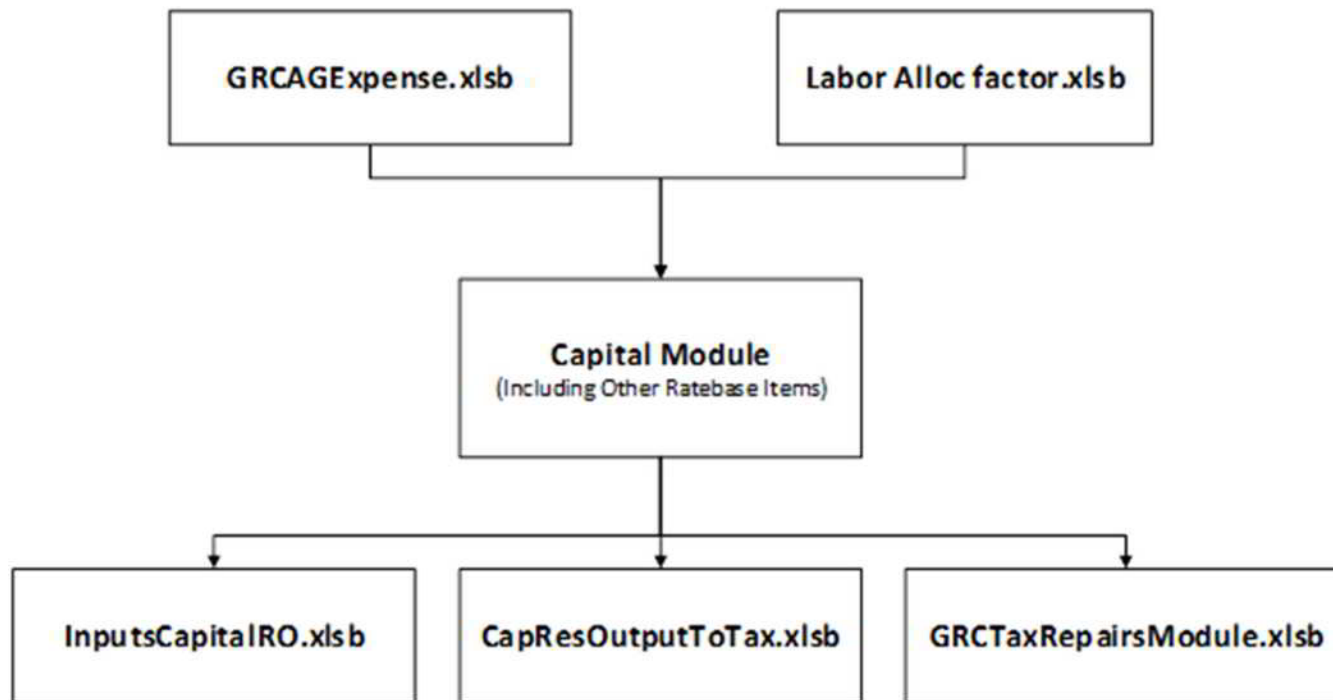
- Accumulated Depreciation

In the **capital module**, we will cover Depreciation, Plant, Accumulated Depreciation, Materials and Supplies and Customer Advances



Slide 2C – Capital Module Flow

Capital module includes CapitalModel.xlsb and OtherRatebase.xlsb.





Slide 2D – Capital Expenditures

- Capital expenditures are presented in Exhibit 3 to Exhibit 9 at a planning order level
- Capital expenditures presented in these exhibits include:
 - Labor and Material costs for Installation of new assets
 - Cost of Removal of old assets
 - Capitalized A&G cost such as Medical benefits
 - AFUDC for orders >30 days
 - Capitalized Pension
- Pension costs are not recovered in the GRC and hence the capitalized portion of Pension is removed from capital orders in the CapitalModel.xlsb.
- See tab CapAandG for details on Capitalized pension adjustment



Slide 2E – Planning Order Types and Operative Date Requirement

Type 55 planning orders

- Projects with an estimated install / construction period < 30 days
- **NOT** required to have operative dates because these orders are considered “operative as installed”
- Standing orders or generally routine, repetitive, low cost work

Type 57 planning orders

• Specific project with an estimated install / construction period > 30 days • <u>REQUIRE</u> operative dates to properly calculate revenue requirements	• Programmatic work: generic or repetitive work with construction period > 30 days • <u>DO NOT REQUIRE</u> operative dates • Annual Capex will spread to each month based on historical seasonality of capital additions. • Seasonality for programmatic work determined by MWC/ MAT



Slide 2F – Example of Programmatic Work PO

Before:					
		Capex			
Planning order	Planned operative date	2023	2024	2025	2026
PO 1	06/2023	100			
PO 2	06/2024		105		
PO 3	06/2025			107	
PO 4	06/2026				110
After:					
		Capex			
Planning order	Planned operative date	2023	2024	2025	2026
PO 1 - programmatic	N/A - not required	100	105	107	110

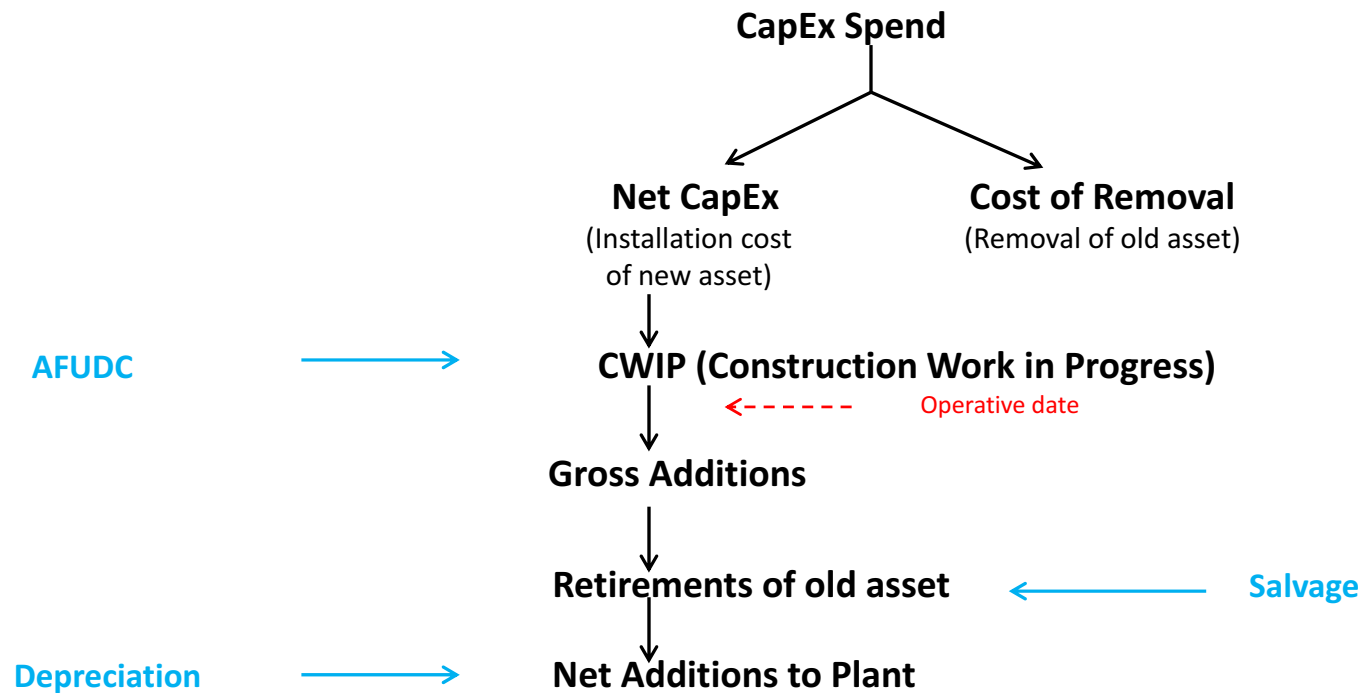


Slide 2G – Capital Functional Groups

- Each Planning order is assigned a functional group and UCC based on the work it represents by the Plant witness
- Functional groups is a collection of asset classes or FERC accounts
- Functional group examples include
 - EDP – Electric Distribution Plant
 - GDP – Gas Distribution Plant
 - GTP – Gas Transmission Plant
 - EHP - Electric Hydro Plant
 - ENP - Electric Nuclear Plant
 - CST – Common Structures
- The full list of Capital functional groups is provided in the manual
- The functional group dollars is then split to Asset classes (FERC Accounts) based on historical spread (See Tab: lkpFactorByFuncGrp for factors)
- Capital Additions at planning order level is converted to capital additions at asset class level to build the forecast plant balance at asset class level.



Slide 2H – Capital Expenditures to Plant



- AFUDC (Allowance for Funds during construction) is calculated based on CWIP.
- Depreciation of the capital asset does not begin until it is determined to be used and useful and recorded as plant.



Slide 21 – Retirements

There are two types of retirements included in the 2023 GRC CapitalModel:

1. Normal retirements:

- Assets that are retired from service and replaced with new assets
- Calculated as a % (factor) of new forecast capital additions in the capital model
- The factors are based on functional group or type of asset
- See Tab: lkpFactorByFuncGrp for factors

2. Vintage Retirements:

- Vintage retirements represent certain common and general plant assets purchased in large volume such as computers, telecommunications equipment, office equipment, software and furniture that will be retired according to a predetermined schedule that reflects their estimated useful service lives.

3. Overhead Retirements for Undergrounding

- These are special retirements where the installation of asset does not lead to a like for like asset retirement. When undergrounding assets are installed, existing overhead assets would be retired and conversion factor for underground asset installation to OH asset retirement is provided in Capitalmodel.xlsb tab “UG_OH_Rets_Reclass”

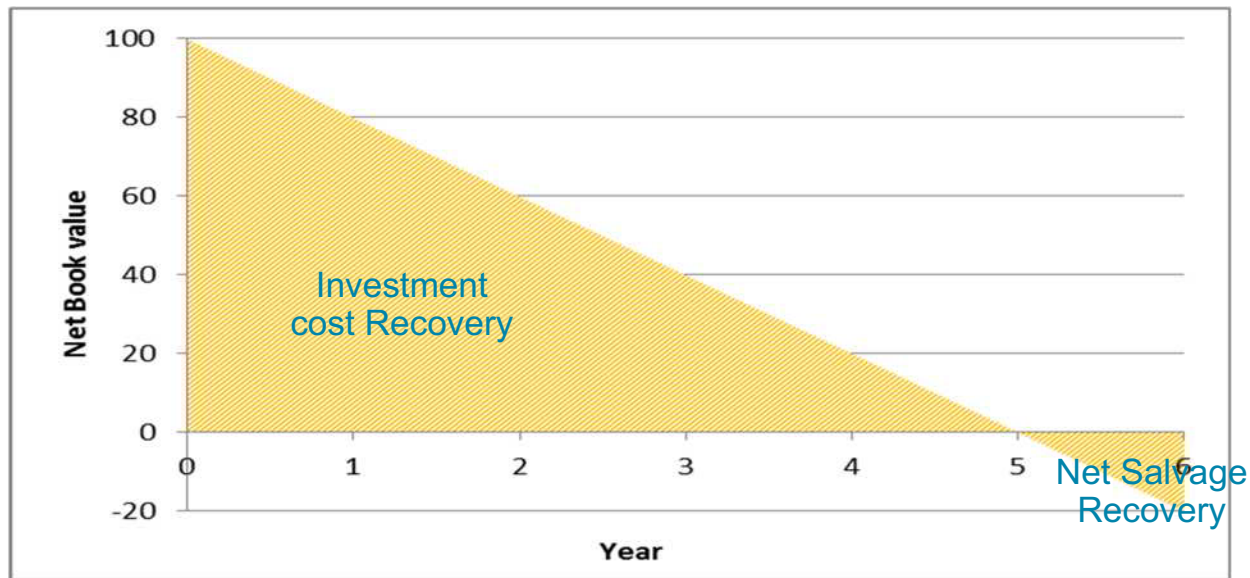


Slide 2J – Depreciation Rates and Expense

- Depreciation rates proposal by asset class is presented in Exhibit 10, Chapter 12
- Depreciation rates include Life rate, Cost of Removal rate and Salvage rate
- Depreciation expense is calculated monthly in the CapitalModel.xlsb using Plant and Depreciation rates by asset class
- Tab Depn_ScheduleAdj allows for changes in depreciation rates
- Depreciation expense is an increase to Accumulated Depreciation and hence a decrease to rate base



Slide 2K – Depreciation Rates and Expense



Net salvage = gross salvage – cost of removal.

Cost of removal is typically much larger than gross salvage

Gross Salvage is calculated as a % of normal retirements in the model



Slide 2L – Plant and Accumulated Depreciation Walk

Beginning Plant

+ Gross Capital Additions

- Retirements

= Ending Plant

Beginning Depreciation Reserve

+ Depreciation expense (Life, salvage)

+ Cost of Removal expense

- Retirements

- Cost of Removal Spend

+ Gross Salvage

= Ending Depreciation Reserve



Slide 2M – Common Cost Allocation

- All Common, General and Intangible plant is allocated to the functional areas based on O&M labor allocation factors
- The labor allocation factors are provided in labor alloc factor.xlsb
- No direct assigned Common/General/Intangible Plant starting 2023 GRC. Refer Exhibit 10, chapter 10 for discussion on the allocation methodology
- O&M labor Allocation factors is adjusted in 2025 and 2026 for Diablo Canyon Powerplant closure

2023 GRC – PG&E RO Model

**Exhibit (PG&E-10), Chapter 17
Calculation of Revenue Requirement**

**Slide Deck 3
Capital Module
Income and Property Tax Module**





Slide 3A – Capital Module and Income and Property Tax Module

- Walk through Capital model – asset class tabs
- Other Ratebase items
- Overview of Income & Property Tax module
 - Capital RRQ formula
 - Tax module flow
 - Income and Property Tax calculation
 - Inputs and Outputs of Tax module
- Tax models walkthrough



Slide 3B – Other Rate Base Items

Other rate base items are explained in PG&E Exhibit 10, Chapter 15

Following are the items covered in other ratebase items

Line no	Item	RO impact
1	Materials and Supplies	Increase to rate base through working capital
2	Customer Advances	Decrease to rate base
3	Cushion gas/Linepack gas	Increase to rate base through Plant
4	Utility Retained Generation - Regulatory Asset	Increase to rate base through Plant
5	Decommissioning Accrual/Spend	Decrease/Increase to rate base through Accumulated Depreciation
6	Depreciation refund for Gas Storage	Increase rate base through Accumulated Depreciation



Slide 3C – Capital Revenue Requirement: Income & Property Tax Emphasis

$$\text{Capital RRQ} = D + T + R \text{ (RB)}$$

D – Depreciation

T- Taxes (Income and Property)

R (RB) – Return on Rate base

Rate base =

Plant

+ Materials and Supplies

+ Working Cash

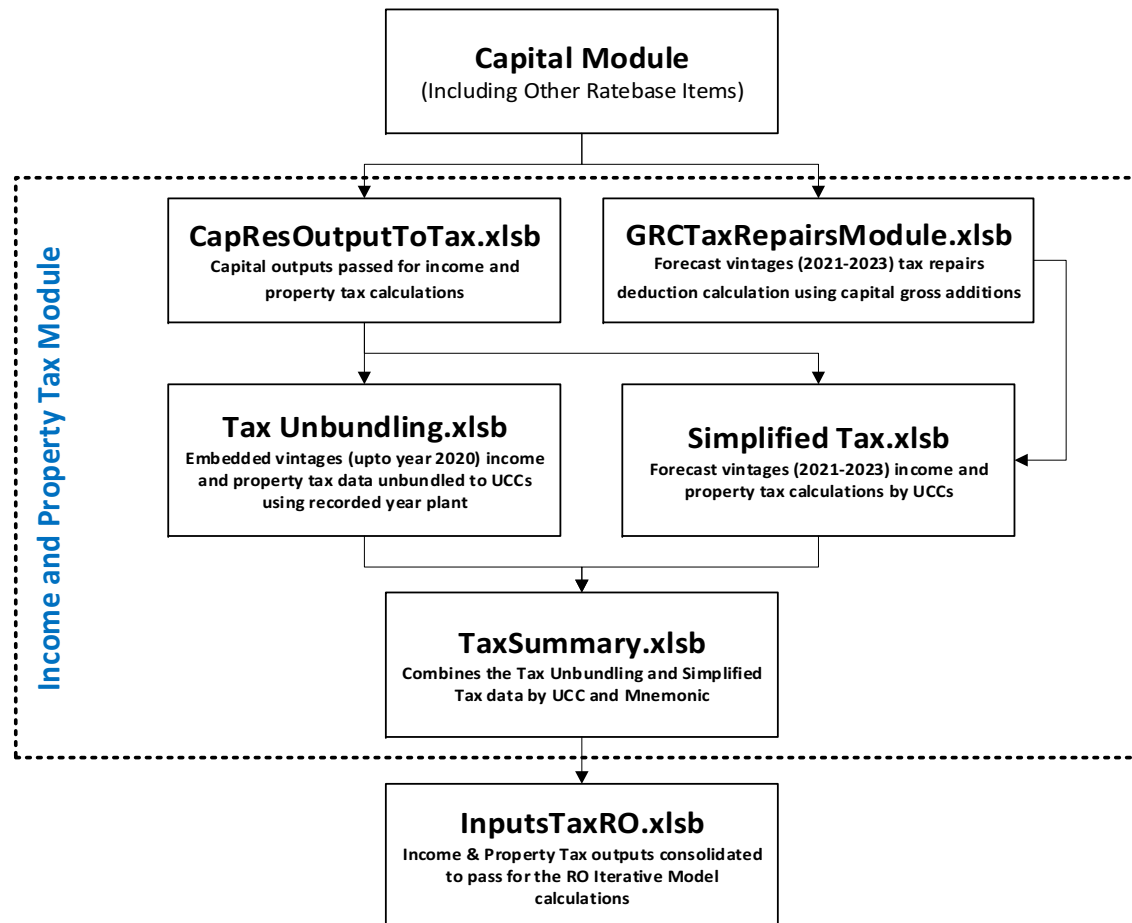
+/- Deferred Taxes

- Customer Advances

- Accumulated Depreciation



Slide 3D – Income and Property Tax Module Flow





Slide 3E – Income and Property Tax Calculation

The Income and Property Tax Module uses the following sources of data to compute CPUC jurisdictional tax expense including rate base items:

- The Power Tax System calculates GRC test year impacts from assets in service up to the recorded year. The Tax Unbundling file then unbundles this data to UCCs for use in the RO Iterative Model
- The Simplified Tax file and the Tax Repairs file calculates GRC test year impacts from assets placed in service in forecast years (2021 - 2023)
- The above sources are integrated by the Tax Summary file to compute combined tax expense and deferred taxes



Slide 3F – Income and Property Tax Module: Key Capital Inputs

- Recorded End of Year Plant
- Forecast Gross Additions
- Book Depreciation
- Adopted and Proposed Book Depreciation Rates
- Cost of Removal
- Decommissioning
- Regulatory Asset Accrual and Spending



Slide 3G – Income and Property Tax Module: Outputs

Supporting Taxable Income and Tax Expense

- Property Tax Adjustment
- Operating Expense Adjustment
- Federal and California Cost of Removal
- Vacation Pay Adjustment
- Mixed Service Cost Adjustment
- Federal & California Capitalized Interest Adjustment
- Federal & California Tax Depreciation, Gain & Loss Adjustment
- Federal & California Capitalized Inventory Adjustment
- Federal & California Repair Deduction
- Federal & California Capitalized Software Adjustment
- Federal & California Capitalized Interest – Deferred Tax Expense
- Federal & California Deferred Tax Expense – Vacation Pay
- Federal & California Tax Depreciation, Gain & Loss – Deferred Tax Expense
- Federal & California Miscellaneous Expense Adjustments
- Federal Preferred Dividend Adjustment

Supporting Tax Credits and Amortization of Excess Deferred Taxes

- Investment Tax Credit Adjustment to Rate Base
- Amortization of Excess Deferred Taxes
- Federal and State Tax Credits

Supporting Rate Base

- Average Deferred Tax Reserve – Capitalized Interest
- Average Deferred Tax Reserve – Vacation Pay
- Contributions in Aid of Construction Adjustment to Rate Base
- Average Deferred Tax Reserve – Depreciation, Gains and Losses

2023 GRC – PG&E RO Model

Exhibit (PG&E-10), Chapter 17
Calculation of Revenue Requirement

Slide Deck 4
Global Module
RO Processing Module



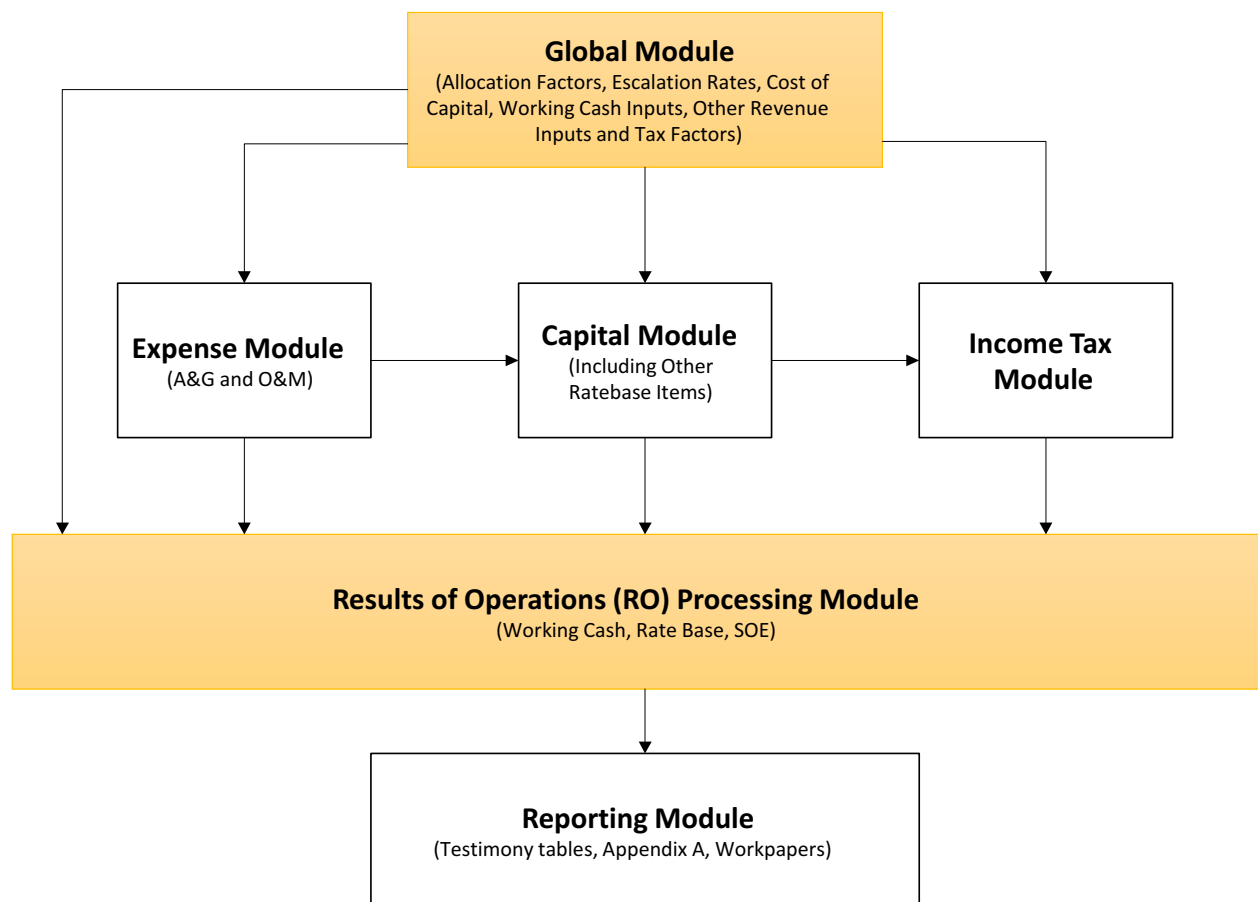


Slide 4A – Global Module RO Processing Module

- RO Model Flow
- Cost of Service Formula
- RO Output
- RO Rate Base (RB)



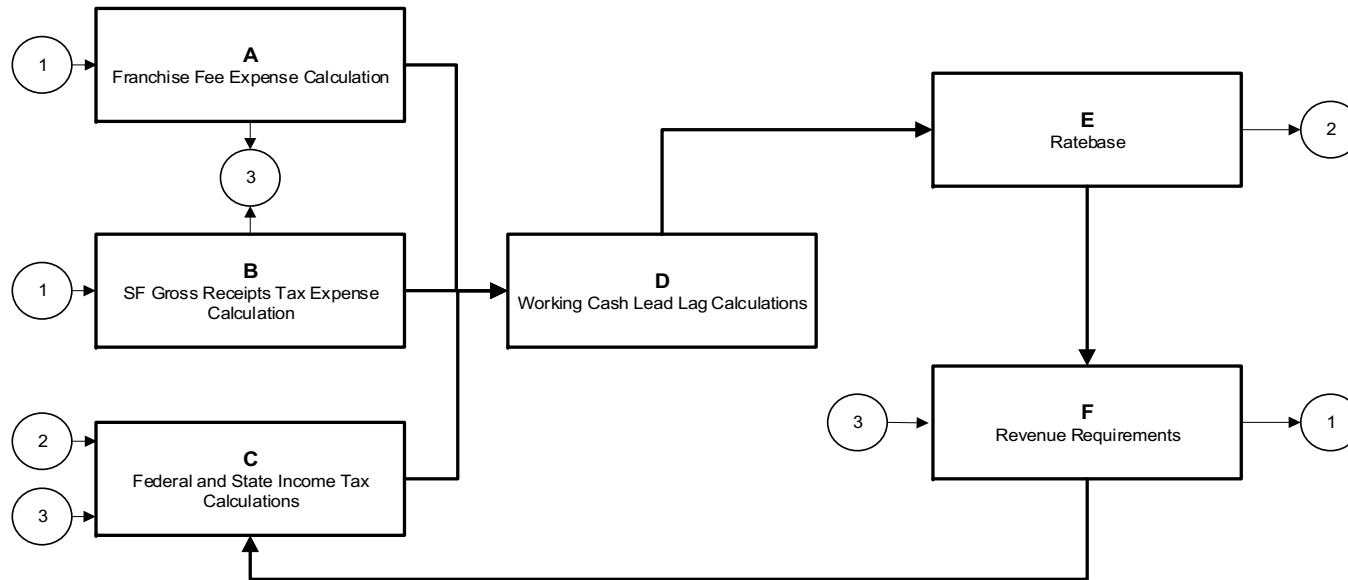
Slide 4B – RO Model Flow





Slide 4C – RO Processing Module Iterative Calculations Flowchart

Please note that the RO Processing Module uses the built-in iterative functionality of the Microsoft Excel application.



Connector Legend:

- 1 Revenue Requirements (F) impacts Franchise Fee expense (A) and SF Gross Receipts Tax expense (B)
- 2 Ratebase (E) impacts Income Taxes (C)
- 3 Franchise Fee expense (A), SF Gross Receipts Tax expense (B) and Income Taxes (C) impacts Revenue Requirements (F)



Slide 4D - Cost of Service Formula

$$\bullet \text{ RRQ} = \text{E} + \text{D} + \text{T} + r \times (\text{RB})$$

- **E** – All operating and maintenance expenses, administrative and general expenses, and taxes other than income tax.
- **D** – Book depreciation expense allowed in a given year for recovery of capital additions.
- **T** – Income taxes paid to federal and state governments.
- **r** – The allowed Return on Rate Base (RORB) direct input obtained from Cost of Capital (COC) proceeding.
- **RB** – Total capital investment in plant and equipment used to provide utility service.



Slide 4E - RO Output

Pacific Gas and Electric Company
2023 CPUC General Rate Case (Application) - Results of Operations
Electric and Gas Departments Summary
(Millions of Dollars)

Line	Description	Application	
REVENUE:			
1	Revenue Collected in Rates	15,461	→ RRQ
2	Plus Other Operating Revenue	276	
3	Total Operating Revenue	15,737	
OPERATING EXPENSES:			
4	Production / Procurement	602	→ E
5	Storage	34	
6	Transmission	793	
7	Distribution	2,905	
8	Customer Accounts	379	
9	Uncollectibles	46	
10	Customer Services	0	
11	Administrative and General	2,159	
12	Franchise & SFGR Tax Requirement	129	
13	Amortization	31	
14	Other Adjustments	40	
15	Subtotal Expenses:	7,119	
TAXES:			
16	Property	624	→ T
17	Payroll	145	
18	Business	2	
19	Other	32	
20	State Corporation Franchise	164	
21	Federal Income	280	→ T
22	Total Taxes	1,247	
23	Depreciation	3,798	→ D
24	Decommissioning	45	
25	Total Operating Expenses	12,210	→ r(RB)
26	Net for Return	3,528	
27	Rate Base	48,515	
RATE OF RETURN:			
28	On Rate Base	7.27%	
29	On Equity (Note 1)		

Line 2 – Global

Line 4 to Line 8 and Line 9 – O&M Model

Line 11 – A&G Model

Line 13 and Line 14 – Global Model

Line 16 – Income & Property Tax Module

Line 17 to Line 19 – Global Model

Tax Module

Capital Module

Line 2 – Global
Line 4 to Line 8 and Line 9 – O&M Model
Line 11 – A&G Model
Line 13 and Line 14 – Global Model
Line 16 – Income & Property Tax Module
Line 17 to Line 19 – Global Model

Tax Module

Capital Module

Note 1: Electric Distribution-related AB 1054 ROE is 0% and all other GRC ROE is at 10.25%.
See detailed functional workpapers supporting Exhibit (PG&E-10), Chapter 17.



Slide 4F - RO Ratebase (RB)

Pacific Gas and Electric Company
2023 CPUC General Rate Case (Application)
2023 Ratebase
Electric And Gas Departments Summary
(Millions of Dollars)

Line	Description	Application
	WEIGHTED AVERAGE PLANT:	
1	Plant Beginning Of Year (BOY)	88,437
2	Net Additions	3,374
3	Total Weighted Average Plant	91,811
	WORKING CAPITAL:	
4	Material and Supplies - Fuel	0
5	Material and Supplies - Other	556
6	Working Cash	1,557
7	Total Working Capital	2,112
	ADJUSTMENTS FOR TAX REFORM ACT:	
8	Deferred Capitalized Interest	14
9	Deferred Vacation	43
10	Deferred CIAC Tax Effects	352
11	Total Adjustments	409
12	CUSTOMER ADVANCES	95
	DEFERRED TAXES	
13	Accumulated Regulatory Assets	(6)
14	Accumulated Fixed Assets	3,277
15	Accumulated Other	0
16	Deferred ITC	158
17	Deferred Tax - Other	0
18	Total Deferred Taxes	3,428
19	DEPRECIATION RESERVE	42,294
20	TOTAL Ratebase	48,515



Slide 4G - Income and Property Tax Module

Pacific Gas and Electric Company
2023 CPUC General Rate Case (Application) - Income Taxes
Electric and Gas Departments Summary
(Millions of Dollars)

Line	Description	Application
1	Revenues	15,737
2	O&M Expenses	7,119
3	Other Decommissioning Expense	0
4	Superfund Tax	0
5	Taxes Other Than Income	803
6	Subtotal	7,815
	DEDUCTIONS FROM TAXABLE INCOME:	
7	Interest Charge Adjustment	984
8	Fiscal/Calendar Property Tax Adjustment	35
9	Operating Expense Adjustments	(90)
10	Repair Deduction	1,514
11	Removal Cost Adjustment	71
12	Vacation Pay Adjustment	(5)
13	Mixed Service Cost Adjustment	127
14	Subtotal Deductions	2,634
	CCFT TAXES:	
15	CCFT Capitalized Interest Adjustment	8
16	CCFT Tax Depreciation - Fixed Assets	2,982
17	Miscellaneous Expense Adjustments - State	(5)
18	Capitalized Overhead - Cost For Gas Inventory	(0)
19	Capitalized Software Adjustment - State	170
20	Subtotal Deductions	5,789
21	Taxable Income for CCFT	2,026
22	CCFT	179
23	State Tax Credits	(3)
24	Current CCFT	176
25	Deferred Taxes - Reg Asset	0
26	Deferred Taxes - Interest	1
27	Deferred Taxes - Vacation	(0)
28	Deferred Taxes - Fixed Assets	(12)
29	Total CCFT	164
	FEDERAL TAXES:	
30	CCFT - Prior Year Adjustment	(51)
31	FIT Capitalized Interest Adjustment	8
32	FIT Tax Depreciation - Fixed Assets	2,566
33	Miscellaneous Expense Adjustments - Federal	(8)
34	Capitalized Overhead - Cost For Gas Inventory	(0)
35	Capitalized Software Adjustment - Federal	0
36	FIT Preferred Dividend Adjustment	0
37	Subtotal Deductions	5,150
38	Taxable Income for FIT	2,665
39	Federal Income Tax	560
40	Federal Tax Credits	(10)
41	Deferred Taxes - Interest	2
42	Deferred Taxes - Vacation	(1)
43	Amortization of Excess DFIT	(130)
44	Deferred Taxes - Fixed Assets	(140)
45	Total Federal Income Tax	280

Appendix E
STIPULATION OF TURN AND PG&E ON ENERGY SUPPLY ISSUES
A.21-06-021
November 1, 2022

Introduction

The Utility Reform Network (TURN) and Pacific Gas and Electric Company (PG&E) submit the following stipulation for the purposes of resolving contested Energy Supply issues in this proceeding.

TURN and PG&E agree that this stipulation reflects a complete resolution of disputed Energy Supply issues except for attrition, depreciation and other topics not addressed in Exhibit PG&E-5. In exchange for supporting this stipulation, TURN and PG&E agree not to oppose all undisputed energy supply forecasts and energy supply proposals not specifically addressed in this stipulation (except for attrition, depreciation and other topics not addressed in Exhibit PG&E-5).

For purposes of determining final values for each of the categories, the parties agree that the final escalation amounts adopted by the Commission should apply to any identified values in the stipulation.

The stipulation reflects a compromise of disputed litigation positions on a range of Energy Supply issues addressed by the parties and constitutes an integrated agreement that should be approved in its entirety without modification. The parties request that the Commission approve the provisions of this stipulation instead of any contrary positions articulated in prepared testimony.

The Commission should find that this stipulation is reasonable in light of the testimony submitted, consistent with law, and in the public interest.

I. Nuclear Operations Costs

- A. \$9.2 million 2023 forecast reduction for a total 2023 Nuclear expense forecast of \$304.4m.
- B. No reduction in capital forecast. Any recorded capital more than PG&E's forecast would not be recorded to the Diablo Canyon Retirement Balancing Account and shall not be recoverable in rates during this GRC cycle. Parties agree to a total nuclear capital expenditure forecast of \$11.0 million, \$6.0 million, \$1.0 million, and \$0 million for 2023, 2024, 2025, and 2026, respectively.

II. Hydro Operations Costs

- A. Reduce 2023 hydro O&M by \$6.0 million (which includes \$4.7 million in 2023 for MWC IG (HLBA) for setting Large Uncontrolled Water Release (LUWR) project costs equal to 2020 RAMP forecast and \$1.3 million in 2023 for unspecified MWC(s) in response to TURN's headcount reduction recommendation for a total 2023 Hydro O&M forecast of \$171.909 million.
- B. Consistent with TURN's alternate proposal in its testimony, set 2023-2026 capital expenditure forecast for LUWR projects equal to the average between PG&E's 2020 RAMP forecast and its GRC forecast (for LUWR mitigations in RAMP for MWCs 3H, 2N, & 2L) for a total 2023-26 reduction of \$29.163 million (2023: -\$1.078 million; 2024: +\$1.238 million; 2025: -\$16.381 million; 2026: -\$12.942 million; for a total 2023-26 reduction of \$29.163 million). This reduction will be taken from MWC 3H. For purposes of the attrition mechanism (if PG&E's Exhibit 11 post-test year ratemaking proposal is adopted), the CapEx reduction would be assumed to be consistent with the capital additions reduction less forecast removal costs. Note that this stipulation does not address PG&E's Exhibit 11 post-test year ratemaking proposal. This results in a total Hydro capital expenditure forecast of \$365.209 million, \$349.381 million, \$287.512 million, and \$248.501 million for 2023, 2024, 2025, and 2026, respectively.
- C. For Hydro License Balancing Account (HLBA) capital additions with forecasted operative dates after 12/1/2026, change project operative date to 1/15/2027. This results in 2026 capital additions decrease of \$306.65 million (\$319.6 million - \$12.95 million).
- D. For HLBA capital project, "Spillway Assessment Prgm Cap Mitigation," change operative date from 12/15/21 to 1/15/24. This results in a 2023 capital addition decrease and a 2024 capital addition increase.

III. Natural Gas and Solar Generation Operations Costs

- A. No reductions to O&M expense. Parties agree to total 2023 Fossil/Solar O&M forecast of \$52.258 million.
- B. PG&E agrees with TURN's proposal to reduce Humboldt Bay Generating Station Emissions module replacement costs by 16% resulting in the following reduction: \$0.235 million, \$0.347 million, \$0.354 million, and \$0.361 million for 2023, 2024, 2025, and 2026, respectively.
- C. A 50% reduction in emergent work capex forecast in MWC 2S resulting in the following reduction: \$0 million, \$2.0 million, \$2.5 million, and \$4.1 million for 2023, 2024, 2025, and 2026, respectively.

- D. As a results of items (2) and (3) above, parties agree to a MWC 2S forecast of \$3.405 million, \$5.582 million, \$5.714 million, and \$1.735 million for 2023, 2024, 2025, and 2026, respectively, and a total Fossil/Solar capital expenditure forecast of \$6.100 million, \$6.834 million, \$6.879 million, and \$2.925 million for 2023, 2024, 2025, and 2026, respectively.
- E. Unless otherwise directed by the Commission, (1) new utility-owned generation capacity projects greater than 5 MW; or (2) new utility-owned generation capacity projects that are forecast to exceed \$20 million; or (3) utility owned generation projects that increase facility nameplate capacity by greater than 10%; or (4) utility owned generation projects that increase facility nameplate capacity that are forecast to exceed \$20 million, must be proposed in the Integrated Resource Plan proceeding or other proceeding that authorizes procurement (including, but not limited to, the Renewable Portfolio Standard Proceeding, or Resource Adequacy Proceeding or separate application), before requesting funding for the project in a GRC. This provision does not apply to reliability or efficiency projects (such as hydro turbine runner replacement or step-up transformer replacement).
- F. PG&E will implement concessions made in rebuttal testimony regarding milestone payments for Long Term Services Agreement.
- G. PG&E will implement concessions made in rebuttal testimony regarding Gateway evaporative cooling project.

IV. Energy Supply Ratemaking

- A. The Hydro License Balancing Account (HLBA) will be retained as a 2-way balancing account. If the actual combined capital and expense revenue requirements at the end of each two-year period is less than authorized, then the difference is refunded to customers. If the actual combined capital and expense revenue requirements at the end of each two-year period exceed authorized by 20% or less, then customers would be charged for the shortfall in future rates. If the actual combined capital and expense revenue requirements at the end of each two-year period exceed authorized by more than 20%, the overages would be subject to reasonableness review through a tier 3 advice letter. Any party protesting a tier 3 advice letter may request that the Commission instead consider the reasonableness of the spending in a subsequent application. If found reasonable, then customers would be charged for the shortfall in future rates. This would not be precedent setting for any other PG&E balancing accounts. A memorandum account would be used to track the overage. No change to the types of costs currently recorded to the HLBA.
- B. PG&E agrees to remove the Helms Capacity Memorandum Account (HCMA) request from the current GRC. PG&E may seek recovery of the costs associated with the

Helms Uprate Project if these costs are reasonable, the project is cost-effective, and PG&E has sought approval for the project in a CPUC proceeding.

- C. Withdrawal of proposal to include pre-2012 license condition settlement amounts in HLBA. PG&E has not included a forecast for this work in the GRC.

Appendix F

STIPULATION OF CAL ADVOCATES, TURN AND PG&E ON ENTERPRISE DATA MANAGEMENT AND INFORMATION TECHNOLOGY FORECASTS IN A.21-06-021 November 3, 2022

Introduction

The Public Advocates Office at the California Public Utilities Commission (Cal Advocates), The Utility Reform Network (TURN), and Pacific Gas and Electric Company (PG&E) submit the following stipulation for the purposes of resolving contested Enterprise Data Management (EDM) and Information Technology (IT) forecasts in this proceeding (MWC AB, MWC JV, MWC 2F). This stipulation fully resolves the forecasts in PG&E-7, Chapters 7 and 8 (Chapters 7 and 8), including those not specifically listed above. Chapters 7 and 8 addressed the following 2023 expense and capital forecasts:

<u>EXPENSE</u>			
<u>EXHIBIT</u>	<u>CHAPTER</u>	<u>MWC</u>	<u>2023 FORECAST</u>
7	8	JV	\$420,375
7	8	OM	1,406
7	8	ZC	(36,686)
7	7	AB	16,778
7	7	JV	<u>3,550</u>
Total			\$405,422

<u>CAPITAL</u>			
<u>EXHIBIT</u>	<u>CHAPTER</u>	<u>MWC</u>	<u>2023 FORECAST</u>
7	8	2F	\$265,900
7	7	2F	<u>2,000</u>
Total			\$267,900

Cal Advocates, TURN and PG&E agree that this stipulation reflects a complete resolution of disputed EDM and IT issues except for attrition, depreciation and other topics not addressed in Chapters 7 and 8. Cal Advocates, TURN and PG&E agree not to oppose all undisputed forecasts and proposals in Chapters 7 and 8 not specifically addressed in this stipulation.

For purposes of determining final values for each of the categories, the parties agree that the final escalation factors adopted by the Commission should apply, where appropriate, to any identified values in the stipulation.

The stipulation reflects a compromise of disputed litigation positions on a range of EDM and IT issues addressed by the parties and constitutes an integrated agreement that should be approved in its entirety without modification. The parties request that the Commission approve the provisions of this stipulation instead of any contrary positions articulated in prepared testimony.

The Commission should find that this stipulation is just and reasonable in light of the testimony submitted, consistent with law, and in the public interest.

I. Enterprise Data Management Costs (Chapter 7)

The parties' litigation positions as to contested forecasts were as follows:

- A. PG&E's 2023 expense forecast for Enterprise Records and Information Management and EDM was \$20.328 million, which included \$3.8 million for the EDM program (MWC AB).
- B. Cal Advocates opposed all of PG&E's 2023 expense forecast of \$3.8 million for EDM.

The parties agree that the following forecasts are a reasonable compromise of the parties' litigation positions and should be approved:

- C. PG&E's forecast of \$3.8 million in 2023 for EDM (MWC AB) should be approved in full.

II. Information Technology Costs (Chapter 8)

The parties' litigation positions as to contested forecasts were as follows:

- A. PG&E's 2023 expense forecast for IT was \$385.094, which included \$420.375 for Baseline Operations and Management and Technology Investments in Solution Delivery and Operations, Fieldwork Management, Data Enablement, and Enterprise Resource Management Expense (MWC JV).
- B. PG&E's 2023 capital forecast for IT was \$265.9 million, which included Technology Investments Portfolio Core Network Infrastructure and Operations Capital (MWC 2F).
- C. Cal Advocates recommended a total reduction of \$80.947 million to PG&E's 2023 expense forecast for Baseline Operations and Management and Technology Investments in Solution Delivery and Operations, Fieldwork Management, Data Enablement, and Enterprise Resource Management Expense (MWC JV).
- D. Cal Advocates recommended a total reduction of \$58.9 million to PG&E's 2023 capital forecast for Technology Investments Portfolio Capital (MWC 2F).
- E. TURN recommended a total reduction of \$35.5 million to PG&E's 2023 expense forecast for Baseline Operations and Management Expense (MWC JV).

- F. TURN recommended a total reduction of \$54.935 to PG&E's 2023 capital forecast for Technology Investments Portfolio Core Network Infrastructure and Operations Capital (MWC 2F).

The parties agree that the following forecasts are a reasonable compromise of the parties' litigation positions and should be approved:

- G. O&M for Baseline Operations and Management and Technology Investments in Solution Delivery and Operations, Fieldwork Management, Data Enablement, and Enterprise Resource Management Expense (MWC JV): approve a total 2023 expense forecast of \$378.375 million, a reduction of \$42 million to PG&E's initial request.
- H. Technology Investments Portfolio, including Core Network Infrastructure and Operations, Capital (MWC 2F): Approve a total 2023 capital forecast of \$259.9 million, a reduction of \$6 million to PG&E's initial request.

APPENDIX G
STIPULATION OF TURN, CAL ADVOCATES AND PG&E ON ADMINISTRATIVE AND
GENERAL ISSUES
A.21-06-021
November 1, 2022

Introduction

The Utility Reform Network (TURN), the Public Advocates Office at the California Public Utilities Commission (Cal Advocates) and Pacific Gas and Electric Company (PG&E) (collectively referred to as the Parties) submit the following stipulation for the purposes of resolving all contested Administrative and General (A&G) issues in this proceeding.

The Parties agree that this stipulation reflects a complete resolution of disputed A&G issues except for Wildfire Liability Insurance, which has been resolved through a settlement agreement.¹ In exchange for supporting this stipulation, TURN, Cal Advocates and PG&E agree not to oppose all undisputed A&G forecasts and proposals not specifically addressed in this stipulation.

For purposes of determining final values for each of the categories, the parties agree that the final escalation amounts adopted by the Commission should apply to any identified values in the stipulation.

The stipulation represents an agreement on revenue requirements only and is not intended to address or resolve issues of Commission policy with respect to the costs at issue in this exhibit.

The stipulation reflects a compromise of disputed litigation positions on a range of A&G issues addressed by the Parties and constitutes an integrated agreement that should be approved in its entirety without modification. The parties request that the Commission approve the provisions of this stipulation instead of any contrary positions articulated in prepared testimony.

The Commission should find that this stipulation is reasonable in light of the testimony submitted, consistent with law, and in the public interest.

Stipulations

I. Finance: Bank Fees – Letters of Credit

- A. PG&E forecasted \$1.75 million for Letter of Credit (LOC fees). TURN recommended a reduction of \$1.5 million to the LOC fees associated with the sale of the General Office complex for a forecast of \$0.250 million.
- B. The parties agree upon a 2023 expense forecast of \$0.250 million.

¹ Wildfire Liability Insurance has been addressed in the *Joint Motion of Pacific Gas and Electric Company, The Utility Reform Network and The Public Advocates Office at the California Public Utilities Commission for Expedited Approval and Adoption of the Attached Settlement Agreement on Insurance Related Issues* (Joint Motion for Adoption of Insurance Settlement) (October 7, 2022).

II. Risk, Audit, and Insurance Department Costs: Internal Audit Program Manager and Privileged Internal Audits

- A. PG&E forecasted \$13.22 million for Risk, Audit and Insurance department costs.
- B. Cal Advocates recommended a \$0.159 million reduction to remove the cost of filling one of the vacancies for Project Manager, Principal.
- C. Cal Advocates also recommended a \$0.136 million reduction to PG&E's 2023 forecast associated with the cost of performing a privileged audit in 2020 that PG&E withheld from production subject to the attorney client privilege.
- D. The parties agree on a 2023 forecast of \$13.06 million.

III. Risk, Audit, and Insurance: Remaining Insurance Forecasts Aside From Wildfire Liability Insurance

- A. For its remaining insurance items (aside from wildfire liability insurance, which is addressed in a settlement), PG&E forecasted a total \$199.575 million. This forecast amount is the total of the individual forecasts for Non-Wildfire Liability, D&O, Other Liability, Nuclear Property, Non-Nuclear Property, Other Property, and the PG&E Corporate Allocation.
- B. Neither Cal Advocates nor TURN opposed PG&E's forecasts for these insurance items.
- C. The 2023 forecast will be \$199.575 million in expense.

IV. Risk, Audit, and Insurance: Risk Transfer Balancing Account (RTBA) for Non-Wildfire Liability Insurance Costs

- A. Of the \$199.575 million expense forecast discussed in Section IV, \$156 million is for non-wildfire liability insurance. PG&E proposed that the \$156 million forecast for non-wildfire liability insurance should be subject to 2-way balancing account treatment through the RTBA.
- B. Neither Cal Advocates nor TURN opposed PG&E's forecast for non-wildfire liability insurance, but TURN opposed PG&E's ratemaking proposal for non-wildfire liability insurance costs to be recorded in the RTBA.
- C. For non-wildfire liability insurance, the 2023 forecast will be \$156 million. PG&E will track in the RTBA costs incurred to procure coverage up to the \$700 million coverage target. If annual incurred costs are less than PG&E's forecast of \$156 million, PG&E will return to ratepayers in the next annual RTBA true-up the difference between the amount collected and amount

incurred. If annual incurred costs are above the forecast amount, PG&E is permitted to seek recovery of such costs by application.

V. Law: Litigation Settlement and Judgments and Claims Forecast

- A. PG&E's 2023 forecast is \$36.376 million.
- B. Cal Advocates recommended a total forecast of \$31.44 million.
- C. The parties agree upon a 2023 expense forecast of \$33.9 million.

VI. PG&E Corporation & PG&E Executive Offices and Corporate Secretary: Board of Directors Fees

- A. PG&E forecasts \$2.44 million for PG&E Corporation's Director fees and expenses. TURN recommends \$1.22 million.
- B. The parties agree upon a 2023 expense forecast of \$1.83 million.

Appendix H

Test-Year 2023 Forecast Summaries

The tables below show PG&E’s test-year 2023 expense and capital forecast and amounts remaining at issue.

- Table 1 – PG&E’s 2023 revenue requirement
- Table 2 – PG&E’s 2023 final expense forecast by exhibit and 2023 final expense forecast by exhibit including the September 6, 2022 escalation adjustment.
- Table 3 – PG&E’s 2023 final capital forecast by exhibit and 2023 final capital forecast by exhibit including the September 6, 2022 escalation adjustment.
- Table 4 – PG&E’s 2023 final expense forecast, uncontested amounts, and amounts remaining at issue.
- Table 5 – PG&E’s 2023 final capital forecast uncontested amounts, and amounts remaining at issue.
- Table 6 – PG&E’s 2023 final department cost forecast, uncontested amounts, and amounts remaining at issue.
- Table 7 - PG&E’s 2023 final companywide expense forecast uncontested amounts, settled amounts, and amounts remaining at issue.

Table 1 – PG&E’s Forecast Revenue Requirement^(a) (Millions of Nominal Dollars)			
Description	2022 Authorized Revenue	2023 GRC Forecast	2023 Increase Over 2022
PG&E’s Amended Application	\$12,214	\$15,339	\$3,125
Escalation Update		\$801	\$801
Federal Tax Update		\$35	\$35
PG&E’s Sept. 2022 Update Testimony		\$16,175	\$3,961
Rebuttal Errata and Concessions		\$27	\$27
Hydro Decommissioning Stipulation		\$(20)	\$(20)
Total Revenue Requirement	\$12,214	\$16,181	\$3,967
(a) PG&E-64, p. 1-2, Table 1-1			

Table 2 - Test-Year 2023 Expense Forecasts (Thousands of Nominal Dollars)			
Exhibit	Final Forecast^(a)	Updated Final Forecast^(b)	Difference
Gas Operations	\$1,212,412	\$1,316,806	\$104,394
Electric Distribution	\$2,209,632	\$2,597,136	\$387,504
Energy Supply	\$590,393	\$633,475	\$43,082
Customer and Communications	\$373,619	\$386,680	\$13,061
Shared Services and Information Technology	\$744,036	\$790,110	\$46,074
Human Resources	\$288	\$300	\$12
Administrative and General	\$1,540	\$1,594	\$54
Total	\$5,131,921	\$5,726,101	\$594,180
(a) Final forecast includes PG&E's February 28, 2022 forecast plus errata and concessions. <i>See</i> PG&E-64, the Amended Joint Comparison Exhibit (JCE), Chapter 3, Table 3A-1 and Table 3C-1, Column "PG&E (without Sep 6 Capital Escalation Adjustment)." (b) Updated Final Forecast represents PG&E's final forecast plus the September 6, 2022 escalation update. <i>See</i> PG&E-64, Chapter 3, Table 3A-1 and Table 3C-1, Column "PG&E (with Sep 6 Capital Escalation Adjustment)."			

Table 3 - Test-Year 2023 Capital Forecasts (Thousands of Nominal Dollars)			
Exhibit	Final Forecast^(a)	Updated Final Forecast^(b)	Difference
Gas Operations	\$2,282,565	\$2,705,212	\$422,647
Electric Distribution	\$4,517,671	\$5,117,678	\$600,007
Energy Supply	\$397,721	\$463,095	\$65,374
Customer and Communications	\$286,567	\$338,811	\$52,244
Shared Services and Information Technology	\$1,473,117	\$1,595,232	\$122,115
Human Resources	\$1,000	\$1,210	\$210
Administrative and General	\$2,500	\$3,025	\$525
Total	\$8,961,141	\$10,224,263	\$1,263,122
(a) PG&E-64, Exhibit Chapter 3, Table 3B-1. Column "PG&E (without Sep 6 Capital Escalation Adjustment)." (b) PG&E-64, Chapter 3, Table 3B-1. Column "PG&E (with Sep 6 Capital Escalation Adjustment)."			

Table 4 - Test-Year 2023 Expense Forecasts Amounts Remaining at Issue (Thousands of Nominal Dollars)			
Exhibit	Final Forecast^(a)	Uncontested Amounts^(b)	Amounts Remaining at Issue^(c)
Gas Operations	\$1,212,412	\$524,364	\$688,048
Electric Distribution	\$2,209,632	\$781,758	\$1,427,874
Energy Supply ^(d)	\$590,393	\$98,507	\$491,886
Customer and Communications	\$373,619	\$225,040	\$148,579
Shared Services and Information Technology ^(e)	\$744,036	\$133,159	\$610,877
Human Resources	\$288	\$288	\$0
Administrative and General ^(f)	\$1,540	\$1,540	\$0
Total ^(g)	\$5,131,921	\$1,764,656	\$3,367,265
(a) PG&E-64, Chapter 3, Table 3A-1 and Table 3C-1, Column “PG&E (without Sep 6 Non-Labor Escalation Adjustment). (b) Includes forecast items that parties did not dispute. The individual items are listed in Appendix A. (c) Amounts shown in this table do not include PG&E’s September 6, 2022 inflation escalation adjustment. (d) Does not reflect the agreement reached between PG&E and TURN have reached reflecting a complete resolution of disputed Energy Supply issues between PG&E and TURN included in Appendix E. (e) Does not reflect the settlement proposal on disputed issues in Exhibit F. (f) Does not reflect the settlement proposal on disputed issues in Exhibit G. (g) Does not reflect settlement proposals Appendix E, F and G.			

Table 5 - Test-Year 2023 Capital Forecasts Amounts Remaining at Issue (Thousands of Nominal Dollars)			
Exhibit	Final Forecast^(a)	Uncontested Amounts^(b)	Amounts Remaining at Issue^(c)
Gas Operations	\$2,282,565	\$751,424	\$1,531,141
Electric Distribution	\$4,517,671	\$627,957	\$3,889,714
Energy Supply ^(d)	\$397,721	\$18,657	\$379,064
Customer and Communications	\$286,567	\$200	\$286,367
Shared Services and Information Technology	\$1,473,117	\$94,292	\$1,378,825
Human Resources	\$1,000	\$1,000	\$0
Administrative and General	\$2,500	\$2,500	\$0
Total ^(g)	\$8,961,141	\$1,496,030	\$7,465,111
(a) PG&E-64, Chapter 3, Table 3B-1, Column “PG&E (without Sep 6 Capital Escalation Adjustment). (b) Includes forecast items that parties did not dispute. The individual items are listed in Appendix A. (c) Amounts shown in this table do not include PG&E’s September 6, 2022 inflation escalation adjustment. (d) Does not reflect the agreement reached between PG&E and TURN reflecting a complete resolution of disputed Energy Supply issues between PG&E and TURN included in Appendix E. (e) Does not reflect the settlement proposal on disputed issues in Exhibit F. (f) Does not reflect the settlement proposal on disputed issues in Exhibit G. (g) Does not reflect settlement proposals in Appendix E, F and G.			

Table 6 - Test-Year 2023 Department Cost Forecasts: Amounts Remaining at Issue (Thousands of Nominal Dollars)			
Exhibit	Final Forecast^(a)	Uncontested Amounts^(b)	Amounts Remaining at Issue^(c)
Human Resources	\$85,386	\$0	\$85,386
Administrative and General (PG&E-9, Ch.2-8) ^(d)	\$153,892	\$140,671	\$13,221
Total ^(d)	\$239,278	\$140,671	\$98,607
(a) PG&E-64, Chapter 3, Table 3B-1, Column “PG&E (without Sep 6 Capital Escalation Adjustment). (b) Includes forecast items that parties did not dispute. The individual items are listed in Appendix A. (c) Amounts shown in this table do not include PG&E’s September 6, 2022 inflation escalation adjustment. (d) Does not reflect the settlement proposal on disputed issues in Exhibit G.			

Table 7 - Test-Year 2023 Companywide Expense Cost Forecasts Amounts Remaining at Issue (Thousands of Nominal Dollars)				
Exhibit	Final Forecast^(a)	Uncontested Amounts^(b)	Settled Amounts^(c)	Amounts Remaining at Issue^(d)
Shared Services and Information Technology (PG&E-7, Ch. 1A)	\$154,509	\$3,595	N/A	\$150,914
Human Resources – Expense Costs (PG&E-8, Ch. 3-5)	\$985,869	\$8,888	N/A	\$976,981
Human Resources – Employee Contributions (PG&E-8, Ch. 3-5)	\$(41,375)	\$(32,487)	N/A	\$(8,888)
Administrative and General (PG&E- 9, Ch. 3-7) ^(e)	\$955,516	\$208,255	\$307,000	\$440,291
Total ^(e)	\$2,054,519	\$179,363	\$307,000	\$1,426,007
(a) PG&E-64, Chapter 3, Table 3C-1, Column “PG&E (without Sep 6 Non-Labor Escalation Adjustment). (b) Includes forecast items that parties did not dispute. The individual items are listed in Appendix A. (c) Includes settled items as of October 31, 2022. (d) Amounts shown in this table do not include PG&E’s September 6, 2022 inflation escalation adjustment. (e) Does not reflect the settlement proposal on disputed issues in Exhibit G.				