Application: 21-06-021
(U 39 M)
Exhibit No.: (PG&E-23)
Date: July 11, 2022
Witness(es): Various

PACIFIC GAS AND ELECTRIC COMPANY

2023 GENERAL RATE CASE

REBUTTAL TESTIMONY

EXHIBIT (PG&E-23)

RESULTS OF OPERATIONS

PACIFIC GAS AND ELECTRIC COMPANY
2023 GENERAL RATE CASE
EXHIBIT (PG&E-23)
RESULTS OF OPERATIONS

TABLE OF CONTENTS

PACIFIC GAS AND ELECTRIC COMPANY
2023 GENERAL RATE CASE
EXHIBIT (PG&E-23)
RESULTS OF OPERATIONS

TABLE OF CONTENTS
(CONTINUED)

PACIFIC GAS AND ELECTRIC COMPANY

CHAPTER 1

INTRODUCTION

THIS CHAPTER HAS NO REBUTTAL

PACIFIC GAS AND ELECTRIC COMPANY

CHAPTER 1A

COST ALLOCATION

THIS CHAPTER HAS NO REBUTTAL

PACIFIC GAS AND ELECTRIC COMPANY

CHAPTER 2

SAP FERC TRANSLATION

THIS CHAPTER HAS NO REBUTTAL

PACIFIC GAS AND ELECTRIC COMPANY

CHAPTER 3

ELECTRIC DISTRIBUTION O&M EXPENSE

THIS CHAPTER HAS NO REBUTTAL

PACIFIC GAS AND ELECTRIC COMPANY

CHAPTER 4

GAS DISTRIBUTION O&M EXPENSE

THIS CHAPTER HAS NO REBUTTAL

PACIFIC GAS AND ELECTRIC COMPANY

CHAPTER 5

CUSTOMER ACCOUNTS EXPENSE

THIS CHAPTER HAS NO REBUTTAL

PACIFIC GAS AND ELECTRIC COMPANY

CHAPTER 6

GENERATION O&M EXPENSE

THIS CHAPTER HAS NO REBUTTAL

PACIFIC GAS AND ELECTRIC COMPANY

CHAPTER 7

GAS TRANSMISSION AND STORAGE O&M EXPENSE

THIS CHAPTER HAS NO REBUTTAL

PACIFIC GAS AND ELECTRIC COMPANY

CHAPTER 8

ERRATA TESTIMONY OF

IVANA E. TAMBURRINO

ADMINISTRATIVE AND GENERAL EXPENSES

PACIFIC GAS AND ELECTRIC COMPANY
CHAPTER 8
ERRATA TESTIMONY OF
IVANA E. TAMBURRINO
ADMINISTRATIVE AND GENERAL EXPENSES

TABLE OF CONTENTS

PACIFIC GAS AND ELECTRIC COMPANY
CHAPTER 8
ERRATA TESTIMONY OF
IVANA E. TAMBURRINO
ADMINISTRATIVE AND GENERAL EXPENSES

A. Introduction

Q 1 Please state your name and the purpose of this rebuttal testimony.

A 1 My name is Ivana Emilia Tamburrino. This testimony summarizes errata for the Results of Operation Exhibit (RO) (PG&E-10) Administrative and General (A&G) Expenses Chapter 8 testimony served February 28, 2022.

PG&E's response to the direct testimony of Public Advocates Office at the California Public Utilities Commission (Cal Advocates or CA)[1] and The Utility Reform Network (TURN)[2] concerning recommended adjustments to Department Costs, Companywide Expenses, and Information Technology (IT) Projects is included in the individual rebuttal chapters supporting the exhibits.[3]

B. Summary of Errata Items

Q 2 Does PG&E have any adjustments or corrections to its forecasts as provided in its February 28, 2022 testimony?

A 2 Yes. PG&E corrects its Test Year (TY) 2023 and Post Test Years (PTYs) 2024-2026 revenue requirements to allocate 100 percent of wildfire liability self-insurance costs to the Electric Distribution (ED) function as described in its opening testimony. In Exhibit (PG&E-10), PG&E inadvertently allocated a portion of self-insurance costs to the Network Transmission (NWT) under the Federal Regulatory Energy Commission (FERC) jurisdiction.[4]

---

1 CA-11, CA-12 and CA-13.

2 TURN-05 and TURN-17.

3 Department expenses in Exhibits Human Resources (PG&E-21) and Corporate Services Organizations (PG&E-22); Companywide expenses in Exhibits Shared Services and Information Technology (PG&E-20), Human Resources (PG&E-21) and Corporate Services Organizations (PG&E-22); and Information Technology expenses in Exhibit Shared Services and Information Technology (PG&E-20).

4 Exhibit (PG&E-10) (Feb. 28, 2022), Ch. 8.

Q 3 How is PG&E proposing wildfire liability self-insurance costs be allocated to its business functions?

A 3 In the 2023 GRC Exhibit (PG&E-9) Chapter 3 testimony, PG&E describes two proposals for the use of self-insurance in PG&E's insurance program for 2023 and beyond. Specifically, PG&E proposes to designate a portion of revenue requirements for wildfire liability insurance to self-insurance. As described in Exhibit (PG&E-9) Chapter 3 testimony, the proposed TY 2023 self-insurance amount is $250 million, and the proposed 2024-2026 self-insurance amount is $325 million ($250 million + $75 million) per year.[5]

For both alternatives, PG&E proposes that self-insurance be funded exclusively through the CPUC-jurisdictional retail rates for the 2023 GRC period. There is currently a settlement in place with respect to the FERC formula rate to recover Electric Network Transmission costs for PG&E through the end of 2023. PG&E will request cost recovery for self-insurance through the FERC process within the course of the GRC period for 2024 and beyond. To the extent PG&E obtains cost recovery from FERC jurisdictional customers, the amount approved by FERC will be credited back to CPUC rates through a credit to the Risk Transfer Balancing Account (RTBA).[6] Consistent with the self-insurance proposals described in Exhibit (PG&E-9) Chapter 3 testimony, PG&E should have allocated 100 percent of the self-insurance revenue requirements to the ED function in the TY 2023 and the PTYs 2024-2026. Instead, in all four years 2023-2026 PG&E inadvertently allocated a portion of self-insurance costs to NWT FERC-jurisdictional customers in the Results of Operations Model using the wildfire insurance allocation factors shown on Table 8-5 of Exhibit (PG&E-10), Chapter 8 testimony.

---

5 PG&E sets a target of $1 billion in self-insurance for wildfire claims in accordance with the Assembly Bill 1054 eligibility requirements for the Wildfire Fund. The risk to customers is minimized by capping the total amount of customer-funded self-insurance to $1 billion.

6 More information about the two self-insurance proposals and the RTBA is provided in Exhibit (PG&E-9) (Feb. 28, 2022), Ch. 3.

Q 4 Does this self-insurance allocation Errata result in a revenue requirement error?

A 4 Yes. The GRC TY 2023 revenue requirement is understated by approximately $42 million, and the PTY 2024-2026 revenue requirements are understated by approximately $92 million per year (plus an allowance for Revenue Fees and Uncollectible [RF&U]). The revenue requirement understatement amounts are calculated as follows:

- TY 2023.

  $250 million self-insurance X 16.73%[7] 2023 NWT wildfire allocation factor = $42 million.

- PTYs 2024-2026.

  $325 million self-insurance X 28.16%[8] 2024-2026 NWT wildfire allocation factor = $92 million

Q 5 Will PG&E incorporate a revenue requirement correction for self-insurance costs in its upcoming GRC revenue requirement update?

A 5 Yes. In the upcoming Joint Comparison Exhibit (JCE), PG&E will update its TY 2023 and PTYs 2024-2026 revenue requirements to allocate 100 percent of self-insurance costs to ED rates. This correction will increase TY 2023 revenue requirements by approximately $42 million and 2024-2026 revenue requirements by approximately $92 million per year, plus an allowance for RF&U.

Refer to:

- Table 8-1 below for a description of the Administrative and General (A&G) costs allocation methods by cost type. Line 3 of this table is updated to include the allocation of wildfire liability self-insurance costs as 100% to ED in the TY 2023 and PTYs 2024-2026.
- Table 8-2 which adds a note to the wildfire liability insurance allocation factors table to clarify that 100% of wildfire liability self-insurance costs are allocated to ED.

PG&E also submits updated Exhibit (PG&E-10) Chapter 8 workpaper page 8-16 to add a note to the wildfire liability insurance costs allocation

7 Exhibit (PG&E-10) (Feb. 28, 2022), p. 8-11, Table 8-5, line 1.

8 Exhibit (PG&E-10) (Feb. 28, 2022), p. 8-11, Table 8-5, line 2.

factors table to clarify that 100% of wildfire liability self-insurance costs are allocated to ED.

Q 6 Does PG&E have any non-forecast related adjustments or corrections to the February 28, 2022 testimony and/or workpapers?

A 6 Yes. PG&E describes non-forecast adjustments below. These adjustments are also summarized on Table 8-8 at the end of this chapter.

1) PG&E corrects Exhibit (PG&E-10) Chapter 8 testimony allocation Table 8-4 End of Year (EOY) Plant Allocation Factors and Table 8-6 Blended Labor and Plant Allocation Factors to remove Gas Transmission (GT) Excess Line 401 costs from the GRC allocation factor. A&G are typically common costs that are allocated to the business functions using common cost allocation factors. When developing the 2023 GRC period EOY Plant and Blended Labor and Plant factors, PG&E inadvertently included in the GT factor EOY plant costs associated with GT Excess Line 401. These costs should be excluded because GT Excess Line 401 costs are not recovered in the GRC. PG&E provides corrected allocation Tables for EOY Plant and Blended Labor and Plant factors in Table 8-3 and Table 8-4, respectively. PG&E also submits updated Exhibit (PG&E-10) Chapter 8 workpaper pages 8-14 and 8-15 to correct the EOY Plant and Blended Labor and Plant Allocation factors tables, respectively, to remove GT Excess Line 401 costs.

2) PG&E corrects Exhibit (PG&E-10) Chapter 8 testimony Table 8-8 TY 2023 Forecast A&G Costs by business function, Table 8-9 Recorded Adjusted Year 2020 A&G Costs, and Table 8-10 Difference from Recorded Adjusted Year 2020 to TY 2023 A&G Costs for the allocation of wildfire liability insurance costs. All wildfire liability insurance costs on these tables, including self-insurance, were inadvertently allocated to the ED and NWT using 2024-2026 wildfire insurance allocation factors, which have an ED factor of 71.84 percent.[9] To correct the revenue requirements shown by business function on these tables, PG&E first allocated 100 percent of TY 2023 wildfire liability self-insurance to ED,

[9] Exhibit (PG&E-10) (Feb. 28, 2022), p. 8-11, Table 8-5, line 2.

and then allocated the remaining wildfire liability insurance costs to the ED and NWT using the TY 2023 wildfire allocation factors, which have a higher ED factor of 83.23 percent.[10] Refer to the following corrected tables:

- Table 8-5 Total GRC Forecast for 2023;
- Table 8-6 2020 Recorded Adjusted GRC A&G Expense; and
- Table 8-7 Difference from 2020 Recorded Adjusted to 2023 Forecast A&G Expense.

Note, the corrected Table 8-4 shows an approximately $87 million increase in TY 2023 revenue requirements allocated to ED. Approximately $42 million of the increase is related to allocating 100 percent of self-insurance to ED and the remaining $44.7 million increase is related to using the TY 2023 wildfire insurance allocation factors. The $87 million is different than the $42 million revenue requirement increase described in the response to Q5 above because the tables in this section correct for both the allocation of all wildfire liability self-insurance to ED and the wildfire allocation factors from PTY to TY factors.

Q 7 Do the non-forecast adjustments or corrections result in a revenue requirement error?

A 7 No. In this section PG&E is describing only the presentation of costs included in Exhibit (PG&E-10) Chapter 8 testimony and workpaper tables. The errata of $42 million revenue requirement for TY 2023 and $92 million revenue requirement for PTYs 2024-2026 is described in the responses to Q4 and Q5 above.

Q 8 Does this conclude your rebuttal testimony?

A 8 Yes, it does.

[10] Exhibit (PG&E-10) (Feb. 28, 2022), p. 8-11, Table 8-5, line 2.

TABLE 8-1
ALLOCATION METHODOLOGIES

Line No.	Cost Type	Test Year 2023	Post Test Years 2024-2026	Exhibit (PG&E-10) Ch. 8 Table Reference
1	Nuclear Liability and Nuclear Property Insurance	Allocate 100 percent to nuclear generation UCCs. Note: Year 2026 costs will be included in the separate NDCTP proceeding.		n/a
2	Non-Nuclear Property Insurance	Allocate to all UCCs using EOY plant factors.		8-4
3	Wildfire Liability Insurance	Allocate 100 precent wildfire liability self-insurance to electric distribution. Allocate other wildfire liability insurance to NWT using TO FERC approved blended 60 percent labor/40 percent EOY plant factors with the remaining costs allocated to electric distribution.	Allocate 100 percent wildfire liability self-insurance to electric distribution. Allocate other wildfire liability insurance to electric distribution and NWT using EOY plant factors.	8-5
4	Non-Wildfire Liability Insurance, Third-Party Claims and Litigation Settlements and Judgements	Allocate to electric distribution and NWT using blended 60 percent labor/40 percent EOY plant factors.	Allocate to electric distribution and NWT using blended 50 percent labor/50 percent EOY plant factors.	8-6
5	All Other A&G Cost Types	Continue to allocate to all UCCs using the labor factors.		8-7

Note: Table 8-1 shown above corrects the wildfire liability insurance line 3 of Table 8-3 in Exhibit (PG&E-10) Ch. 8 testimony.

TABLE 8-2[C]
BLENDED LABOR AND PLANT ALLOCATION FACTORS FOR ELECTRIC DISTRIBUTION AND TRANSMISSION UCCS

Line No.	UCC	Year 2023 Wildfire Liability Insurance uses the TO FERC approved Blended Labor Factor %	Years 2024-2026 Wildfire Liability Insurance uses the 100% Plant factor for all LOBs %
1	ET – Network Transmission [a]	16.77%	28.16%
2	Electric Distribution [b]	83.23%	71.84%
3	Total	100.00%	100.00%

(a) TO Rate Year 2022 draft annual update submitted at FERC on June 15, 2021.

(b) 100% of wildfire liability self-insurance costs are allocated to ED; the remaining wildfire liability insurance costs are allocated to NWT and ED using the allocation factors shown in the table above.

(c) Table 8-2 shown above adds note (b) to Table 8-5 in Exhibit (PG&E-10) Ch. 8 testimony.

TABLE 8-3[a],[b]
EOY PLANT ALLOCATION FACTORS FOR ALL UCCS

Line No.	UCCs	Years 2020-2023 Property Insurance uses the 100% Plant factor for all LOBs %	Year 2024 Property Insurance uses the 100% Plant factor for all LOBs %	Year 2025 Property Insurance uses the 100% Plant factor for all LOBs %	Year 2026 Property Insurance uses the 100% Plant factor for all LOBs %
1	EG – Power Generation – GRC	18.53%	18.53%	13.96%	8.85%
2	Electric Distribution	40.33%	40.33%	42.59%	45.12%
3	Gas Transmission (GT) – GT&S	9.49%	9.49%	10.02%	10.62%
4	Gas Distribution	15.64%	15.64%	16.52%	17.50%
5	Total GRC	83.99%	83.99%	83.09%	82.09%
6	ET – Network Transmission	15.81%	15.81%	16.69%	17.69%
7	Other – Electric and Gas Transmission	0.20%	0.20%	0.21%	0.23%
8	Total Non-GRC	16.01%	16.01%	16.91%	17.91%
9	Total Company	100.00%	100.00%	100.00%	100.00%

(a) Table 8-3 shown above corrects the GT&S, Total GRC, Other and Total Non-GRC lines, 3, 5, 7 and 8 of Table 8-4, respectively, in Exhibit (PG&E-10) Ch. 8 testimony.

(b) There may be immaterial differences due to rounding.

TABLE 8-4[a]
BLENDED LABOR AND PLANT ALLOCATION FACTORS FOR ALL UCCS

Line	UCC	Years 2020 - 2023			Year 2024			Year 2025			Year 2026		
		60%	40%		50%	50%		50%			50%	50%	
		Recorded 2020 Labor	Recorded 2020 Plant	2020 Network Transmission factor per 60% labor/40% plant	Recorded 2020 Labor	Recorded 2020 Plant	2020 Network Transmission factor per 50% labor/50% plant	Recorded 2020 Labor Nuclear Divided by 2	Recorded 2020 Plant Nuclear Divided by 2	2020 Allocation factor (50% labor/50% plant)	Recorded 2020 Labor Nuclear Removed	Recorded 2020 Plant Nuclear Removed	2020 Allocation factor (50% labor/50% plant)
		%	%	%	%	%	%	%	%	%	%	%	%
1	EG - Power Generation - GRC	21.40%	18.53%	20.25%	21.40%	18.53%	19.96%	15.50%	13.96%	14.73%	8.65%	8.85%	8.75%
2	ED - Electric Distribution	38.77%	40.33%	39.39%	38.77%	40.33%	39.55%	41.68%	42.59%	42.13%	45.06%	45.12%	45.09%
3	GT - Gas Transmission and Storage	9.76%	9.49%	9.65%	9.76%	9.49%	9.63%	10.50%	10.02%	10.26%	11.35%	10.62%	10.98%
4	GD - Gas Distribution	20.48%	15.64%	18.55%	20.48%	15.64%	18.06%	22.02%	16.52%	19.27%	23.81%	17.50%	20.65%
5	**Total GRC**	90.42%	83.99%	87.85%	90.42%	83.99%	87.20%	89.70%	83.09%	86.39%	88.86%	82.09%	85.47%
6													
7	ET - Network Transmission	9.51%	15.81%	12.03%	9.51%	15.81%	12.66%	10.23%	16.69%	13.46%	11.05%	17.69%	14.37%
8	ET & GT - Other Transmission	0.07%	0.20%	0.12%	0.07%	0.20%	0.14%	0.08%	0.21%	0.15%	0.08%	0.23%	0.16%
9	**Total Non-GRC**	9.58%	16.01%	12.15%	9.58%	16.01%	12.80%	10.30%	16.91%	13.61%	11.14%	17.91%	14.53%
10													
11	**Total Company**	100.00%	100.00%	100.00%	100.00%	100.00%	100.00%	100.00%	100.00%	100.00%	100.00%	100.00%	100.00%

(a) Table 8-4 shown above corrects the GT&S, Total GRC, Other Transmission and Total Non-GRC lines, 3, 5, 8 and 9 of Table 8-6, respectively, in Exhibit (PG&E-10) Ch. 8 testimony.

TABLE 8-5(d)
TOTAL GRC FORECAST FOR 2023(a),(b),(g)
(THOUSANDS OF NOMINAL DOLLARS)

Line No.	FERC Account	Description	Total Company(b),(c)	Total Non-GRC	Total GRC	EG	Electric Distribution	Gas Distribution	GT
1	920	Administrative and General Salaries	$601,646	$57,655	$543,991	$128,740	$233,268	$123,244	$58,740
2	921	Office Supplies and Expenses	113,041	10,833	102,208	24,188	43,828	23,156	11,036
3	922	A&G Capital Transfer	(100,223)	(9,604)	(90,619)	(21,446)	(38,858)	(20,530)	(9,785)
4	923	Outside Services	390,206	37,421	352,785	83,420	151,446	79,858	38,062
5	924	Property Insurance	28,632	4,567	24,065	5,394	11,502	4,461	2,707
6	925	Injuries and Damages (e),(f)	959,496	105,735	853,762	53,047	729,041	47,457	24,217
7	926	Pension and Benefits (a)	797,702	76,443	721,259	170,691	309,282	163,405	77,881
8	928	Regulatory Commission Expense	–	–	–	–	–	–	–
9	930	Miscellaneous General Expenses	10,749	1,030	9,719	2,300	4,168	2,202	1,049
10	935	Maintenance of General Plant	–	–	–	–	–	–	–
11		Total A&G Expenses	$2,801,250	$284,079	$2,517,170	$446,334	$1,443,676	$423,252	$203,908

(a) 2023 Forecast does not include pension contribution.
(b) Total Company A&G costs for the forecast year 2023.
(c) Excluding Franchise Fees.
(d) Table 8-5 shown above corrects the Electric Distribution, Total GRC and Total Non GRC Columns of Table 8-8 in Exhibit (PG&E-10) Ch. 8 testimony.
(e) The Electric Distribution LOB is corrected to include 100% of the TY 2023 forecasted $250 million in wildfire liability self-insurance costs.
(f) The allocation of wildfire liability insurance excluding self-insurance is corrected to use TY 2023 wildfire liability insurance allocation factors.
(g) A correction is not needed for the GT Excess Line 401 item described in the response to Q6 (1) above because the error is not reflected in Tables 8-8, 8-9 and 8-10 from Exhibit (PG&E 10) Ch. 8 testimony.

TABLE 8-6[c]
2020 RECORDED ADJUSTED GRC A&G EXPENSE[a],[e]
(THOUSANDS OF NOMINAL DOLLARS)

Line No.	FERC Account	Description	Total Company[b]	Total Non-GRC	Total GRC	EG	Electric Distribution	Gas Distribution	GT
1	920	Administrative and General Salaries	$447,757	$42,908	$404,849	$95,810	$173,602	$91,721	$43,715
2	921	Office Supplies and Expenses	65,896	6,315	59,581	14,100	25,549	13,498	6,434
3	922	A&G Capital Transfer	(66,807)	(6,402)	(60,405)	(14,295)	(25,902)	(13,685)	(6,523)
4	923	Outside Services	362,302	34,748	327,553	77,442	140,640	74,136	35,335
5	924	Property Insurance	11,768	3,741	8,027	(7,267)	9,422	3,654	2,217
6	925	Injuries and Damages[d]	974,875	151,880	822,995	43,230	720,233	39,605	19,927
7	926	Pension and Benefits[a]	609,590	58,416	551,173	130,439	236,348	124,871	59,515
8	928	Regulatory Commission Expense	–	–	–	–	–	–	–
9	930	Miscellaneous General Expenses	6,775	649	6,126	1,450	2,627	1,388	661
10	935	Maintenance of General Plant	4,350	417	3,933	931	1,687	891	425
11		Total A&G Expenses	$2,416,505	$292,672	$2,123,833	$341,841	$1,284,206	$336,080	$161,707

(a) 2020 recorded adjusted cost does not include pension contribution.
(b) Excluding Franchise Fees.
(c) Table 8-6 shown above corrects the Electric Distribution, Total GRC and Total Non-GRC Columns of Table 8-9 in Exhibit (PG&E-10) Ch. 8 testimony.
(d) The allocation of wildfire liability insurance excluding to self-insurance is corrected to use TY 2023 wildfire liability insurance allocation factors.
(e) A correction is not needed for the GT Excess Line 401 item described in the response to Q6 (1) above because the error is not reflected in Tables 8-8, 8-9 and 8-10 from Exhibit (PG&E-10) Ch. 8 testimony.

TABLE 8-7[c]
DIFFERENCE FROM 2020 RECORDED ADJUSTED TO 2023 FORECAST A&G EXPENSE[a],[f]
(THOUSANDS OF NOMINAL DOLLARS)

Line No.	FERC Account	Description	Total Company[b]	Total Non GRC[b]	Total GRC	EG	Electric Distribution	Gas Distribution	GT
1	920	Administrative and General Salaries	$153,890	$14,747	$139,143	$32,929	$59,665	$31,523	$15,024
2	921	Office Supplies and Expenses	47,145	4,518	42,627	10,088	18,279	9,657	4,603
3	922	A&G Capital Transfer	(33,416)	(3,202)	(30,213)	(7,150)	(12,956)	(6,845)	(3,262)
4	923	Outside Services	27,904	2,673	25,232	5,977	10,805	5,722	2,727
5	924	Property Insurance	16,863	826	16,037	12,661	2,080	807	489
6	925	Injuries and Damages[d],[e]	(15,378)	(46,145)	30,767	9,817	8,808	7,851	4,290
7	926	Pension and Benefits[a]	188,112	18,027	170,086	40,252	72,934	38,534	18,366
8	928	Regulatory Commission Expense	–	–	–	–	–	–	–
9	930	Miscellaneous General Expenses	3,974	381	3,594	850	1,541	814	388
10	935	Maintenance of General Plant	(4,350)	(417)	(3,933)	(931)	(1,687)	(891)	(425)
11		Total A&G Expenses	$384,745	$(8,593)	$393,338	$104,494	$159,471	$87,173	$42,201

(a) 2023 Forecast does not include pension contribution.
(b) Excluding Franchise Fees.
(c) Table 8-7 shown above corrects the Electric Distribution, Total GRC and Total Non GRC Columns of Table 8-10 in Exhibit (PG&E-10) Ch. 8 testimony.
(d) The Electric Distribution LOB is corrected to include 100% of the TY 2023 forecasted $250 million in wildfire liability self-insurance costs.
(e) The allocation of wildfire liability insurance excluding self-insurance is corrected to use TY 2023 wildfire liability insurance allocation factors.
(f) A correction is not needed for the GT Excess Line 401 item described in the response to Q6 (1) above because the error is not reflected in Tables 8-8, 8-9 and 8-10 from Exhibit (PG&E-10) Ch. 8 testimony.

TABLE 8-8
PG&E'S NON-FORECAST ERRATA ADJUSTMENTS

Page No.	Line No.	Item	As of February 28, 2022	As Corrected
Page 8-6	Table 8-1 Line 3	Description of the methodology to allocate wildfire liability self-insurance costs.	Excluded a description of PG&E's Exhibit (PG&E-9) Ch. 3 proposal to allocate 100% of TY and PTY wildfire liability self-insurance costs to ED.	Added a description of PG&E's Exhibit (PG&E-9) Ch. 3 proposal to allocate 100 percent of TY and PTY wildfire liability self-insurance costs to ED.
Page 8-7	Table 8-2 Notes (b) and (c)	Table note additions.	Excluded a note describing the allocation of wildfire liability self-insurance costs.	Added note (b) describing the allocation of 100% of wildfire liability self-insurance costs to ED.
Page 8-7	Table 8-3 Line 3 GT&S Line 5 Total GRC Line 7 Other ET and GT Transmission Line 8 Total Non-GRC	GT Excess Line 401 costs and factor on the EOY plant allocation factors table.	Included GT Excess Line 401 costs in the GT&S and GRC EOY plant allocation factors.	Adjusted the table to remove GT Excess Line 401 costs from the GT& and Total GRC EOY plant allocation factors and added GT Excess Line 401 costs to ET and GT Transmission and Total Non-GRC costs for purposes of calculating GRC and Non-GRC EOY plant allocation factors.
Page 8-8	Table 8-4 Line 3 GT&S Line 5 Total GRC Line 8 ET and GT Other Transmission Line 9 Total Non-GRC	GT Excess Line 401 costs and factor on the blended labor and plant allocation factors table.	Included GT Excess Line 401 costs in the GT&S and GRC blended labor and plant allocation factors.	Adjusted the table to remove GT Excess Line 401 costs from the GT&S and Total GRC blended labor and plant allocation factors and added GT Excess Line 401 costs to ET and GT Other Transmission and Total Non-GRC costs for purposes of calculating GRC and Non-GRC labor and plant allocation factors.
Page 8-9, Page 8-10 and Page 8-11	Table 8-5, Table 8-6 and Table 8-7	Allocation of wildfire liability self-insurance costs to the LOBs.	Allocated wildfire liability self-insurance to NWT and ED and used the PTY wildfire liability insurance allocation factors to allocate self-insurance to NWT and ED.	Allocated 100% of wildfire liability self-insurance costs to ED and allocated the remaining wildfire liability insurance costs to NWT and ED using the TY 2023 wildfire liability insurance allocation factors.

PACIFIC GAS AND ELECTRIC COMPANY

CHAPTER 9

PAYROLL AND OTHER TAXES

THIS CHAPTER HAS NO REBUTTAL

PACIFIC GAS AND ELECTRIC COMPANY

CHAPTER 10

ELECTRIC, GAS, AND COMMON PLANT

THIS CHAPTER HAS NO REBUTTAL

PACIFIC GAS AND ELECTRIC COMPANY

CHAPTER 11

REBUTTAL TESTIMONY OF

BEATRIX H. GREENWELL

DEPRECIATION RESERVE AND EXPENSE

PACIFIC GAS AND ELECTRIC COMPANY
CHAPTER 11
REBUTTAL TESTIMONY OF
BEATRIX H. GREENWELL
DEPRECIATION RESERVE AND EXPENSE

TABLE OF CONTENTS

PACIFIC GAS AND ELECTRIC COMPANY
CHAPTER 11
REBUTTAL TESTIMONY OF
BEATRIX H. GREENWELL
DEPRECIATION RESERVE AND EXPENSE

A. Introduction

Q 1 Please state your name and the purpose of this rebuttal testimony.

A 1 My name is Beatrix Greenwell. This testimony responds to the direct testimony of the Public Advocates Office at the California Public Utilities Commission (Cal Advocates or CA),[1] The Utility Reform Network (TURN),[2] and the Indicated Shippers (IS) and Northern California Generation Coalition (NCGC) (collectively IS/NCGC).[3] I summarize parties' positions in Section B below.

B. Summary of Issues

Q 2 Please provide a summary of parties' positions to which you will be responding.

A 2 This testimony responds to parties' testimony concerns the following issues:

- PG&E's recommended depreciation expense and reserve, which is based on PG&E's recommended depreciation parameters (net salvage and survivor curves) and depreciation rates;
- PG&E's decommissioning accruals for hydroelectric facility decommissioning;
- Pleasant Creek Gas Storage depreciation and decommissioning;
- PG&E's use of the Units of Production (UoP) method;
- Software service lives for accounts EIP30303, GIP30302 and CMP30302; and
- Cost of Removal accounting records

Each issue is discussed in Section C below.

---

[1] CA-15 and CA-18.

[2] TURN-07 and TURN-18.

[3] IS/NCGC.

Q 3 Does PG&E have any non-forecast related adjustments or corrections to the February 28, 2022 version of its initial testimony and/or workpapers?

A 3 No.

C. PG&E's Response to Parties' Policy Positions

1. Depreciation

Q 4 What is the first issue you are addressing?

A 4 The first issue I am addressing is parties' positions on depreciation expense.

Q 5 What is Cal Advocates' recommendation on depreciation expense?

A 5 Cal Advocates recommends an overall reduction of $433.5 million[4] to PG&E's requested 2023 depreciation and amortization expense.

Q 6 Please summarize the depreciation parameter and rate recommendations of Cal Advocates.

A 6 Cal Advocates proposes changes in the service lives (average service lives and survivor curves) for one electric distribution account (364) and two gas distribution accounts (376.01 and 380).[5] It also proposes changes to net salvage estimates for four electric distribution (362, 364, 367, 368.01), one gas transmission account (367), and two gas distribution accounts (376.01, 380).[6] For all other gas distribution accounts (374, 375, 377, 378, 381, 383, 385, 386, 387), Cal Advocates proposes a depreciation rate change only from PG&E's proposed UoP method to a traditional straight-line method.[7]

Q 7 Does PG&E agree with Cal Advocates' recommendations?

---

[4] CA-15, p. 3, Table 15-1.

[5] CA-15, p. 11, lines 7-8; p. 13, lines 3-4; p. 15, lines 4-5.

[6] CA-15, p. 17, Table 15-5, column (d). PG&E notes that Cal Advocates' testimony presents incorrect net salvage parameters in CA-15, p. 2, lines 4-34; p. 4, Table 15-2; p. 5, Tables 15-3 and 15-4. CA-01, p. 22 repeats the incorrect summary of recommendations.

Cal Advocates confirmed that CA-15, Table 15-5 provides their correct recommended net salvage percentages. This was confirmed in Cal Advocates' response to PG&E Data Request PGE-CalAdvocates_005-Q05, dated 6/24/22, in Appendix A, at the end of this exhibit.

The net salvage parameters in Table 15-5 also agree with Cal Advocates' provided changes to the RO model tab "Depn_ScheduleAdj."

[7] CA-15, p. 3, lines 1-5.

A 7 No. PG&E does not agree with Cal Advocates' proposed depreciation reductions for the reasons discussed in Mr. Allis' rebuttal testimony in Exhibit (PG&E-23), Chapter 12.

Q 8 Please summarize TURN's depreciation parameter and rate recommendations.

A 8 TURN proposes to change the service lives (average service lives and Iowa survivor curves) for two electric accounts (353.02 and 353.03), eight electric distribution accounts (362, 364, 365, 367, 368.01, 368.02, 369.01, and 369.02), one gas transmission account (367) and four gas distribution accounts (378, 380, 381 and 383). TURN/Garrett proposes a change in lives for software intangible account 303 (three asset classes – electric, gas, and common). TURN/Garrett also proposes changes to net salvage estimates for five electric distribution accounts (362, 364, 367, 368.01 and 368.02), two gas storage accounts (352 and 353), one gas transmission account (367) and three gas distribution accounts (376.01, 378 and 380).[8]

TURN also proposes to retain the straight-line method for PG&E's gas distribution assets, and rejects PG&E's proposed UoP method.[9]

Q 9 Does PG&E agree with TURN's recommendations?

A 9 No, PG&E does not agree with TURN's proposed depreciation reductions for the reasons discussed in Mr. Allis' rebuttal testimony in Exhibit (PG&E-23), Chapter 12.

Q 10 What is the dollar impact of TURN's recommendations as compared with those of PG&E?

A 10 TURN recommends reductions to depreciation expense, excluding decommissioning, based on December 31, 2020 plant and accumulated depreciation as follows:[10]

1) Electric Division, $245.2 million;
2) Gas Division, $242.3 million; and
3) Common Division, $100.9 million.

---

8 TURN's recommended service lives and net salvage percentages are provided in TURN-18, p. 8, Table 3.

9 TURN-18, p. 5, lines 1-7 and Appendix D.

10 See TURN-18, p. 4, Table 1 for electric, gas, common and total reductions proposed by TURN.

The overall recommended reduction (compared to PG&E) is $588.3 million of depreciation expense applied to plant balances as of December 31, 2020.[11]

Q 11 What is the difference in PG&E's 2023 depreciation expense forecast due to depreciation rate changes, and parties' recommendations for changes in depreciation parameters and rates?

A 11 Cal Advocates' depreciation recommendations result in a $310 million decrease in depreciation expense due to depreciation rate changes as compared to PG&E's 2023 forecast depreciation expense.[12] TURN's recommended changes result in a much larger decrease of $584 million[13] compared to PG&E.

Q 12 Are the depreciation expense changes due to depreciation rates recommended by Cal Advocates and TURN reasonable?

A 12 No, they are not reasonable. Parties' positions are addressed in Exhibit (PG&E-23), Chapter 12.

Q 13 Please provide a summary of the depreciation positions of PG&E, Cal Advocates and TURN on service lives and net salvage.

A 13 Please see Tables 11-1 and 11-2 below, for the accounts where PG&E and parties provide different recommendations.

Q 14 Are there PG&E depreciation proposals which are not opposed by the parties?

A 14 Yes. Regarding depreciation parameters and rates, only the plant accounts listed in Tables 11-1 and 11-2 below are being contested by parties.

Table 11-1 below provides a comparison of the service life estimates

---

11 PG&E notes that in its comparison of TURN versus PG&E recommendations, for gas distribution TURN used PG&E's recommended UoP rates at 100 percent while PG&E has proposed in its request for 2023 using 25% of the UoP rates. Using PG&E's 2023 requested rates changes and applying them to TURN's 12/31/2020 plant amounts results in a change in TURN's reduction in gas from $242.3 million to $125.1 million, and TURN's total reduction from $588.3 million to $471.2 million.

12 The $310 million decrease was calculated using the depreciation rates provided in Cal Advocates' RO model provided June 2022 and applying them to PG&E's 2023 GRC forecast Plant provided in the March 2022 PG&E's RO Model.

13 TURN did not prepare a complete RO analysis for the test year, so it is not clear from TURN's testimony what the overall effect of TURN's recommendations is. Using PG&E's RO model and TURN's proposed depreciation rates, PG&E has tentatively calculated TURN's estimated 2023 depreciation expense adjustment.

authorized in both the 2017 and 2020 GRCs and the 2015 and 2019 GT&S rate cases[14] with the proposals of each party.[15] Table 11-2 below provides a comparison of the net salvage parameters proposed and authorized in the 2020 GRC and 2019 GT&S rate cases with the proposals of each party.[16]

---

14 See D.17-05-013, Settlement Agreement, Appendix C for the service lives authorized in the 2017 GRC. See D.20-12-005, Appendix D for the service lives authorized in the 2020 GRC. See D.19-09-025 for the authorized service lives included in depreciation stipulation Exhibit JS-03. See D.16-06-056 for the authorized service lives included in Joint Depreciation Stipulation (Exhibit Joint-1). The first number listed in the table is the Average Service Life (ASL) and the second is the Iowa curve type. Thus, for example, a 44-R2 survivor curve has a 44-year ASL and an R2 survivor curve type.

15 ASL Estimates are provided in Exhibit (PG&E-10) (Feb. 28, 2022), WP 11-1, Table 11-8, CA-15, p. 7 and TURN-18, p. 5, lines 17-21.

16 PG&E's 2019 GT&S and 2020 GRC proposed net salvage percentages are provided in 2019 GT&S workpapers supporting Ch. 14B, WP Table 14B-DS-1 and 2020 GRC workpapers supporting Exhibit (PG&E-10) (Feb. 28, 2022), WP 10-23, Table 10-5, respectively. See D.20-12-005, Appendix D for the net salvage authorized in the 2020 GRC. See D.19-09-025 for the authorized net salvage included in depreciation stipulation Exhibit JS-03. Estimates are provided in Exhibit (PG&E-10) (Feb. 28, 2022), , WP 11-1, Table 11-8, CA-15, and TURN-18.

TABLE 11-1
COMPARISON OF PG&E, CAL ADVOCATES AND TURN SERVICE LIFE ESTIMATES

Line No.	Account	Asset Class		2017 GRC/2015 GT&S Authorized Estimate	2020 GRC/2019 GT&S Currently Authorized Estimate	PG&E Estimate	Cal Advocates Estimate	TURN Estimate
1	Electric Intangible							
2	303.03	EIP30303	Computer Software	5-SQ	5-SQ	5-SQ	5-SQ	10-SQ
3	Electric Transmission							
4	353.02	ETC35302	Station Equipment - Step Up Transformers	55-R1.5	55-R1.5	55-R2	55-R2	63-R1.5
5	353.03	ETP35303	Station Equipment - Step Up Transformers (Combined Cycle)	55-R1.5	55-R1.5	55-R2	55-R2	63-R1.5
7	Electric Distribution							
8	362.00	EDP36200	Station Equipment	46-R1.5	46-R1.5	50-R1	50-R1	53-R1
9	364.00	EDP36400	Poles /Towers/Fixtures	44-R1.5	44-R2	44-R2	47-R1.5	52-R2
10	365.00	EDP36500	Overhead Conductors and Devices	46-R2	46-R2	44-R1.5	44-R1.5	48-R1.5
12	367.00	EDP36700	Underground Conductors and Devices	47-R3	50-R3	52-R3	52-R3	55-R3
13	368.01	EDP36801	Line Transformers - Overhead	32-R2.5	32-R2.5	32-R2.5	32-R2.5	35-R2.5
14	368.02	EDP36802	Line Transformers - Underground	31-R3	33-R2.5	34-R2.5	34-R2.5	37-R2.5
15	369.01	EDP36901	Services - Overhead	52-R2.5	55-R2.5	55-R2.5	55-R2.5	64-R2
16	369.02	EDP36902	Services - Underground	45-R4	50-R4	50-R4	50-R4	58-R3
17	Gas Intangible							
18	303.02	GIP30302		5-SQ	5-SQ	5-SQ	5-SQ	10-SQ
19	Gas Transmission							
20	367.00	GTP36700 GTP36703 GTE36700	Mains (excluding StanPac)	62-R2	66-R2	65-R2	65-R2	68-R2
21	367.00	GTS36700	Mains (StanPac)	62-R2	66-R2	65-R2	65-R2	68-R2
22	Gas Distribution							
23	376.00	GDP37601	Mains	57-R3	57-R3	57-R3	60-R3	57-R3
24	378.00	GDP37800	Measuring and Regulating Station Equipment	55-R2	55-R2	55-R2	55-R2	59-R2
25	380.00	GDP38000	Services	57-R3	57-R3	55-R3	59-R3	60-R3
26	381.00	GDP38100	Meters	28-S1	28-S1	28-S1	28-S1	31-S1
27	383.00	GDP38300	House Regulators	28-R2	28-R2	28-R2	28-R2	32-R2
28	Common							
29	303.02	CMP30302	Computer Software	5-SQ	5-SQ	5-SQ	5-SQ	10-SQ

TABLE 11-2
COMPARISON OF PG&E, CAL ADVOCATES AND TURN NET SALVAGE ESTIMATES

Line No.	FERC Account	Asset Class		2020 GRC/2019 GT&S PG&E Estimate	Currently Authorized Estimate	PG&E Estimate	Cal Advocates Estimate	TURN Estimate
1	Electric Distribution							
2	362.00	EDP36200	Station Equipment	-50%	-40%	-60%	-45%	-45%
3	364.00	EDP36400	Poles /Towers/Fixtures	-175%	-150%	-175%	-156%	-156%
5	367.00	EDP36700	Underground Conductors and Devices	-75%	-65%	-80%	-69%	-69%
6	368.01	EDP36801	Line Transformers - Overhead	-40%	-30%	-45%	-34%	-34%
7	368.02	EDP36802	Line Transformers - Underground	-25%	-25%	-35%	-35%	-28%
8	Gas Storage							
9	352.00	GUS35200	Wells	-15%	-15%	-25%	-25%	-18%
10	353.00	GUS35300	Lines	-50%	-35%	-50%	-50%	-39%
11	Gas Transmission							
12	367.00	GTP36700 GTP36703 GTE36700	Mains (excluding StanPac)	-70%	-54%	-75%	-59%	-59%
13	367.00	GTS36700	Mains (StanPac)	-70%	-54%	-75%	-59%	-59%
14	Gas Distribution							
15	376.00	GDP37601	Mains	-55%	-55%	-75%	-60%	-60%
16	378.00	GDP37800	Measuring and Regulating Station Equipment	-40%	-40%	-50%	-50%	-43%
17	380.00	GDP38000	Services	-124%	-81%	-100%	-86%	-86%

Q 15 Is PG&E sponsoring other rebuttal testimony to address Cal Advocates' and TURN's depreciation testimony?

A 15 Yes. As discussed above, Mr. Ned Allis (in Exhibit (PG&E-23), Ch. 12) is providing comprehensive rebuttal testimony on Cal Advocates' and TURN's depreciation recommendations. David Sawaya (Exhibit (PG&E-23) Ch. 12A) discusses PG&E's gas throughput forecast. Ajay Pathak discusses service life of software in Exhibit (PG&E-23), Chapter 12, pp. 147-149.

2. Decommissioning Expense Accruals

Q 16 What is the second issue you are addressing?

A 16 The second issue I am addressing is Cal Advocates' position on hydro decommissioning and TURN's position on gas storage decommissioning.

Q 17 Can you provide a summary of PG&E's and parties' recommendations?

A 17 Cal Advocates recommends a reduction of $38.3 million[1] to PG&E's 2023 requested decommissioning expense. TURN recommends a reduction of $3.0 million[2] to PG&E's 2023 requested decommissioning expense. Please see Table 11-3 below for PG&E's proposal and parties' adjustments to and forecast accruals for forecast year 2023.

Q 18 Do parties agree with PG&E's recommendations regarding the decommissioning accruals for its natural gas (fossil), fuel cell and solar facilities?

A 18 Yes. Parties have not opposed or recommended adjustments to PG&E's decommissioning proposal for its natural gas (fossil), fuel cell and solar facilities.[3]

Q 19 Are there other witnesses addressing parties' decommissioning proposals?

A 19 Yes. Rebecca Doidge provides rebuttal testimony in Exhibit (PG&E-18), Chapter 8, Section C.1. on Cal Advocates' hydro decommissioning recommendations.

---

1 CA-15, p. 3, lines 3-9.

2 TURN-07, p. 37, lines 1-3.

3 CA-15, p. 26, Table 15-7.

PG&E’s Pleasant Creek gas storage decommissioning proposal was opposed by TURN,[4] and is discussed in section C. below.

TABLE 11-3
SUMMARY OF PARTIES’ 2023 DECOMMISSIONING EXPENSE RECOMMENDATIONS
(THOUSANDS OF DOLLARS)

Line No.		Fossil	Solar	Kilarc-Cow CreekHydro	Hydro	Gas Storage	Total	Source
1	PG&E	$3,137	$5,986	5,896	$62,176	$(48,871)	$28,324	Exhibit (PG&E-10), chapter 11, (Feb. 28, 2022) WP Table 11-49.
2	Adjustments by Party:							
3	Cal Advocates	0	0	0	$(38,270)	0	$(38,270)	CA-15, Table 15-7, p. 26
4	TURN	0	0	0	0	$(3,040)	$(3,040)	TURN-07, p. 37, lines 1-3.
5	Parties' Recommendations:							
6	Cal Advocates	$3,137	$5,986	$5,896	$23,906	$(48,871)	$(9,946)	
7	TURN	$3,137	$5,986	$5,896	$61,176	$(51,911)	$41,897	

3. Depreciation and decommissioning expenses for PG&E’s Pleasant Creek gas storage facility

Q 20 What is the third issue you are addressing?

A 20 The third issue I am addressing is TURN’s position on inclusion of depreciation and decommissioning expenses in this case for PG&E’s Pleasant Creek gas storage facility.[5]

Q 21 What is(are) the difference(s) between PG&E’s position on Pleasant Creek and TURN’s position?

A 21 PG&E’s testimony includes depreciation for one year for Pleasant Creek in the amount of $4.338 million,[6] and decommissioning of $3.04 million per year for 4 years, 2023-2026.[7] TURN recommends the Commission reduce

[4] TURN-07, p. 35, line 10 to p. 37, line 3.

[5] TURN-07, p. 35, line 10 to p. 37, line 3.

[6] Exhibit (PG&E-10) (Feb. 28, 2022), WP 11-66.

[7] Exhibit (PG&E-10) (Feb. 28, 2022), WP 11-63.

PG&E's forecast by $4.338 million in 2023 depreciation expense and $3.04 million per year for decommissioning.[8]

Q 22 Do you agree with TURN's position? Please discuss.

A 22 No, PG&E does not support TURN's position on this issue. PG&E is attempting to sell the Pleasant Creek facility. There is currently no signed purchase and sale agreement. It is proper for the Commission to adopt PG&E's proposed depreciation and decommissioning, as there is no final sale. The Commission should address the calculation of the gain or loss, and any refund or collection from customers, including depreciation and decommissioning, in the Section 851 filing, which is the proper venue for these adjustments. In this way, customers will be made whole if there is a completed sales transaction.

Q 23 Are there other gas storage decommissioning proposals that TURN supports?

A 23 Yes, TURN accepts PG&E's proposal to return Los Medanos depreciation and decommissioning costs to ratepayers in the test year 2023.[9]

4. PG&E's Use of the Units of Production method (UOP) to calculate depreciation for Gas Distribution assets

Q 24 What is the fourth issue you are addressing?

A 24 The fourth issue I am addressing is the use of the Units of Production method by PG&E in the 2023 GRC in determining its gas distribution depreciation rates, which has been opposed by several parties.

Q 25 Is there other rebuttal testimony that addresses parties' positions on the UoP method?

A 25 Yes, witness Mr. Allis provides rebuttal testimony on this topic in Exhibit (PG&E-23), Chapter 12, Section C.2.

Q 26 What are the differences between PG&E's position on the use of UoP method to determine gas distribution rates and Cal Advocates', TURN's and IS/NCGC's positions?

---

8 TURN-07, p. 35, line 10 to p. 37, line 3.

9 TURN 07, p. 2, lines 19 20.

A 26 PG&E's proposal to adopt the UoP method is in its opening testimony of in Exhibit (PG&E-10), Chapter 11, Section C.9 and Chapter 12, Section D.2.[10] PG&E's proposal to move to a UoP methodology makes sense because gas throughput is expected to decline over the next few decades as the State's energy policies are implemented. When customers either leave the gas system or significantly reduce consumption (or both), there are fewer customers from whom to collect the remaining costs. As such, PG&E has timely proposed an equitable depreciation proposal, a shift to the UoP method with throughput from E3's medium gas demand scenario.[11] Further, PG&E's proposal considers the bill impacts on current customers and the concept of gradualism, because PG&E proposed to use the more moderate medium forecast (as opposed to medium-high) and has proposed to phase in the impact of the change over four years.[12]

In contrast, Cal Advocates rejects the UoP proposal. Cal Advocates recommends the Commission retain the straight-line method of depreciation for the current GRC.[13] Cal Advocates believes the UoP proposal should be considered initially in R.20-01-007 (Long Term Planning OIR),[14] presumably to postpone an increase in depreciation expense which it deems "premature."[15]

TURN also objects to PG&E's UoP proposal and also proposes the UoP proposal be considered instead in the Long Term Planning OIR.[16] TURN quotes the Commission in the Long Term Planning OIR where it stated that gas utilities should "maintain safe and reliable gas systems at just and reasonable rates, and ***with minimal or no stranded costs***".[17] TURN

---

10 Exhibit (PG&E-10) (Feb. 28, 2022), Ch. 11 and Ch. 12.

11 Exhibit (PG&E-10) (Feb. 28, 2022), p. 12-25 to p. 12-42, Section D.2.

12 Exhibit (PG&E-10) (Feb. 28, 2022), p. 11-26 to p. 11-27, Section C.9.c.

13 CA-15, p. 3, lines 1-5.

14 Order Instituting Rulemaking (OIR) to Establish Policies, Processes, and Rules to Ensure Safe and Reliable Gas Systems in California and Perform Long-Term Gas System Planning. (Jan. 16, 2020). Rulemaking (R.) 20-01-007.

15 CA-15, p. 25, lines 10-14.

16 TURN-18, Appendix D.

17 TURN-18, Appendix D, p. 100, line 21 to p. 101, line 1 (emphasis added).

seems to believe that part of the cost should be borne by customers. TURN states:

> the Commission should reject PG&E's proposal for the UoP method because it does not represent a balanced approach to addressing the stranded cost risk, which is a risk faced by both PG&E's shareholders and its future customers. PG&E's testimony here focuses on the risk that future customers will pay higher rates if electrification results in retirement of gas distribution plant before the end of the service life adopted for depreciation purposes, and only seeks to burden current customers with higher costs to reduce that future risk[18]

TURN also opines that: "If steps are warranted now to reduce the future stranded cost risk from decarbonization, the burden of such steps should fall on ***both ratepayers and shareholders***."[19] To the extent that TURN is arguing that shareholders should fund part of the depreciation of prudent investments in plant due to climate change policies in the State, PG&E disagrees with this proposal. It would be inappropriate to assess shareholders for Utility costs incurred prudently, and as the change is due to Commission, State and local directives it is beyond its control.

IS/NCGC also recommends the Commission reject the UoP proposal.[20] IS/NCGC states that throughput could be reduced,[21] but PG&E did not adequately support the throughput forecast chosen to calculate the UoP rates. IS/NCGC also states the building conversions to electric present problems, including who will bear the cost, whether the utility has an obligation to serve gas customers, or whether this obligation can be redefined.[22] IS/NGCG also questions the speed of the transition from gas to electric, and proposes to wait until the completion of the long term planning OIR.[23]

Q 27 What important considerations do parties fail to address in their testimonies?

---

18 TURN-18 Appendix D, p. 101, lines 5-10.

19 TURN-18, Appendix D, p. 101, lines 15-17 (emphasis added).

20 IS/NCGC-2, p. 2, lines 9-13.

21 IS/NCGC-1, p. 4, lines 14-18.

22 IS/NCGC-1, p. 7, lines 21-26.

23 IS/NCGC-1, p. 9, lines 9-15.

A 27 Parties' proposals ignore the potential impacts of California's long-term carbon neutrality goal; fail to recognize that depreciation is a forecast of many decades into the future, and, therefore, must be used in the calculation of depreciation rates; that depreciation rates will be further updated in future cases. They present as reasoning the assertion that the future is not known but make no effort to consider long-term impacts of State climate goals. As a result, their positions create unnecessary burden on future generations of customers.

Q 28 Do you agree with Cal Advocates, TURN and IS/NCGC's position? Please discuss.

A 28 No, PG&E does not support Cal Advocates, TURN and IS/NCGC's position on this issue for the following reasons:

- The GRC is the proper venue for this proposal, as it is the earliest and best opportunity to adjust rates and achieve intergenerational equity;[24]
- PG&E has performed a complete and thorough depreciation study for this GRC and depreciation witnesses are available in this proceeding to provide expert testimony on depreciation;[25]
- Authorized depreciation rates are already too low due to past applications of gradualism;[26]
- A significant transformation of the energy industry—as will occur to achieve Net Zero by 2045—will result in a need to recover capital more quickly than in the past;[27]
- PG&E's proposal is consistent with the concept of gradualism.
  - PG&E's proposal results in an increase in depreciation but lower depreciation than several possible scenarios;[28] and
  - PG&E's proposal is phased in over four years.[29]

---

24 Exhibit (PG&E-10) (Feb. 28, 2022), p. 11-20 to p. 11-26, Section 9.a and 9.b.

25 Ned Allis is sponsoring Exhibit (PG&E-10) (Feb. 28, 2022), Ch. 12, TURN-18, CA-15, IS/NCGC.

26 Exhibit (PG&E-23), Ch. 12, Section C.1.d.

27 Exhibit (PG&E-23), Ch. 12, Section B.2.

28 Exhibit (PG&E-23), Ch. 12, p. 12-6.

29 Exhibit (PG&E-10) (Feb. 28, 2022), p. 11-27, lines 11-25.

- Parties have not proposed an alternative method that assures equitable cost recovery.

The Commission has previously urged PG&E to move costs into rates in a timely manner,[30] and PG&E's proposal does that. As discussed in my opening testimony,[31] the Commission has addressed in previous proceedings the importance of changing depreciation rates when changes in lives are expected in order to recover asset investments over their remaining lives. The Commission describes in D.11-05-018 that PG&E and Southern California Edison Company (SCE) did not take the earliest opportunity to significantly reduce the recovery period to match the shortened lives of electromechanical meters. The Commission states:

> The shorter remaining lives would have recovered the investment so that the assets would be fully depreciated by the end of the deployment of the AMI meters. However, this was not proposed by either PG&E or SCE because of the impact it would have on rates…We agree that PG&E could have alternatively shortened the expected life of the meters, on a prospective basis, in calculating depreciation rates. However, they did not, and even if they had, the question of appropriate ratemaking for a large amount of prematurely retired plant would need to be analyzed in the same way as was done in this decision for PG&E's proposal.

Q 29 What is the problem with deferring the cost recovery of PG&E's gas assets?

A 29 The timing of Phase II (Track 2) of R.20-01-007 could result in the deferral of the implementation of ratemaking changes until PG&E's 2027 GRC.[32] To avoid both stranded costs of PG&E's gas assets as well as an unfair allocation of costs to customers, PG&E is bringing the UoP cost recovery proposal to the Commission for consideration in this 2023 GRC. PG&E is addressing the expected gas throughput decline and change in the forecast life of PG&E's gas assets at this earlier opportunity, rather than deferring cost recovery implementation and further burdening future customers with depreciation costs that should be shared by existing customers.

---

30 D.11-05-018, p. 51 stated that PG&E and Southern California Edison Company (SCE) did not take the earliest opportunity to significantly reduce the recovery period to match the shortened lives of electromechanical (AMI) meters.

31 See Exhibit (PG&E-10) (Feb. 28, 2022), p. 11-24 to p. 11-26.

32 Exhibit (PG&E-10) (Feb. 28, 2022), p. 11-24, lines 18-22.

Both Mr. Allis and I discuss in our direct testimony[33] that waiting to incorporate the impacts of decarbonization on the depreciation of gas assets will cause both larger increases in depreciation and a higher rate base in future rate cases. In his rebuttal testimony in Exhibit (PG&E-23), Chapter 12, section 2.c., Mr. Allis provides additional discussion and examples of the costly impacts of deferring implementation of the UoP method.

Additionally, the Commission has recognized these demand and throughput decline issues and intergenerational inequity concerns in (R.) 20-01-007 (see my opening testimony, Exhibit (PG&E-10), Chapter 11 (Feb. 28, 2022) p. 11-21, line 22 to p. 11-23, line 14, which provides several Commission cites in R.20-01-007 (Jan. 27, 2020). The Commission states:

> Compliance with local and statewide greenhouse gas legislation will cause the demand for natural gas, in particular fossil-derived gas, the primary type of gas supplied through the gas system in California, to decline over the next 25 years. Statewide Renewable Portfolio Standard (RPS) goals require retail sellers of electricity to procure a certain percentage of generation from renewable sources over the next 25 years. As retail sellers procure less energy from gas-fired generators, which comprise approximately 30 percent of the demand for natural gas in California, the gas throughput assigned to these customers will also decline, thereby allocating more costs to remaining customers, such as residential, small commercial and industrial ratepayers.
>
> …over time, segments of the natural gas pipeline system will no longer be used and useful and therefore, ineligible for rate recovery from ratepayers, potentially leaving the gas utilities with an excessive amount of stranded costs. Ratepayers who remain on the system the longest will likely be customers who may not be able to afford the switch from gas to electric home heating and cooling systems, yet these customers would be required to cover the revenue requirements of the remaining pipeline system at higher rates.

PG&E therefore recommends that the Commission approve the UoP method proposed by PG&E in this 2023 GRC instead of deferring to the OIR. Given the timing of the OIR schedule it is likely that the OIR, proceeding may push the implementation of the UoP method to the 2027 GRC, losing valuable time for cost recovery. PG&E recommends strongly

---

33 Exhibit (PG&E-10) (Feb 28, 2022), Ch. 11 and Ch. 12.

that the proper time and venue for consideration and adoption of PG&E's UoP proposal is the 2023 GRC. The Commission should adopt the UoP method to address the future as it is seen and understood at this time. If the Commission does not adopt the UoP method, PG&E alternatively recommends that the Commission rule that the cost recovery of PG&E's gas system is assured and will be addressed in the OIR, through implementation of appropriate depreciation.

Q 30 How does PG&E recommend the Comission evaluate gas distribution depreciation in this case?

A 30 PG&E recommends the Commission adopt PG&E's proposal to determine gas distribution asset depreciation rates using the UOP method. This method has the benefits of:

- Mitigating intergenerational inequity and customer group inequity;
- Mitigating higher rates later in the asset lives;
- Mitigating the risk of stranded costs; and
- Providing customers with lower overall cost as rate base decreases earlier in the recovery period.

5. Software lives – increase life from 5 to 10 years

Q 31 What is the fifth issue you are addressing?

A 31 The fifth issue I am addressing is TURN's position on the useful life of software accounts CMP30302, EIP30303, GIP30302.

Q 32 What is the difference(s) between PG&E's position on software account depreciation and TURN's position?

A 32 PG&E's witness, Mr. Ned Allis has proposed an average service life of 5 years for Account CMP30302.[34]

In contrast TURN proposes a 10-year service life.[35]

Q 33 Do you agree with TURN's position? Please discuss.

A 33 PG&E does not support TURN's position on this issue. The primary rebuttal on this issue is presented in Exhibit (PG&E-23), Chapter 12, sponsored by

---

34 Exhibit (PG&E-10) (Feb. 28, 2022), p. 12-63.

35 TURN-18, p. 57, lines 6-10.

Mr. Allis, and Exhibit (PG&E-23),[36] Chapter 12, presented by Ajay Pathak.[37]

Q 34 How does PG&E recommend the Commission evaluate Software lives in this case?

A 34 PG&E recommends the Commission approve the proposed 5-year life for account CMP30302. EIP30303, GIP30302. As there is another account, CMP30304 with a 13-year life, if parties wish, they may recommend certain projects be evaluated for transfer to that account, but as Mr. Allis and Mr. Pathak explain, it is inappropriate to change average service lives for CMP30302, EIP30303 and GIP30302.

6. Cost of Removal (COR) Records

Q 35 What is the final issue you are addressing?

A 35 The final issue I am addressing is Cal Advocates' analysis on net salvage and PG&E's recorded cost of removal (COR). Cal Advocates questions the reliability of PG&E's recorded COR data. Based on its claims that the data is insufficient, Cal Advocates disputes our net salvage recommendations included in the depreciation study. PG&E has recorded several journal entries to recorded cost of removal that Cal Advocates questioned.

- Cal Advocates stated that PG&E has incorrectly (a) not reduced the 2016 COR data to reflect a disallowance, and (b) added the disallowed costs in 2020, which duplicated and increased recorded COR.[38] As a result, Cal Advocates questions the reliability of the recorded data[39] and alleges that it could not verify COR or that PG&E didn't inflate or include duplicate entries;[40]
- Cal Advocates confuses the need to include disallowance journal entries to the recorded cost of removal to reduce rate base, which is required by Commission order, with the need to remove the disallowance entries to cost of removal from the depreciation study data, which would not be

---

36 Exhibit (PG&E-23) p. 12-137 line 6 to p. 12-147 line 11.

37 Exhibit (PG&E-23) p. 12-147, line 12 to p. 12-149, line 27.

38 CA-15, p. 20, lines 14-16.

39 CA-15, p. 20, lines 20-21.

40 CA-15, p. 20, lines 23-24.

appropriate. If the cost disallowance were included in the depreciation study, it would distort net salvage ratios;[41] and

- Cal Advocates states that they were not able to check recorded COR entries in the books to invoices or supporting documents.[42]

Q 36 What is PG&E's response to Cal Advocates' statements regarding PG&E's accounting entries?

A 36 PG&E's COR records are accurate. Cal Advocates' descriptions of PG&E's COR entries and records as inadequate may be based on an incomplete understanding of PG&E's accounting procedures for COR.[43] PG&E's COR data is properly recorded using standard processes and well-documented journal entries. This process was discussed numerous times in meetings between Cal Advocates and PG&E[44] and in PG&E's discovery responses.

Q 37 Is Cal Advocates' description of PG&E's records as they relate to the depreciation study accurate?

A 37 No. Cal Advocates is claiming that PG&E did not adequately reflect two disallowances in the depreciation study. PG&E's cost of removal and the journal entries related to D.16-06-056 (2015 GT&S disallowance) and D.20-05-019 (Wildfire OII disallowance) were properly recorded in PG&E's books and records. The depreciation study properly ***excluded*** the cost disallowance entries because if these amounts were included, it would distort net salvage ratios. The basis to exclude the journal entries in the depreciation study is discussed in detail in rebuttal testimony in Exhibit (PG&E-23), Chapter 12.[45] Disallowance related cost of removal entries were properly excluded from the depreciation study for reasons described in

---

[41] CA-15, p. 19, lines 12-19.

[42] CA-15, p. 20, lines 18- 24.

[43] CA-15, p. 19, line 20 to p. 20, line 18.

[44] A review of Cal Advocates questions and requests for PG&E's cost of removal data was accomplished and agreement reached on supporting details to be provided in meetings (8/13/2021 and 1/20/2022) between PG&E and Cal Advocates. PG&E explained the entries and provided the support agreed upon with Cal Advocates in the many discovery responses PG&E provided.

[45] Exhibit (PG&E-23), Ch. 12, Q and A 164-167.

Exhibit (PG&E-23), Chapter 12,[46] and properly had no bearing on Mr. Allis' net salvage recommendations.

Q 38 Was Cal Advocates' given the data needed to review the details of costs recorded to COR?

A 38 Yes. As documented in responses to many Cal Advocates' data requests and in two meetings,[47] PG&E provided the accounting and business process documentation to Cal Advocates to explain how order costs settle to COR, and the detailed costs for agreed upon planning orders. Please see below.

Q 39 Can you describe the data responses PG&E provided to Cal Advocates on the accounting for cost of removal?

A 39 The following is a partial list of the data requests and the topics covered in response to Cal Advocates' questions on PG&E's cost of removal:[48]

1) CalAdvocates_016-Q01 (f) – PG&E provided in excel the recorded cost of removal detail to support the depreciation study workpaper amounts by asset class, planning order, and major work category (MWC);
2) CalAdvocates_016-Q01 (g) – PG&E summarized the August 13, 2021 meeting with Cal Advocates' witness Anusha Nagesh and the agreed upon level of detail to include for the Cal Advocates' analysis of cost of removal. PG&E provided agreed upon detail of cost of removal and journal entries;
3) CalAdvocates_052-Q08 – PG&E explained how and where in workpapers, PG&E recorded cost of removal for property retired due to wildfires in years 2016 to 2020; PG&E records cost of removal in accordance with accounting procedures prescribed in FERC USOA for Account 108;

---

46 *Ibid.*

47 These two meetings were with the original Cal Advocates witness and were not attended by the current Cal Advocates witness, Mr. Burns, which may have added to Cal Advocates' misunderstanding.

48 PG&E's response to Data Request CalAdvocates_016-Q01, dated 8/20/21; CalAdvocates_052-Q08, dated 9/15/21; CalAdvocates_083-Q06, Q09, Q10 and Q12, dated 10/22/21, also Q07, Q08, dated 10/8/21; CalAdvocates_113-Q04, dated 11/2/21; CalAdvocates_126-Q01, dated 11/12/21; CalAdvocates_236-Q01, Q02, dated 2/9/22; CalAdvocates_237-Q01, Q02, dated 2/9/21; TURN_026-Q17, dated 10/6/21 in Appendix C at the end of this exhibit.

4) CalAdvocates_083-Q06 – PG&E described the process for recording removal costs, including discussion of accounting settlements to FERC accounts. PG&E provided a diagram which explained how costs are charged to capital orders, and how those charges are recorded as cost of removal and plant, and a numerical example. PG&E also provided cost details for EDP36200 (Station Equipment), as requested, for order 74001604, which supports planning order 5767700;
5) CalAdvocates_083-Q07 – PG&E provided further explanation on PG&E's process to segregate costs charged to a capital order, and how costs are assigned to cost of removal and plant additions for accounting purposes. PG&E provided its Capital Job Estimate Standard, and key extracts therefrom;
6) CalAdvocates_083-Q08 – PG&E explained how PG&E's incurred cost of removal was removed from accumulated depreciation (and rate base) in compliance with D.20-05-019, to ensure cost disallowances are not recovered from customers. PG&E reiterated that journal entries were made to remove cost of removal capital expenditures from accumulated depreciation;
7) CalAdvocates_083-Q09 – PG&E explained the 2016 journal entry related to the 2015 GT&S Decision (D.16-06-056) to reflect plant disallowance for accounting and depreciation study purposes. Further, the journal entry was properly excluded from the depreciation study as discussed in Exhibit (PG&E-23), Chapter 12;
8) CalAdvocates_083-Q10 – PG&E explained a specific journal entry to record the reclassification for cost of removal of $4.6 million and how PG&E determined the cost of removal amount. This journal entry was recorded to reclassify costs from plant to COR in order to correctly state the plant and accumulated depreciation balances at the end of the year.
9) CalAdvocates_083-Q12 – PG&E explained that PG&E uses cradle to grave accounting and does not re-capitalize plant that is moved or transferred from one location to another;
10) CalAdvocates_113 Q04 – PG&E provided an explanation of the journal entries to cost of removal and provided a diagram clearly showing how the entries were recorded and result in no double counting of costs;

11) CalAdvocates_126 Q01 – PG&E shared the Company's capital accounting policies submitted in TURN_26 Q17; and

12) CalAdvocates_236 Q01, Q02 & CalAdvocates_237 Q01, Q02 – PG&E provided all the detailed transactions for the accounts requested by Cal Advocates, for entries to record cost of removal, including general ledger account, by month and year, and attachments that showed the supporting documents for these entries.

Q 40 What was discussed in the meetings held between PG&E and Cal Advocates on COR?

A 40 PG&E met with Cal Advocates witness Anusha Nagesh and her supervisor, Tamera Godfrey on August 13, 2021. PG&E answered Cal Advocates' questions, and discussed the data to be provided to satisfy a data request (CalAdvocates_016). Cal Advocates and PG&E met again on January 20, 2022 and PG&E provided at this meeting further clarification on additional discovery questions.

Q 41 Do you have further comments?

A 41 Yes. PG&E's fixed asset module (subsidiary ledger), PowerPlan, and its general ledger, SAP, are used by many utilities. The accounting procedures to record journal entries are quite standard as well. PG&E had provided adequate information for Cal Advocates' review of the requested costs. As such, the Commission should find that PG&E has provided support for its cost of removal records.

Q 42 What should the Commission conclude about PG&E's cost of removal records?

A 42 PG&E's cost of removal records are complete and accurate.

Q 43 Does this conclude your rebuttal testimony?

A 43 Yes, it does.

PACIFIC GAS AND ELECTRIC COMPANY

CHAPTER 12

REBUTTAL TESTIMONY OF

NED W. ALLIS

DEPRECIATION STUDY

PACIFIC GAS AND ELECTRIC COMPANY
CHAPTER 12
REBUTTAL TESTIMONY OF
NED W. ALLIS
DEPRECIATION STUDY

TABLE OF CONTENTS

PACIFIC GAS AND ELECTRIC COMPANY
CHAPTER 12
REBUTTAL TESTIMONY OF
NED W. ALLIS
DEPRECIATION STUDY

TABLE OF CONTENTS
(CONTINUED)

PACIFIC GAS AND ELECTRIC COMPANY
CHAPTER 12
REBUTTAL TESTIMONY OF
NED W. ALLIS
DEPRECIATION STUDY

TABLE OF CONTENTS
(CONTINUED)

PACIFIC GAS AND ELECTRIC COMPANY
CHAPTER 12
REBUTTAL TESTIMONY OF
NED W. ALLIS
DEPRECIATION STUDY

A. Introduction

Q 1 Please state your name and the purpose of this rebuttal testimony.

A 1 My name is Ned Allis. This testimony responds to the direct testimony of the Public Advocates Office at the California Public Utilities Commission (Cal Advocates),[1] The Utility Reform Network (TURN),[2] and the Indicated Shippers (IS) and the Northern California Generation Coalition (NCGC) (IS/NCGC for the combined entities).[3]

Q 2 Are there any portions of this rebuttal testimony that are sponsored by another PG&E witness?

A 2 Yes. Section C.5.b is sponsored by PG&E witness Ajay Pathak.

B. Summary of Issues

1. Introduction

Q 3 Please provide a summary of parties' positions to which you will respond.

A 3 This testimony responds to Cal Advocates, TURN and IS/NCGC's testimony opposing PG&E's proposal to incorporate the future impacts of significant carbon reductions on gas depreciation. It also responds to Cal Advocates' and TURN's testimony related to the service life and net salvage estimates in the depreciation study. Each of these parties opposes PG&E's proposal to use the Units of Production (UoP) method of depreciation for gas distribution assets and instead each proposes to ignore – at least for this General Rate Case (GRC) -- any potential impacts of California's carbon neutrality goal, which will be less than two decades away upon the conclusion of this GRC cycle. To underscore that they have not even attempted to consider the long-term impacts of carbon neutrality, Cal

---

1 CA-18.

2 TURN-18.

3 IS/NCGC-1.

Advocates and TURN also propose longer service lives and less negative net salvage (i.e., lower cost of removal) for several of PG&E's asset classes, including asset classes TURN believes will have shorter service lives in the future.[4]

Q 4 Please summarize the impacts of the issues you address.

A 4 Table 12-1 below provides a summary of the recommended depreciation rates and accruals by plant function as of the test year of the depreciation study of December 31, 2020. The table also provides a comparison to the currently-authorized depreciation rates and accruals. The impact of each party's proposal as of December 31, 2023 is summarized in Exhibit (PG&E-23), Chapter 11.

---

[4] See TURN's response to PG&E's Data Requests PGE_TURN006-Q07 and PGE_TURN006-Q08.

TABLE 12-1
COMPARISON OF PG&E, CAL ADVOCATES, TURN AND IS/NCGC DEPRECIATION PROPOSALS AS OF DECEMBER 31, 2020
(MILLIONS OF DOLLARS)

Line No.	FERC Account	Currently Authorized Rate	Currently Authorized Accrual	PG&E Rate	PG&E Accrual	Cal Advocates Rate	Cal Advocates Accrual	TURN Rate	TURN Accrual	IS/NCGC Rate	IS/NCGC Accrual
1	Electric Plant										
2	Intangible	3.07	$10.2	3.15	$10.5	3.15	$10.5	2.62	$8.7	3.15	$10.5
3	Steam Production	3.57	26.4	3.52	26.1	3.52	26.1	3.52	26.1	3.52	26.1
4	Hydro Production	2.94	129.7	2.59	114.0	2.59	114.0	2.59	114.0	2.59	114.0
5	Other Production	4.23	51.8	4.06	49.7	4.06	49.7	4.06	49.7	4.06	49.7
6	Transmission	2.75	17.3	2.84	17.9	2.84	17.9	2.81	17.7	2.84	17.9
7	Distribution	4.00	1,390.2	4.37	1,519.6	3.95	1,375.2	3.67	1,277.4	4.37	1,519.6
8	General	6.04	46.4	6.01	46.2	6.01	46.2	6.01	46.2	6.01	46.2
9	Total Electric Plant	3.90	$1,672.0	4.08	$1,783.9	3.82	$1,639.6	3.59	$1,539.8	4.08	$1,783.9
10	Gas Plant										
11	Intangible	31.07	$1.0	81.31	$2.6	81.31	$2.6	15.38	$0.5	81.31	$2.6
12	Production	1.75	0.0	1.84	0.0	1.84	0.0	1.84	0.0	1.84	0.0
	Underground Storage	2.32	21.5	2.79	25.9	2.79	25.9	2.66	24.7	2.79	25.9
13	Local Storage	2.54	0.4	2.44	0.4	2.44	0.4	2.44	0.4	2.44	0.4
	Transmission	2.28	159.5	2.70	188.7	2.44	170.6	2.42	168.8	2.70	188.7
	Transmission – Stanpac	2.49	1.3	2.91	1.5	2.63	1.4	2.59	1.4	2.91	1.5
14	Distribution	2.99	386.1	4.68	604.1	3.12	380.2	2.99	385.5	3.49	450.6
15	General	4.27	20.9	5.24	25.6	5.24	25.6	5.24	25.6	5.24	25.6
16	Total Gas Plant	2.76	$590.8	3.97	$848.9	2.84	$606.8	2.84	$606.9	3.97	$695.3
17	Common Plant	8.50	$520.7	8.76	$536.1	8.76	$536.1	7.11	$435.2	8.76	$536.1
18	Total Depreciable Plant	3.95	$2,782.5	4.50	$3,168.9	3.95	$2,782.5	3.67	$2,581.9	4.28	$3,015.3

I note that the IS/NCGC column in Table 12-1 also shows the impact of adopting all of PG&E's proposals except the UoP Method. If the Commission were to opt to defer recognition of the depreciation impact of potentially significant declines in gas demand, then the depreciation rates supporting this column would be a more reasonable way to adjust PG&E's proposal to remove only the impact of the UoP proposal while retaining more reasonable service life and net salvage estimates than those proposed by Cal Advocates or TURN. As I discuss in detail, Cal Advocates' and TURN's service life and net salvage proposals will only worsen the cost recovery issues that the Commission will eventually need to address.

Q 5 Why will Cal Advocates and TURN's proposals make these cost recovery issues worse?

A 5 As can be seen in the table above, both parties propose to decrease depreciation for the gas distribution and electric distribution functions of plant when compared to the currently authorized depreciation expense. We can be quite certain that reducing depreciation for these functions of plant is unreasonable for at least the following reasons:

1. Achieving net zero greenhouse gas (GHG) emissions will increase depreciation, both because of declines in gas demand and because of the need to upgrade the electric system to manage both net zero generation and increased loads from electric vehicles.
2. PG&E's currently authorized depreciation rates are lower than supported in prior depreciation studies due to the Commission's preference for the concept of gradualism.

Both the Uniform System of Accounts (USOA) and the Commission's Standard Practice U-4 define depreciation specifying that factors including obsolescence, changes in demand and the requirements of public authorities must be considered when determining depreciation.[5] This means that, when determining the most reasonable depreciation rates, we must think about what will occur over many decades in the future. It follows that we must consider the impact on depreciation of achieving net zero GHG emissions. Not only do TURN, Cal Advocates and IS/NCGC argue we

---

5 See, 18 C.F.R. § 201, Definition 12B; *also* see Standard Practice U-4, p. 6.

should not do so, but TURN and Cal Advocates even propose to decrease depreciation for electric and gas distribution assets. As I discuss in detail, pretending these capital recovery issues do not exist will not make them go away. Instead, they will only grow to be larger issues in the future. If the Commission declines to adopt PG&E's proposals, it should at least consider the impact of GHG emissions reductions on depreciation and, therefore, must reject Cal Advocates, TURN and IS/NCGC's proposals.[6]

Q 6 How will you address the proposals of each party in your rebuttal testimony?

A 6 I will separately address each proposal related to the UoP Method, service lives and net salvage. However, I first address several important concepts and circumstances that impact depreciation that are important for the Commission to consider. The first of these is how climate change policies and significant reductions in GHG emissions by 2045 will impact depreciation for both current and future generations of customers.

2. Climate Change and Depreciation

Q 7 What depreciation issues does the Commission need to consider in this GRC from a policy standpoint?

A 7 The Commission has a daunting challenge before it, not just for this GRC but also because of the broader range of policy issues it must consider related to California's goal to achieve net zero greenhouse gas emissions by 2045 (referenced as "Net Zero by 2045" throughout my testimony). In Table 12-7 of Exhibit (PG&E-10) I presented various scenarios showing how Net Zero by 2045 could impact gas depreciation. These scenarios were based on several forecasts of gas demand based on different potential pathways to Net Zero by 2045. While these scenarios vary depending on the specific pathway (for example, they differ on the degree of electrification that occurs over the next three decades), they all result in fairly significant increases in depreciation. Accordingly, we can be reasonably certain that the

---

6 I note here that I have presented the resultant depreciation for several different scenarios for gas assets in Exhibit (PG&E-10) (Feb. 28, 2022), p. 12-36, Table 12-7, based on different assumptions about the future. If the Commission's outlook for the gas industry differs from PG&E's, any of these would be more reasonable than the other parties' proposals in this GRC (with the exception of the Company's currently authorized depreciation).

Company's current level of depreciation, which is based largely on how it has operated in the past, is too low.

Q 8 Do you find this conclusion to be surprising?

A 8 No. The conclusion that Net Zero by 2045 would result in higher depreciation should be expected. A significant transformation of the energy industry -- as will occur to achieve Net Zero by 2045 – will result in a need to recover capital more quickly than in the past, as PG&E will need to invest in new technologies and as existing assets become obsolete more quickly. Investors in this energy transition are also likely to expect more rapid recovery of capital for both the deployment of new technologies and for the risk that existing assets will be retired or decommissioned as new technologies are developed and new functionality is required.

Q 9 How do the analyses you have provided in Table 12-7 of Chapter 12 of Exhibit (PG&E-10) inform the issues the Commission will need to consider in this GRC?

A 9 Given that these analyses support the need for higher depreciation, the most important question before the Commission is not necessarily determination of the precise life and net salvage estimates for each individual groups of assets. Instead, the most important question is how much of the needed increase in depreciation should occur during this GRC period. Other parties argue that we should delay and wait until more information is available. Cal Advocates and TURN even propose to decrease depreciation for electric and gas distribution assets. The other parties argue, for example, that we should wait until more decisions have been made in the Commission's ongoing rulemaking proceeding (R.20-01-007) established to "Establish Policies, Processes, and Rules to Ensure Safe and Reliable Gas Systems in California and Perform Long-Term Gas System Planning" (referred to in my testimony as the Gas Planning OIR).[7]

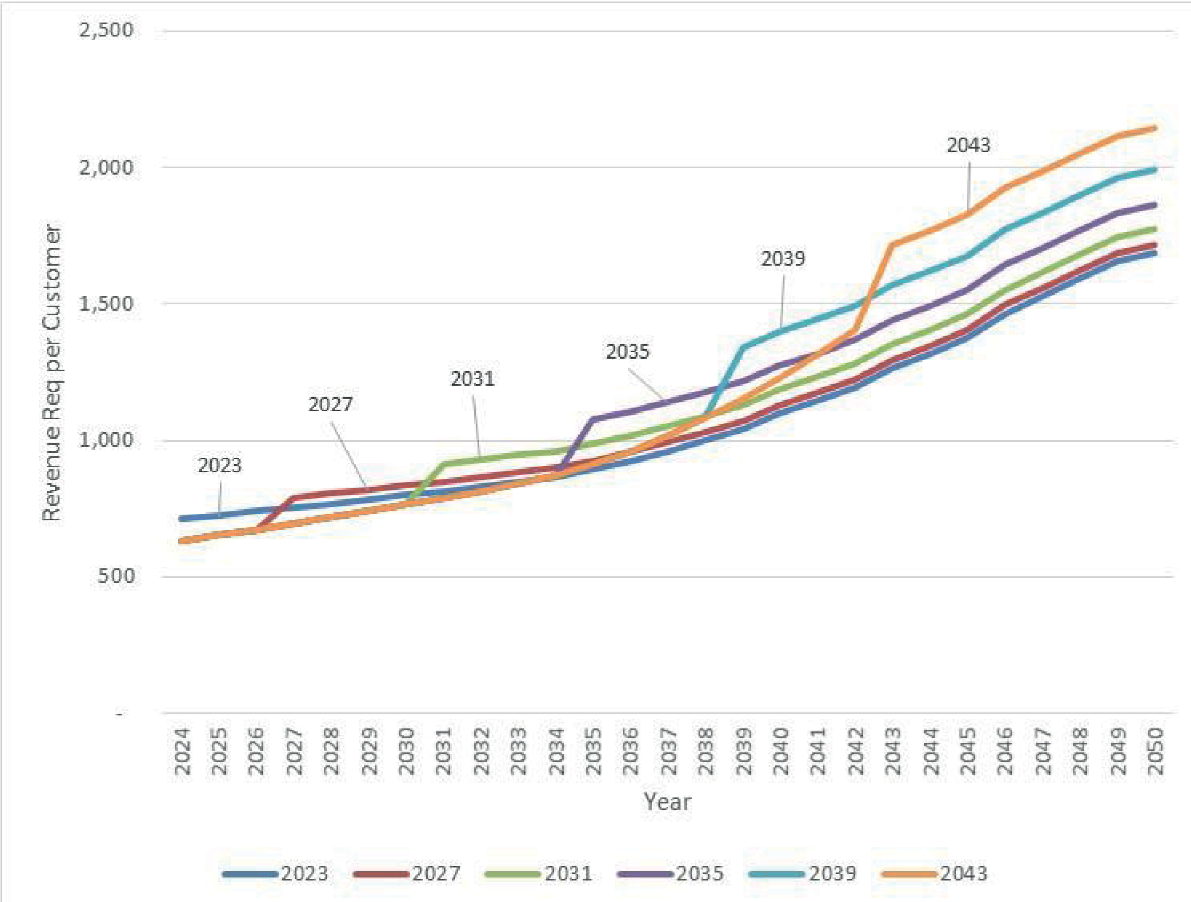
However, delay will not make these issues go away. Instead, it is likely to make them even more challenging. In my view, based on my experience

[7] See Exhibit CA-15, p. 25, lines 4-9; Exhibit TURN-18, p. 100, line 15 to p. 101, line 4; and Exhibit IS/NCGC-1, p. 9, lines 9-15.

performing depreciation studies for utilities across the country as well as my experience working on depreciation issues related to long-term GHG goals for utilities that operate in states with similar goals to California's, deferring any consideration of these issues to a future proceeding will only put off the inevitable and will make the energy transition more difficult. Delaying increases in depreciation has significant costs to customers.

Figure 12-1 below shows the overall gas distribution cost increase per customer that will be needed depending on the future GRC in which higher depreciation is recognized and incorporated into customer rates. As can be seen in the figure, the increase for the 2027 GRC line is more significant than the 2023 GRC line and remains higher each year thereafter. Similarly, the lines for later GRCs, such as the 2031 or 2035 GRCs, show even sharper increases. Thus, the figure demonstrates that the longer the Commission waits, the larger the needed increase. Delay will also make energy significantly more expensive in the future, both because of the direct impacts on natural gas rates but also because it will be more costly to make effective use of the state's valuable pipeline infrastructure. Indeed, delaying increases in depreciation too long risks derailing the most effective pathways to Net Zero by 2045 and making gas distribution infrastructure – which will still be needed in a Net Zero by 2045 world – prohibitively expensive.

FIGURE 12-1
REVENUE REQUIREMENT PER CUSTOMER BASED ON DATE OF IMPLEMENTATION OF UOP METHOD, 2023-2045



Q 10 Is PG&E's proposal consistent with the concept of gradualism, which has been discussed by the Commission in several cases related to depreciation?[8]

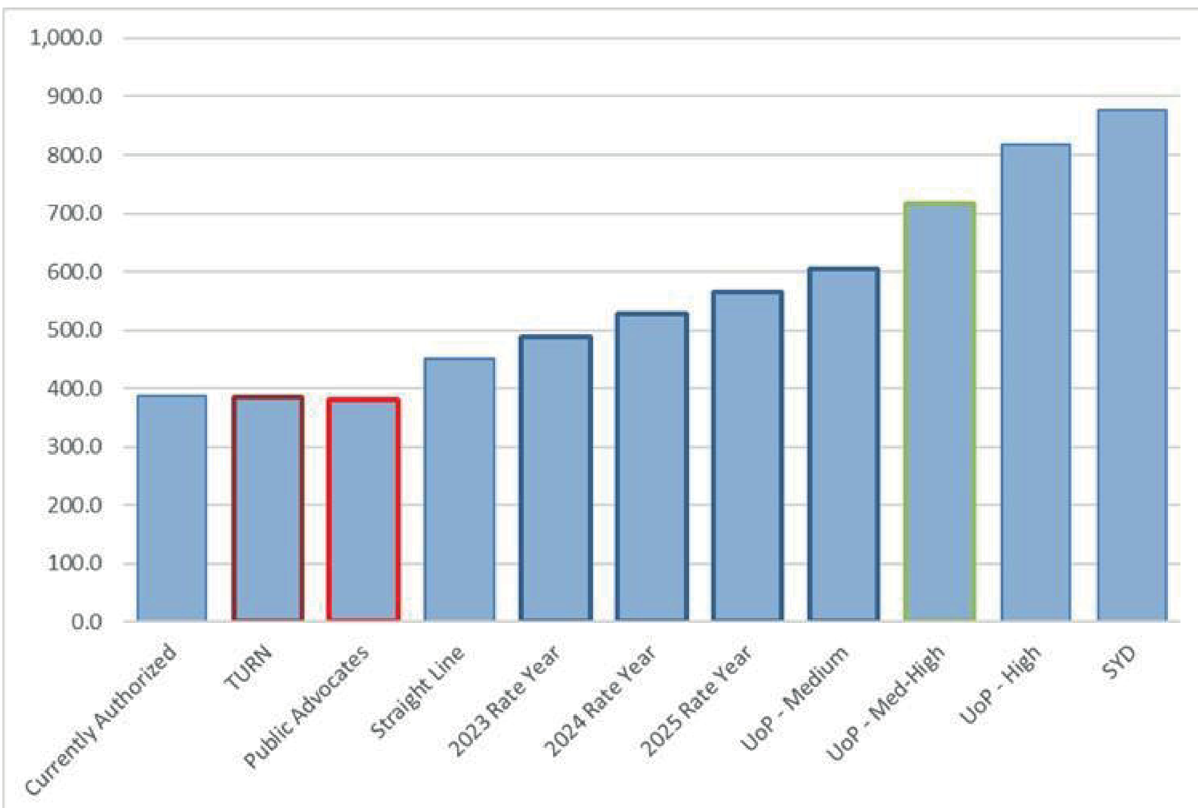
A 10 Yes, it is once we consider the magnitude of the potential impact of Net Zero by 2045. In Chapter 12 of Exhibit (PG&E-10), in Table 12-7. I presented the depreciation results under different scenarios of future gas demand. Figure 12-2 below shows the result of several of these scenarios. The bar highlighted in green is the scenario that, as discussed in Chapter 12A of Exhibit (PG&E-10), is based on a forecast of future gas demand for the next several decades that PG&E believes to be most likely. This is also the long-term scenario most consistent with the 2020 California Gas Report

---

8 See, for example, for PG&E, D.14-08-032, p. 11; and D.17-05-013, p. 106; and, for SCE, D.21-08-036, p. 674.

used for long-term planning.[9] PG&E's proposal is shown highlighted in blue. PG&E's proposal uses the more moderate Medium Electrification scenario an the proposed increase in depreciation for this GRC is phased in over four years. This proposal is, therefore, consistent with the concept of gradualism and considers the impact on current customers, as the increase is phased-in over four years and the end point once the phase-in is complete is still around $100 million less than results from PG&E's most likely Medium-High electrification scenario.

FIGURE 12-2
ANNUAL DEPRECIATION EXPENSE AS OF DECEMBER 31, 2020 BASED ON DEPRECIATION SCENARIOS AND PROPOSALS



I note that the most likely scenario -- the bar highlighted in green -- incorporates a decline in gas demand of approximately 69 percent by 2050, most of which occurs after 2035. Demand could decline more rapidly -- in which case the appropriate depreciation would be more similar

---

9 See Exhibit (PG&E-23), Ch. 12A for further discussion of the 2020 California Gas Report.

to the highest two bars in the graph above.[10] Thus, while the increases in depreciation are not insignificant, they are still gradual when compared to other possible scenarios.

As we can see in Figure 12-2, the transformation brought on by a Net Zero by 2045 goal will have a substantial impact on the level of depreciation necessary to recover PG&E's costs. PG&E's proposal results in lower depreciation than several of the scenarios shown, including the scenario that most closely aligns with PG&E's expectations and the California Gas Report. PG&E's proposal is also phased in over four years. Each of these aspects are consistent with the concept of gradualism.

Q 11 What will the Commission have to decide regarding PG&E's depreciation proposal?

A 11 The Commission will need to decide whether PG&E's proposal balances the interests of current customers, shareholders, and future customers, as well as whether PG&E's proposal facilitates the investment needed to transition to a Net Zero by 2045 energy industry. If the Commission believes that gas demand will decline materially by 2045, then PG&E's proposal balances the interests of current and future customers because it is the most equitable proposal from a depreciation standpoint. Further, if demand will decline significantly, then Cal Advocates, TURN and IS/NCGC's proposals significantly favor current customers over future customers as their proposals will result in future customers paying a disproportionate share of the recovery of the costs of the Company's assets. The implication made by TURN and IS/NCGC[11] that shareholders have little risk if PG&E's depreciation proposal is adopted by the Commission is also incorrect. As can be seen in Figure 12-2 above, PG&E's depreciation proposal may very well be far too low, meaning that PG&E's proposal does not eliminate risk for shareholders.

Q 12 If the Commission believes a different future scenario to be more likely than PG&E's scenario, should it adopt Cal Advocates', TURN's or IS/NCGC's proposals?

---

[10] Indeed, demand could decline more rapidly and reach its nadir earlier, as California's Net Zero goals are to be achieved by 2045.

[11] See Exhibit TURN-18, p. 101, lines 5-18 and Exhibit IS/NCGC-1, p. 12, lines 1-6.

A 12 No. The only way their proposals would be reasonable would be if the Commission believes that Net Zero by 2045 will have no impact on PG&E's gas system. Given that the Commission has noted a potential decline in the demand for natural gas and the need to minimize stranded costs,[12] it is doubtful the Commission believes there will be no impact on the gas system. That said, I recognize that the Commission may have a different outlook on the exact future of the gas industry in California than PG&E. If so, the Commission should adopt a level of depreciation that aligns with this outlook. It should not adopt the proposals of Cal Advocates or TURN, which are clearly incorrect because they incorporate no consideration of the future of the gas industry. Regardless of whether the Commission agrees with PG&E's outlook or has different expectations, California's Net Zero by 2045 goals mean that the future will be very different from the past and these differences need to be reflected in the Company's authorized depreciation rates.

Q 13 In developing its proposal, has PG&E considered the impacts on future customers?

A 13 Yes, as evidenced by both the use of a more moderate forecast and a four-year phase in. I recognize that the increase in depreciation proposed by PG&E is not small. However, the issues before the Commission are daunting and, in many ways, unprecedented. No modern society has been carbon neutral since the industrial revolution. Many of the technologies that will enable this energy transition do not exist today. Companies will need to innovate and put capital into new technologies. As I have worked on this issue for many utilities across the country, I firmly believe that -- due at least in part to utilities' concerns about affordability -- no utility has proposed depreciation of the magnitude that fully matches the impact of this energy transition. I believe this is also true for PG&E's proposal.

Further, while this is certainly true for the gas industry, it is also true for the electric industry. Indeed, in the time since I completed the depreciation study, the Company has announced a significant undergrounding program

---

12 *Order Instituting Rulemaking (OIR) to Establish Policies, Processes, and Rules to Ensure Safe and Reliable Gas Systems in California and Perform Long-Term Gas System Planning* (*Gas Planning OIR*), R.20-01-007 (Jan. 27, 2020), p. 13.

that will result in shorter lives for many current assets. Accordingly, with what we know today I think it is likely that, if anything, my average service life estimates for poles, overhead conductors and overhead transformers are too long.[13]

Ensuring the ability for a utility to raise capital is one of the goals of effective regulation.[14] Without it, the engineering marvel of our electric, gas and water systems would not have been able to be built and cannot be maintained and modernized. A change of the magnitude needed to achieve carbon neutrality in just over two decades is going to require significant investments in our energy infrastructure. Assets will be replaced or retired earlier than in the past and not all new technologies will succeed. The gas industry in 2045 will be significantly different from it is today, and possibly much smaller. Capital will need to be recovered faster than over the relatively long lives many assets have experienced historically,[15] both to allow for capital attraction and to send the proper price signals to the overall market.

PG&E has made a proposal that will accomplish this, in a manner we believe is equitable based on the best information available, and which also considers bill impacts for current customers. However, unlike the proposals of other parties, PG&E's proposal also recognizes affordability challenges for future, potentially captive customers. If the Commission declines to adopt PG&E's proposal, it should at a minimum adopt a realistic scenario that recognizes the impacts of transforming the energy industry to Net Zero by 2045. There should be little doubt that capital will need to be recovered faster than in the past. Failing to do so will only delay the inevitable, but with increased costs and much higher risks for both customers and investors.

---

13 I note here that both Public Advocates and TURN have proposed longer service lives than those currently in effect. This is indicative of the general lack of consideration of these issues by both parties.

14 See, for example, Bonbright, *Principles of Public Utility* Rates (2018), pp. 203-204.

15 Many gas assets have service lives of 50 years or more – more than double the time between now and 2045.

C. PG&E's Response to Parties' Depreciation Proposals

1. Positions of the Parties

a. Introduction

Q 14 Please summarize your response to the other parties who address depreciation issues.

A 14 There are two primary differences between PG&E's proposal and the other depreciation proposals in this case. The first is related to PG&E's proposal to use the UoP Method for gas distribution assets. The second is related to the more common depreciation issues in PG&E's recent GRCs – the service life and net salvage estimates for various asset classes. For both sets of issues, the primary difference between the parties to this case is that PG&E's proposals incorporate reasonable expectations about the future, whereas Cal Advocates, TURN and the IS/NCGC's positions do not (and, indeed, they do not even attempt to do so). The energy industry in California is beginning a major transformation to achieve Net Zero by 2045, which will have a profound impact on both gas and electric systems. These factors need to be considered when determining depreciation, as failing to do so not only risks shifting significant costs to future customers but also risks that the overall energy transition will not succeed due to challenges of raising capital and inaccurate price signals related to the cost of energy.

Rather than incorporate these factors, TURN and Cal Advocates' proposals are instead based primarily, if not entirely, based on the experience of the Company's assets in the past and do not give sufficient consideration of how the electric and gas industries of the future will be different from the past. Similarly, proposals by these parties and IS/NCGC to defer any recognition of the need for higher depreciation for gas assets to recognize the impact of declining gas consumption on future gas rates.

Q 15 Please explain these issues further.

A 15 As I have discussed earlier in this rebuttal testimony, there are several issues facing PG&E – and the electric and gas industries as a whole – that will have profound impacts on PG&E's system and its operations. These include state goals for significant reductions in GHG emissions as well as investments needed for safety and reliability, including hardening the system to be more resilient to wildfires. PG&E recognizes that its proposal to use the UoP Method for gas distribution assets is a relatively novel approach. However, the circumstances PG&E faces -- in which the Net Zero by 2045 goal is highly likely to result in reduced gas consumption, a decline in customers, or both -- are new and unprecedented in the industry. As I will discuss, the traditional approach to depreciation and the return of and on capital works well from a depreciation standpoint when demand is stable or increasing. However, when demand declines significantly, it has a pronounced effect on customer rates and raises serious concerns about both equity and future affordability.

PG&E believes its proposal, which incorporates the impacts of declining demand but also includes a more moderate forecast and a four-year phase-in, is the most equitable approach to deal with unprecedented ratemaking challenges that provides a proper balance between the need to recover costs of assets while they provide service to customers with affordability concerns. It is critically important that the Commission begin to address these issues as soon as possible – the longer we wait to address the impacts on gas depreciation the more expensive it will be to customers.

Q 16 Absent their disagreement with the use of the UoP Method at this time,[16] are there other serious issues with Cal Advocates and TURN's proposals?

A 16 Yes. While I can understand some hesitance to change to a different depreciation method such as UoP, both Cal Advocates and TURN's are unreasonable even absent the UoP issue. We know that the gas industry will be significantly affected by Net Zero by 2045 and that PG&E plans to upgrade or underground a significant portion of its overhead electric distribution system. Both of these factors are likely to result in shorter service lives for gas distribution and electric overhead distribution assets than has occurred in the past. TURN acknowledges that it believes lives for gas assets will be shorter in the future.[17] We certainly should not expect service lives for these types of assets to get longer. Yet, as shown in Table 12-1 above, both TURN and Cal Advocates have proposed to increase the

16 See CA-15, p. 24, and TURN-18, Appendix D.

17 See TURN's responses to PG&E's Data Requests PGE_TURN006-Q07, and PGE_TURN006-Q08 dated 6/27/22 in Appendix A, at the end of this exhibit.

service lives and reduce depreciation for gas distribution and electric overhead distribution accounts. In my judgment, not only are their proposals unreasonable, but they also demonstrate an inability to even contemplate the challenging issues PG&E currently faces. Stated differently, neither Cal Advocates nor TURN have made a proposal that attempts to equitably address what will happen over the next several decades or considers affordability issues for future customers in the context of declining gas demand.

Q 17 Does a depreciation study need to consider long-term impacts of what will occur over several decades?

A 17 Yes. The estimation of service lives and net salvage for property that has historically experienced service lives of 40 years or more necessarily means making a forecast about what will occur over several decades in the future. As a result, when determining depreciation rates, one must consider what will happen for several decades in the future.

Q 18 How will you address the proposals of other parties?

A 18 Before discussing the specific proposals, I would like to discuss several important depreciation concepts, considerations related to the gas industry, and provide context related to the proposed and authorized depreciation in previous GRCs. I believe these concepts and this context help to demonstrate why depreciation should be increased in this GRC at the level proposed by PG&E. I then address the UoP Method for gas assets and the importance of recognizing the realities of Net Zero by 2045 in depreciation. Finally, I discuss the service life and net salvage estimates made by Cal Advocates and TURN and explain the problems with their individual proposals. I also provide a separate discussion of PG&E's software lives, a portion of which is sponsored by PG&E witness Ajay Pathak.

b. Depreciation Concepts

Q 19 How is the concept of depreciation defined?

A 19 The Federal Energy Regulatory Commission's Uniform System of Accounts Prescribed for Public Utilities and Licensees Subject to the Provisions of the Federal Power Act defines depreciation as follows:

> Depreciation, as applied to depreciable gas plant, means the loss in service value not restored by current maintenance, incurred in

> connection with the consumption or prospective retirement of gas plant in the course of service from causes which are known to be in current operation and against which the utility is not protected by insurance. Among the causes to be given consideration are wear and tear, decay, action of the elements, inadequacy, obsolescence, changes in the art, changes in demand and requirements of public authorities, and, in the case of natural gas companies, the exhaustion of natural resources.[18]

Standard Practice U-4 presents several similar definitions with similar causes to be considered.[19] The Uniform System of Accounts (USOA) and Standard Practice U-4, therefore, both specifically enumerate obsolescence, changes in demand, requirements of public authorities and the exhaustion of natural resources as factors that should be given consideration. Estimating the service life of an asset used to calculate depreciation is not and should not merely be an exercise of determining how long the asset could physically remain in service. Other factors, such as obsolescence, must also be considered. Accordingly, the impact of Net Zero by 2045 should be considered when establishing depreciation rates.

Q 20 The term "accelerated depreciation" has been used in several contexts.[20] Is the Company's proposal accelerated depreciation?

A 20 No, not precisely. The UoP Method allocates costs on a straight-line basis in proportion to the units produced or consumed rather than equally to each year of service. It is, therefore, not technically accelerated depreciation because the level of depreciation varies depending on whether production increases, decreases or stays the same.[21] However, in a situation in which production or consumption will decline significantly, the pattern of recovery using the UoP Method is accelerated when compared to the straight-line method.

Q 21 What is the precise meaning of "accelerated depreciation"?

---

18 18 C.F.R. § 201, Definition 12B. The electric definition is similar, although does not include the clause related to exhaustion of natural resources.

19 See Standard Practice U-4, p. 6.

20 See, for example, R.20-01-007, *Assigned Commissioner's Amended Scoping Memo and Ruling* (Oct. 14, 2021), p. 8; CA-15, p. 24; and TURN-18, p. 99.

21 I note that if production is constant each year then UoP is equivalent to the straight line method.

A 21 The term "accelerated depreciation" applies to the method used to calculate depreciation. For accelerated methods, depreciation is designed to be higher in the earlier years of an asset's life and lower in the later years. Accelerated depreciation contrasts with the straight line method, in which equal amounts are allocated to each year of service. The National Association of Regulatory Utility Commissioners (NARUC) defines accelerated methods of depreciation as follows:

> Depreciation methods are classified as "accelerated" if they result in higher depreciation accruals in the early years of service life as compared to the straight-line method.[22]

Of all of the scenarios shown in Table 12-7 of Exhibit (PG&E-10), the only one that is based on a purely accelerated method of depreciation is the "Sum-of-the-Years-Digits" method.[23] This scenario would result in considerably higher depreciation than the Company's proposal. The other scenarios shown are based on either the straight line method or the UoP method.

Q 22 Do other parties use the term accelerated depreciation correctly?

A 22 No. TURN, for example, cites to a recent decision in Massachusetts that addressed a utility proposal for shorter service lives due to decarbonization goals were. TURN refers to this proposal to reduce service lives as accelerated depreciation,[24] which is both incorrect and not consistent with the findings of the Massachusetts Department of Public Utilities (Mass. D.P.U.).[25]

Q 23 How does depreciation impact a utility company and its customers?

A 23 Depreciation is both an important and complicated concept because it affects utility accounting, and, as a result, both customer rates and earnings,

---

22 See National Association of Regulatory Utility Commissioners (NARUC), *Public Utility Depreciation Practices* (1996), p. 57.

23 See Exhibit (PG&E-10) (Feb. 28, 2022), p. 12-36. I note here that, at least for a single asset, the Sum-of-the-Years-Digits is equivalent to a UoP Method in which production declines in equal amounts each year to zero at the end of the life of the asset.

24 See TURN's response to PG&E's Data Request PGE_TURN006-Q17, dated 6/17/22 in Appendix A, at the end of this exhibit.

25 See*,* Final Order, Mass. D.P.U. 20-120 (Sept. 30, 2021), p. 226; 2021 WL 4552393 (Mass.D.P.U.), *113.

in more than one way. Testimonies of other parties often focus on only one aspect of depreciation, that depreciation is an expense incorporated into a utility's revenue requirement. However, depreciation is also an expense on the company's books and, as an expense, annual depreciation accruals are a reduction to a company's earnings. Depreciation, therefore, has an effect on both revenues and expenses. This is consistent with the concept of the "matching principle" used in accounting, which provides a requirement to recognize expenses on the income statement in the same period in which the related revenues are earned. *Depreciation Systems*, a widely cited depreciation text, explains the matching principle as:

> The matching principle requires that all revenues earned during a given time period be matched with all the expenses incurred in that same time period to produce these revenues.[26]

It follows from this principle that the depreciation of capital assets which have lives that extend beyond one year should be recognized over the useful lives of these assets. As noted by NARUC, a cost allocation concept for depreciation "satisfies the accounting principle of matching expense and revenues."[27]

From a ratemaking standpoint, depreciation impacts both the revenues from customers, as annual depreciation expense is part of the revenue requirement, and the expenses charged to a given year. If depreciation is such that the depreciation expense over the life of an asset recovers the full cost of the asset (which includes the cost to retire the asset at the end of its life), then customer rates established based on these depreciation accruals will provide a return of capital to utility investors who originally provided the capital to invest in the asset.

A related concept in utility ratemaking is "intergenerational equity," in which customers who receive the benefit of a utility asset should pay their fair share of the costs of the asset. If too much depreciation is reflected in the early years of an asset's life, then customers in the early years will pay a disproportionate share of the cost of the asset, while customers in later

---

[26] Wolf and Fitch, *Depreciation Systems* (1994), p. 5.

[27] See, NARUC, *Public Utility Depreciation Practices* (1996), p. 12.

years will pay less than their fair share. Conversely, if depreciation is too low in the earlier years, then the costs of the asset would be unfairly borne by a future generation of customers.

Q 24 Does the depreciation of assets that has been recorded in prior years also affect customer rates?

A 24 Yes. There is also an additional way depreciation affects both customer rates and a company's earnings. Accumulated depreciation, which is effectively a running total of depreciation that has occurred in the past, is a reduction to rate base. As a result, while higher depreciation will have a short-term impact of increasing the revenue requirement in a given year, its longer-term impact will be to reduce rate base and, in turn, the return on rate base. The converse is also true. Lower depreciation expense will have a short-term effect of reducing the revenue requirement but over the long-term will result in a higher rate base and a higher return on rate base. Thus, when considering the impact on customers due to depreciation, there are both short-term and long-term impacts to consider and often these impacts move in the opposite direction from one another.

This concept is explained by NARUC:

> The regulatory body prescribing depreciation rates is thus confronted with a decision which affects both short-run and long-run interests of the customer and the company. If a commission prescribes rates which yield depreciation accruals that are too low, the revenue requirement in the short run may be lower. But the requirements for income taxes and return may offset the apparent savings in depreciation expense, so service rates in the long run may be higher. <u>If depreciation rates are set so low that the revenue requirement fails to repay the capital invested in a group of property by the end of its service life, confiscation takes place or the unpaid cost remains in the rate base until amortized or expensed.</u> On the other hand, if the regulatory body establishes depreciation rates toward the upper end of the zone of reasonableness, rates for service will be higher in the short-run, but may be lower in the long-run.[28]

---

28 See, NARUC, *Public Utility Depreciation Practices* (1996), p. 23 (emphasis added). I note that I would be surprised if the word confiscation in the emphasized passage were chosen lightly, as this is a term used in court decisions when assessing constitutional issues related to utility regulation. If gas demand does decline significantly, the failure to provide a utility the opportunity to recover its prudently invested costs would raise issues of whether rates established with too low of depreciation would be just and reasonable.

Q 25 Does the determination of the appropriate depreciation rates involve the determination of whether a company's capital costs were prudent or reasonable?

A 25 No. It is important to recognize that depreciation represents the recovery of capital invested by the Company (*i.e.*, the original cost of plant in service less net salvage) in order to provide utility service. The original cost of assets recorded on the Company's books and recovered through depreciation is related to assets already in service, a large portion of which have been in service for many years. Further, while net salvage is a future cost that requires estimates of the costs to retire or replace the Company's current asset base, Cal Advocates' and TURN's net salvage proposals are justified based on gradualism rather than specific disagreements with the estimates I have made. In other words, there is not necessarily a dispute as to the overall the level of future net salvage, but rather the pace at which we should move the estimates to the proper level.

This means that, broadly speaking, there is not a disagreement of the total amount of capital to be recovered through depreciation expense. The question of depreciation in this case, and the disagreement between other parties and the Company related to depreciation, is the timing of the recovery of capital – not the amount to be recovered. Because the question is a matter of timing, this means that lower depreciation today means higher depreciation in the future and higher depreciation today means lower depreciation – and a lower rate base – in the future.

c. It is More Harmful to Customers for Depreciation to be Too Low than Too High

Q 26 Please address TURN witness Garrett's statement that from a public policy perspective, "regulators [should] ensure that assets are not depreciated before the end of their economic useful lives."[29]

A 26 From a conceptual basis, Mr. Garrett argues that it is important not to have too high of depreciation because he believes that too high of depreciation could encourage "economic inefficiency."[30] Putting aside for a moment the

---

29 TURN-18, p. 11, lines 5-6.

30 TURN-18, p. 10, line 20.

merits of Mr. Garrett's argument, it is highly unlikely that the depreciation proposals in this GRC will result in assets being depreciated before the end of their economic useful lives. It is also unlikely the Company's proposal results in "excessive" depreciation rates of which Mr. Garrett warns,[31] given that, as shown previously in Figure 12-2, depreciation would be higher than PG&E's proposal under several future gas demand scenarios.

However, even if one accepts Mr. Garrett's premise that too high of depreciation encourages economic inefficiency, then the converse would also be true. Too low of depreciation could encourage economic inefficiency by, for example, causing a disincentive for a company to invest in new technologies or replace aging, inefficient assets. As I have discussed previously in Section B.2, I am concerned that too low of depreciation could affect the Company's ability to raise capital, send improper price signals and disincentivize needed investments in new technologies and replacements of obsolete equipment.

Further, as I have discussed in my opening testimony,[32] the risks of too high of depreciation and too low of depreciation are asymmetric. That is, the potential harm from under-estimating depreciation is greater than the potential harm from over-estimation. If depreciation is too high, it can be reduced in future studies while the assets are still in service. However, if depreciation is too low and assets are retired prior to being recovered through depreciation, then future customers will have to pay for the costs of these assets after they are removed from service. Again, this risk is considerably greater as it relates to Net Zero by 2045 because the future customer base may to be smaller than the current customer base and there will be less time to equitably recover PG&E's costs.

Q 27 In your experience, is it more likely that assets will be retired prior to being fully depreciated than the opposite situation, in which assets are fully depreciated before the end of their service lives?

---

31 TURN-18, p. 9, lines 10-12.

32 See Exhibit (PG&E-10) (Feb. 28, 2022), p. 12-37, line 20 to p. 12-38, line 10.

A 27 Yes. The situation Mr. Garrett describes in his testimony[33] – in which an asset is fully depreciated before the end of its economic useful life – is less common than the opposite situation, in which an asset or group of assets are retired before becoming fully depreciated. In my experience, factors such as technological change and policy decisions have often led to retirements of assets earlier than expected. As result, in such situations there has been a need to recover a large portion of an asset's cost over a relatively short remaining life. For example, there have been many examples over the past decade of the combination of age, new generation technologies and regulatory policies resulting in electric generation facilities being retired earlier than had been expected. In jurisdictions in which electric generation is still included in rate base, this has meant that the costs of these assets have often had to be recovered after their retirement – with significant cost impacts to customers. Similarly, there have been other examples of new technologies causing existing assets to be obsolete, such as Advanced Metering Infrastructure ("AMI") technology resulting in the wholesale replacement of legacy electric meters. Examples of the sort Mr. Garrett fears, in which large assets or a group of assets becoming fully depreciated before the end of their useful lives, have been less common.

The examples of earlier than expected retirements are instructive as we consider how obsolescence will impact depreciation. In my experience, it has been more common to under-estimate the impact of obsolescence than to over-estimate its impact. In many ways, this is human nature – we expect that change will be gradual. But the future is difficult to predict and often change occurs faster than we expect. One only needs to consider how many technologies we use on a daily basis (the internet, smart phones, video meetings being examples) have only become widespread fairly recently to recognize that significant changes can occur quickly and that obsolescence can have a much greater impact than expected. We can also consider the legacy technologies that these new technologies have displaced, such as landline telephones and business travel, to understand how quickly obsolescence can occur.

---

33 TURN-18, p. 11, lines 1-6.

In other words, experience teaches that the assumption inherent to Cal Advocates', TURN's and IS/NCGC's depreciation proposals – that the future will be substantially similar to the past[34] – has often been incorrect. In many instances, obsolescence has had a broader and faster impact than many observers had assumed, and the pace of technological change has increased. It is very possible that the same will be true as it relates to Net Zero by 2045. But it is even more critical to account for obsolescence in depreciation in the context of Net Zero by 2045 because estimating too long of depreciable lives – i.e., failing to incorporate obsolescence – will result in the future, likely smaller, customer base bearing a disproportionate share of the costs of the Company's assets. There is little margin for error and there are far greater risks for both the Company and customers to estimating too low of depreciation than estimating too high of depreciation.

d. PG&E's Authorized Depreciation Rates Have Been Too Low for Several Rate Cases

Q 28 Cal Advocates, TURN and IS each note the increase in depreciation from the depreciation study.[35] Please provide context of PG&E's proposed and authorized depreciation rates in recent cases.

A 28 As I have discussed previously and will explain in more detail later in this testimony, California's Net Zero by 2045 goals mean we should expect depreciation to need to be higher than in the past. However, for several GRCs, PG&E's depreciation rates have been established at a level lower than supported by the Company's depreciation studies. Further, as I discuss in more detail in Section C.1.e, the primary reason for this has been decisions to gradually recognize increases in depreciation over several rate case cycles.[36] This may be reasonable for a policy standpoint, but

---

34 For further discussion, see Sections C.B.2, C.3.b and C.3.c of this rebuttal testimony. A

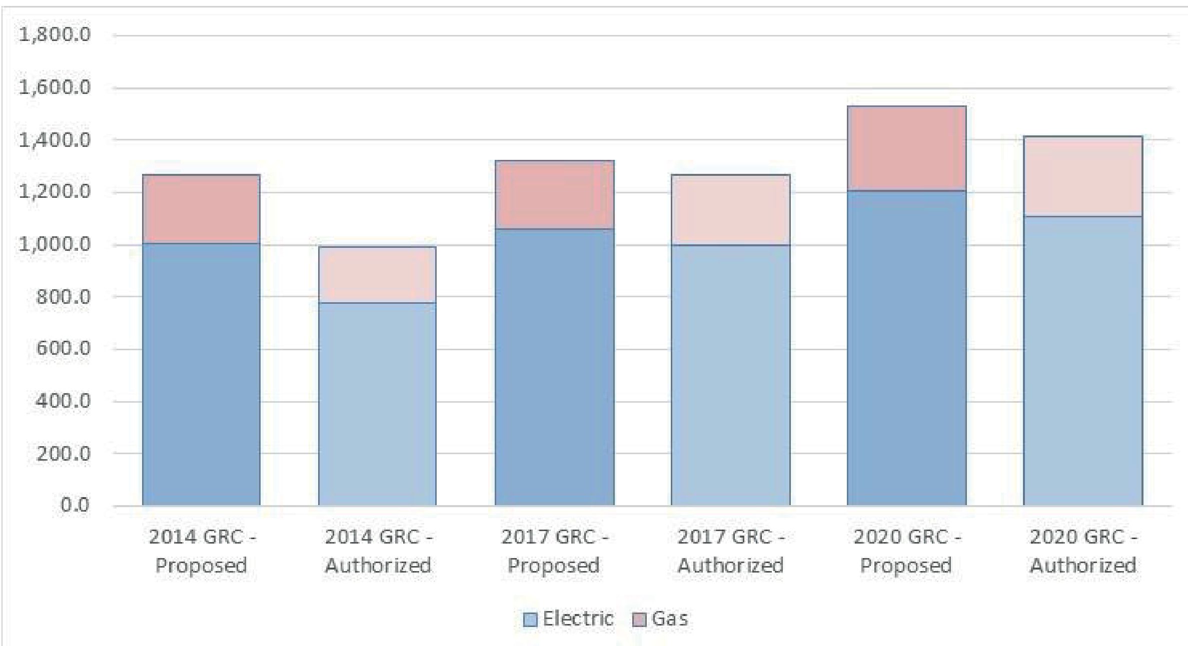
35 See, CA-15, p. 8, lines 19-20; TURN-18, p. 102, lines 2-5; and, IS/NCGC-1, p. 2, lines 2-4.

36 In particular, because the Company's proposed service lives for most accounts been incorporated into the depreciation rates authorized by the Commission (whether through the Commission's decision in the 2014 GRC or in settlements in the 2017 and 2020 GRCs), the lower depreciation rates authorized in each case have been due to more gradual changes in net salvage than the net salvage estimates in the Company's (already gradual) depreciation studies.

nevertheless means that depreciation is too low today and we should expect depreciation to need to increase.

Figure 12-3 below shows the proposed and authorized depreciation expense[37] in each of the last three GRCs. The bottom bars show electric depreciation expense and the top ones show gas depreciation expense. As the chart shows, depreciation in each of these GRCs was lower than PG&E's depreciation study.[38]

FIGURE 12-3
PROPOSED AND AUTHORIZED DEPRECIATION EXPENSE FOR ELECTRIC AND GAS PLANT IN SERVICE IN 2014, 2017 AND 2020 GRCS



The fact that authorized depreciation was lower than in PG&E's depreciation studies means we should expect an increase in depreciation expense for two reasons. First, accumulated depreciation is lower than it would have otherwise been had PG&E's depreciation study been adopted in total. This means depreciation will be higher, all else equal, because more

---

[37] These figures are based on the depreciation study test year rather than the GRC test year. So, e.g., the 2014 GRC amounts are based on 2011 balances.

[38] I note that the Company voluntarily reduced net salvage estimates in the 2011 GRC due to the impacts of the Great Recession, so the same concept holds for that GRC as well.

needs to be recovered over remaining lives of the Company's assets. Second, it also means that, in each successive case, we should expect an increase in depreciation to make up for the fact that the prior case established lower depreciation rates due to gradualism. The use of gradualism for net salvage estimates in previous cases to mitigate the impact on rates is a tacit recognition that net salvage should be more negative. Thus, depreciation should be expected to increase. We should, therefore, expect depreciation to increase in this GRC even absent the impact of Net Zero by 2045.

e. Gradualism

Q 29 What is the concept of gradualism as it pertains to depreciation?

A 29 The concept of gradualism generally refers to making smaller, or gradual, changes to depreciation parameters as opposed to making large changes in a single study. The concept has been used to refer both to changes in parameters as well as to the overall impact on depreciation expense.

In D.14-08-032 in PG&E's 2014 GRC, the Commission defined gradualism as follows:

> The principal of gradualism applies where there is a recognized need to revise estimated parameters, but where the change is allowed to occur incrementally over time rather than all at once. Applying gradualism thus limits the approved increase that would otherwise be warranted, all else being equal, and mitigates the short-term impact of large changes in depreciation parameters. Also, it is advisable to be cautious in making large changes in estimates of service lives and net salvage for property that will be in service for many decades, as future experience may show the current estimates to be incorrect.[39]

There are actually two distinct concepts of gradualism in the Commission's definition above. The first is related to how changes to service lives and net salvage impact depreciation expense and the resultant impact on customer rates. The second concept is related to an aspect of gradualism which focuses on individual parameter changes from one depreciation study to the next. This second concept of gradualism is well understood among depreciation professionals and focuses on the fact that depreciation studies consist of statistical analyses of a great amount of data

---

[39] D.14-08-032, p. 598.

and the exercise of professional judgment. Changes in service life and net salvage estimates may be made gradually to not overreact to trends in the data and to ensure that over time depreciation is approached in a systematic and rational manner.

Because each rate case in California has included data from an additional three years, as compared to the great number of years' data previously existing, the depreciation professional's recommendations may often change gradually and not abruptly from one depreciation study to the next. Stated otherwise, one would not expect a statistical analysis to change dramatically based on adding three years to an existing historical data base spanning 40 years or longer.

Q 30 Has the Commission also discussed that gradualism applies to service life and net salvage estimates, not only rate impacts?

A 30 Yes, In Appendix E-2 to D.14-08-032 (PG&E's 2014 GRC) the Commission discussed this concept of gradualism as it applied to service life estimates. Appendix E-2 addressed TURN's efforts to extend service lives and rejected TURN's proposals on account of gradualism (and other factors) *even though the changes would have reduced rates*.[40] Thus, it should be clear that the Commission intended gradualism to refer to service lives, as well as net salvage and that gradualism should be applied consistently.

Q 31 Are there any exceptions to the concept gradualism?

A 31 Yes, gradualism is not a concept that should necessarily have universal use. If, for example, we expect the future to materially different from the past (and particularly if this change were fairly abrupt, such as through landmark legislation or regulation), then there is less of an argument for being gradual. At a minimum, gradualism should be considered in the context of the needed change – a $1 million increase is gradual if the appropriate level of depreciation is, perhaps, $2 million greater, but is not gradual if depreciation should be $100 million greater.

Q 32 In your judgment, is PG&E's proposal consistent with the concept of gradualism?

A 32 Yes.

---

40 See D.14-08-032, Appendix E-2, pp. 2, 3; 5; and 7.

Q 33 Are Cal Advocates and TURN's proposals consistent with the concept of gradualism?

A 33 No. Neither parties are gradual changes when compared to the overall scope of the needed increase in depreciation. Indeed, both propose decreases in depreciation for electric and gas distribution assets, which rather than incorporating gradualism moves depreciation in the opposite direction. Further, as I will discuss in more detail in Sections C.3 and C.4, both parties apply the concept inconsistently and appear to only consider gradualism when changes in parameters would increase depreciation.

2. Units of Production Method

a. The UoP Method is the Most Equitable Method When Consumption Declines

Q 34 Please explain why PG&E proposes the UoP Method for gas distribution assets.[41]

A 34 PG&E, as well as gas utilities in other states with similar greenhouse gas reduction goals, face a unique challenge from a cost recovery and ratemaking standpoint due to unprecedented changes to the industry. Achieving net zero carbon emissions is likely to mean that less gas (whether natural gas or lower emission alternatives) will be used in 2045 than is currently used today. From a depreciation standpoint, costs are typically allocated to each year of service using the straight-line method, in which equal amounts are allocated to each year of service. From a conceptual standpoint, in most circumstances this achieves the goals of intergenerational equity and the matching principle. Utility assets provide a similar level of service over their useful lives and the straight line method, therefore, allocates costs in a manner consistent with the usage of a Company's assets. The recovery of costs effectively approximates the service provided in each year by the Company's assets. In normal circumstances, therefore, straight-line depreciation is widely considered to result in intergenerational equity.

Q 35 Is this true if demand declines significantly?

[41] See Exhibit (PG&E-10) (Feb. 28, 2022), p. 12-28, line 1 to p. 12-39, line 5.

A 35 No. If demand is much lower in the later years of an asset's life than in the early years, then the straight-line method does not allocate costs in a manner that approximates the service provided by the asset. Customers at the end of the asset's life will, therefore, have to pay a higher per-unit share of the capital costs of providing their service than those early in the life of the asset. If the decline in the number of customers is commensurate with the decline in demand, then this means customers at the end of the asset's life would pay a disproportionate share of the costs of the asset.

The straight line method also results in issues from an accounting standpoint if demand declines. Revenues decline as demand declines, but expenses remain constant, making it more difficult for revenues to cover expenses in the later years. This means that when demand declines significantly -- and the straight line method does not match revenues and expenses -- the wrong information and price signals are sent to both customers and markets.

This is true in general if depreciation is too low, resulting in expenses artificially low when compared to needed revenues. The lower price disguises that prices will have to rise significantly in the future to cover expenses. Further, if depreciation is too low, then financial statements do not sufficiently recognize that expenses will significantly rise in the future, giving improper information to investors.

Q 36 Given these considerations, is it important that depreciation recognize the potential for significant declines in demand?

A 36 Yes. PG&E's proposal to use the UoP Method addresses this issue by allocating costs in proportion to the utilization of the assets, rather than in equal amounts each year.

Q 37 By matching the allocation of costs to gas throughput, does the UoP Method have any additional advantages if throughput declines?

A 37 Yes. The UoP Method will provide a more equitable allocation of costs if throughput declines regardless of the reason for the decline. The future of the gas industry could have declining throughput due to a decline in the number of customers or due to a decline in usage on a per-customer basis (or both).[42] Adjusting only service lives and net salvage while using the straight-line method does not account for the impact of a decline in demand on a per-customer basis and will result in larger increases in the future on a per-unit basis.

Q 38 One of IS/NCGC witness Brubaker's arguments against the UoP Method is that there is not a precedent for using it for "delivery system assets of natural gas distribution companies."[43] Please address his argument.

A 38 Mr. Brubaker's comment is both technically correct and also misses the point. There is no example of the use of the UoP method for gas delivery systems because PG&E's situation is unprecedented. We should expect to need different approaches to address the impact of as major a change as Net Zero by 2045. The Commission has recognized this in its order initiating the Gas Planning OIR.[44]

I will concede that there was little reason to use UoP for most of the gas delivery business's existence, which dates to before the Civil War. But the current set of issues the industry faces is fundamentally different. There is no precedent for using the UoP Method for gas distribution assets because until very recently there had not been a situation in which the UoP Method would be most appropriate for gas distribution assets. This is no longer true, and, for the reasons I discuss in my testimony,[45] the UoP Method is now most appropriate for PG&E's gas assets and, from a depreciation standpoint, is the method I believe best addresses the capital recovery issues currently facing the gas industry.

Q 39 Both TURN and IS/NCGC argue that the risks of stranded costs should be shared by shareholders and ratepayers, with the implication that your proposal does not do so.[46] Do you agree?

---

42 For example, customers could opt to not use gas for primary heating but still use gas for cooking and, possibly, as a backup fuel for heat. This would cause demand to decline even if the number of customers remains relatively constant.

43 See, IS/NCGC-1, p. 11.

44 *Gas Planning OIR*, R.20-01-007 (Jan. 27, 2020), p. 13.

45 See Exhibit (PG&E-10) (Feb. 28, 2022), beginning on p. 12-28, line 28.

46 TURN-18, p. 101, lines 5-18, and IS/NCGC-1, p. 12, lines 1-6.

A 39 No. First, the concept that investors do not share risk if PG&E's proposal were adopted is incorrect. PG&E's proposal is based on a recovery of costs consistent with a decline in gas demand of approximately 55% by 2050 and most of this occurs after 2035. Gas demand could decline considerably more than this and could do so sooner. It could, for example, decline by 80 or 90% by 2045. TURN and IS/NCGC's arguments are based on an implicit assumption that PG&E's depreciation proposal is certain to result in too high of depreciation. But the opposite is true. PG&E's proposal considers several future gas throughput scenarios. It is not the proposal with the highest level of throughput decline. Indeed, while PG&E believes the Medium-High E3 scenario is most probable, [47] its proposal actually results in less depreciation than would result from PG&E's the Medium-High scenario. Indeed, there are several scenarios under which it would be most appropriate to have higher depreciation. Investors, therefore, bear risk with PG&E's proposal.

Second, the logical extension of TURN and IS/NCGC's argument appears to be that any increase in depreciation will unfairly favor investors. However, their argument does not properly consider how depreciation impacts current and future customers as well as investors. Depreciation should be established in an effort to most equitably match cost recovery with consumption of the assets, based on the information available today. Current customers are not unfairly burdened by setting depreciation at the proper level even if it means higher depreciation today. However, future customers are unfairly burdened if current depreciation is established at a level that is too low.

Finally, TURN and IS/NCGC's proposal, which as I have discussed is effectively to assume Net Zero by 2045 will have no impact on the gas system, puts almost all of the risk on shareholders and future customers. It is not balanced but rather uses the extreme low-end of possible future scenarios. In doing so, both parties fail to balance the interest of current and future customers, favoring today's customers over those that will continue to need gas in the future.

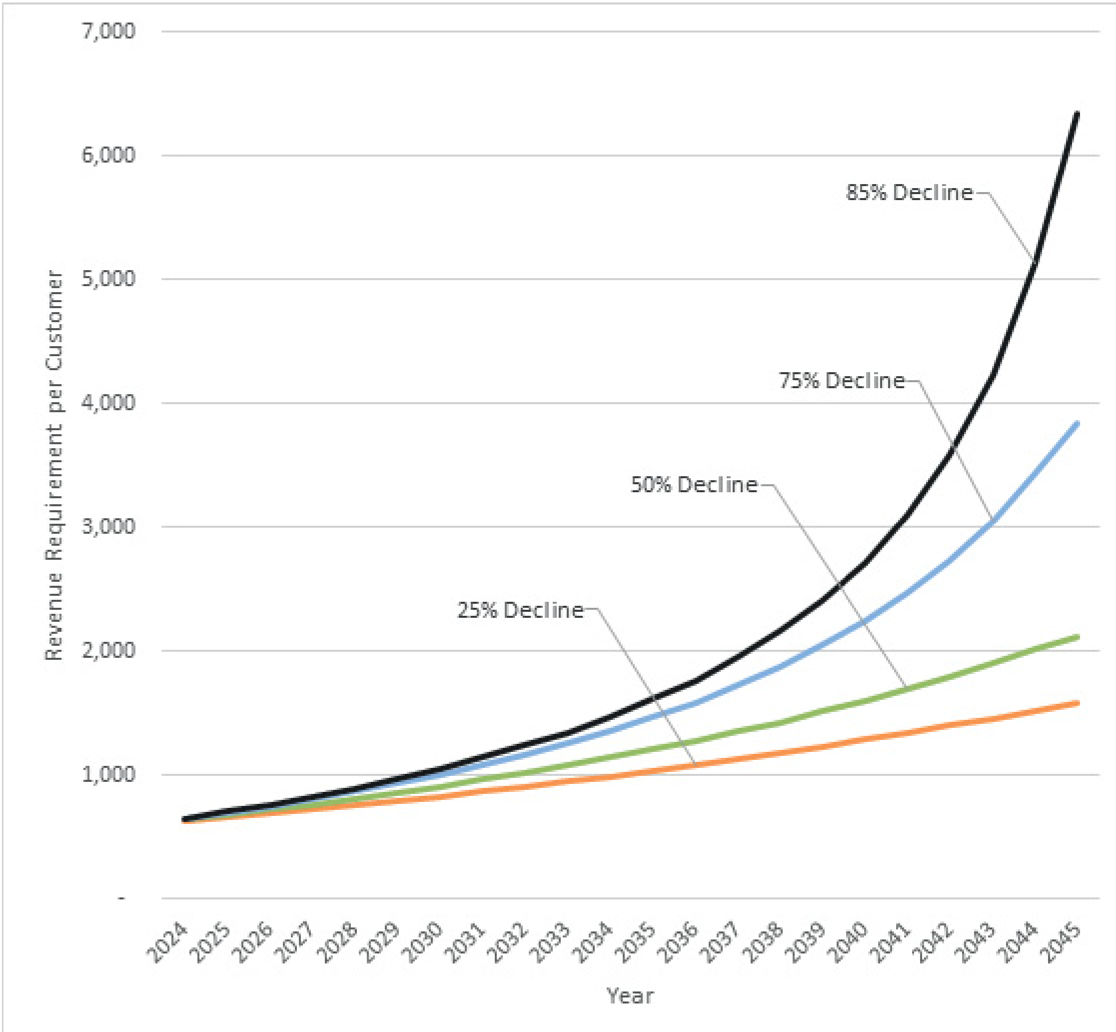
---

[47] See Exhibit (PG&E-10) (Feb. 28, 2022), p. 12A-5.

Q 40 To help demonstrate that your proposal considers both current and future customers, please provide an example illustrating the impact of declining demand on customer bills.

A 40 Figure 12-4 below provides the impact of the use of straight-line depreciation on the revenue requirement per customer from 2023 through 2050 under different scenarios of declining demand and customers. The scenarios shown model the revenue requirement per customer based on declines in gas demand, and commensurate declines in customers, of 25 percent, 50 percent, 75 percent and 85 percent. As the chart shows, the steeper the decline in demand the greater the rate impact on the remaining customers. If demand declines rapidly, bills will need to increase significantly in order to recover the remaining costs over a smaller number of customers.

FIGURE 12-4
REVENUE REQUIREMENT PER CUSTOMER USING STRAIGHT LINE DEPRECIATION BASED ON DECLINES IN GAS DEMAND OF 25%, 50%, 75% AND 85%



Q 41 How does the UoP Method address this issue?

A 41 The UoP Method, as proposed for PG&E, allocates depreciation in proportion to gas throughput.[48] When demand declines, this allows depreciation to remain more consistent on a per unit basis. As a result, there is not the same steep increase on a per customer basis as if straight- line depreciation is used. Accordingly, in an unprecedented situation such as the decline in demand due to achieving Net Zero by 2045 goals, the UoP Method is more equitable and better balances the impacts on both current and future ratepayers.

b. Gas Depreciation Considerations with Forecasts of Declining Demand

Q 42 IS/NCGC witness Brubaker discusses the E3 Forecast, which was described in more detail in Chapter 12A of Exhibit (PG&E-10).[49] How was this forecast considered when determining PG&E's depreciation proposal?

A 42 PG&E witness David Sawaya describes the development of the forecast and considerations that led to PG&E's conclusions regarding which scenario is most likely in more detail in Chapter 12A of Exhibit (PG&E-10). PG&E engaged E3 to develop forecasts of what PG&E's gas system might look like in the future, particularly as it relates to gas demand for the next thirty years. Additionally, PG&E incorporated the California Gas Report forecast into its analysis. I have reviewed these forecasts as well as considered analyses I have performed for other utilities facing similar issues. I have not seen any reason to doubt the E3 forecasts can be used to determine depreciation rates based on the UoP Method.

Q 43 Given capital recovery issues facing PG&E's gas business in California, how did you approach the depreciation study?

A 43 As I began working on the depreciation study, PG&E and I discussed the appropriate approach to depreciation if demand were to decline significantly. I explained that, at the time, I had started to see intervening parties in New

---

48 See Exhibit (PG&E-10) (Feb. 28, 2022), p. 12-28 to p.12-32.

49 IS/NCGC-1, pp. 4-7.

York[50] argue for higher depreciation than I had proposed in depreciation studies due to greenhouse gas emission legislation and that my understanding was that other states had begun to consider the impacts on depreciation. PG&E and I also discussed that the UoP Method, while not frequently used for regulated electric or gas distribution companies, was an accepted approach and based on a principle of matching depreciation with utilization (whether that is production or consumption). Further, we discussed that if demand declines or increases rapidly, then UoP may better matching expenses and revenues from a depreciation standpoint. I also explained that UoP was used in other industries, such as freight rail, mining, and that there has been a long established precedent before FERC and other regulators of using UoP for resource producing industries (e.g., gas production and gathering).

Q 44 What was the conclusion of this process?

A 44 The conclusion was that, given the potential system-wide impacts, UoP was the most appropriate method to use for gas distribution assets. Further, PG&E concluded that using the medium-high E3 forecast for the UoP Method produced the most equitable allocation of costs from a depreciation standpoint, given the information available at the time.[51] However, PG&E also recognized that a change to the UoP Method would result in significant increases in depreciation and proportionate increases in customer bills. Based on these considerations PG&E opted to use a more moderate forecast, the Medium Electrification E3 scenario, and phase in the impact over the four rate years as a means to mitigate bill impacts from necessary increases to depreciation.[52]

Q 45 Have you calculated depreciation using different E3 scenarios?

A 45 Yes. In Table 12-7 of Chapter 12 of Exhibit (PG&E-10), I provided several different depreciation scenarios for gas assets. These were based on E3 scenarios of projected gas demand under varying degrees of electrification. I have provided the several of the E3 forecasts, as well as a comparison the

---

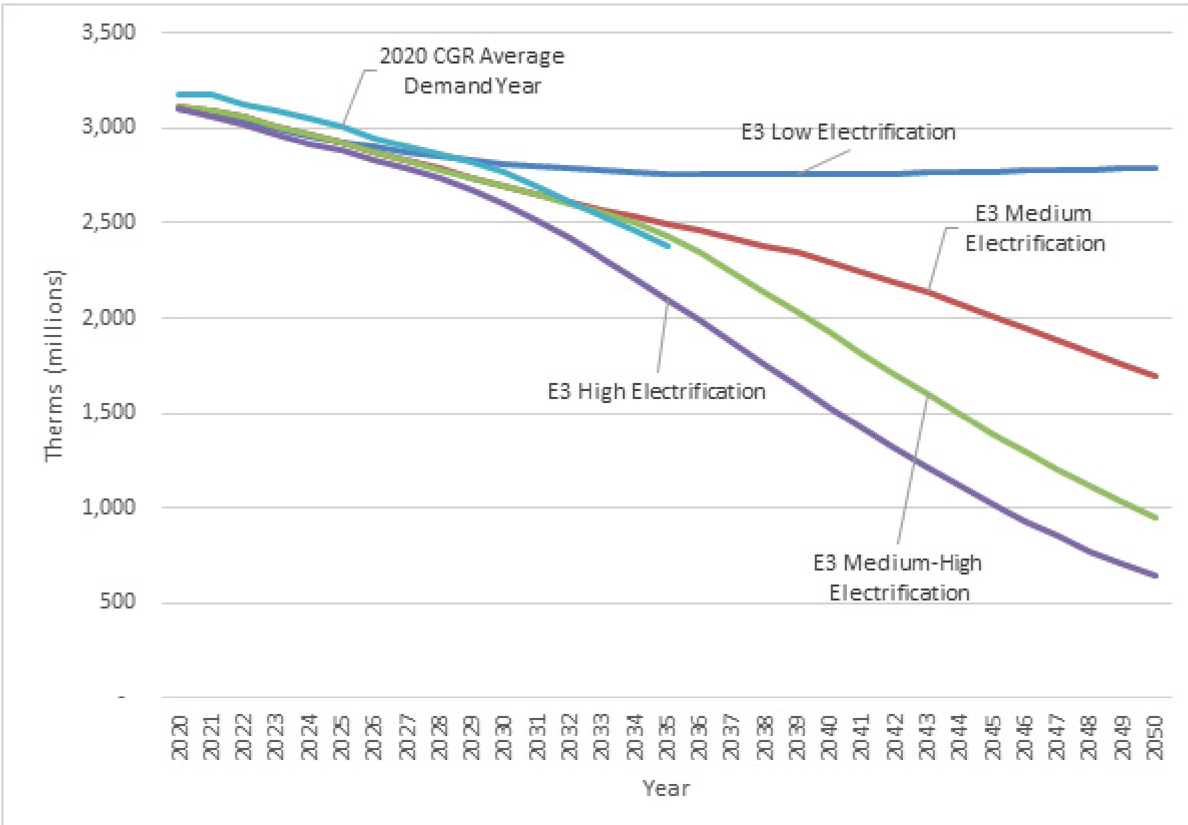
50 See, for example, New York Pub. Svc. Commission (PSC), Docket No. 19-G-0066 (Mar. 13, 2019), testimony of Robert Wyman, (as of July 7, 2022).

51 See Exhibit (PG&E-10) (Feb. 28, 2022), Ch. 12A.

52 See Exhibit (PG&E-10) (Feb. 28, 2022), p. 11-27, lines 3-25.

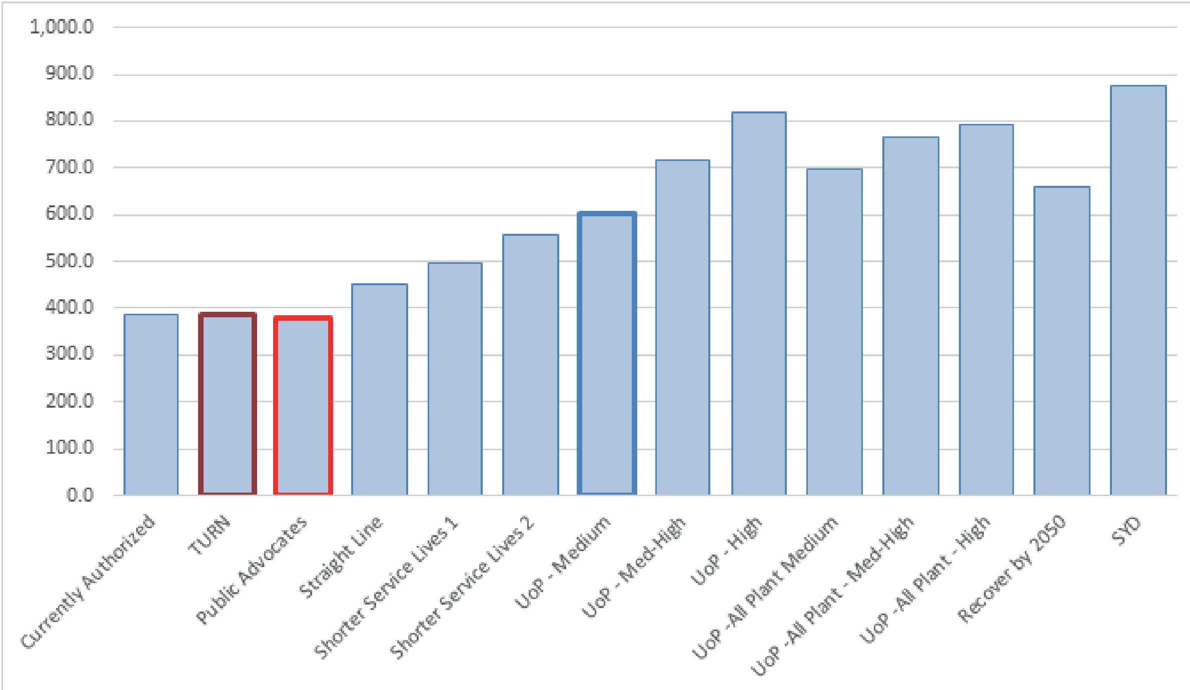
2020 California Gas Report forecast (which only extends to 2035), in Figure 12-5 below.

FIGURE 12-5
E3 AND CALIFORNIA GAS REPORT FORECASTS OF PG&E GAS THROUGHPUT



In Chapter 12 of (Exhibit PG&E-10) I provided the results of the UoP Method incorporating these scenarios. These included incorporating UoP for all gas assets as well as scenarios solely focused on gas distribution plant. Figure 12-6 below provides a graph comparing the depreciation resulting from these E3 scenarios of the depreciation study year of 2020. Also included is an accelerated depreciation scenario in which demand effectively declines to zero.

FIGURE 12-6
COMPARISON OF DEPRECIATION PROPOSALS WITH DEPRECIATION SCENARIOS BASED ON E3 GAS FORECASTS



As the figure shows, depending on which scenario unfolds, there is a wide range of depreciation results that would be most equitable. For example, the E3 Medium-High scenario produces depreciation expense as of December 31, 2020 of approximately $716 million. The Medium-High forecast is most consistent with the California Gas Report and PG&E's long-term expectations discussed in Chapter 12A of Exhibit (PG&E-10). However, if a higher electrification scenario were used, then depreciation should be more than $800 million.

Q 46 What are some of the considerations the Commission can learn from this analysis?

A 46 A comparison of these different scenarios and proposals demonstrates several important points. First, while there is a range of possible outcomes depending on the precise path forward for the gas industry, PG&E's proposal is not at either extreme end of the range. As can be seen in Figure 12-6 above, the currently authorized depreciation is somewhat below $400 million, whereas the high electrification scenario would produce depreciation expense of more than $800 million. PG&E's proposal results in depreciation expense of close to $600 million and is, therefore, close to the middle of this range. Second, as discussed in Chapter 12A of Exhibit (PG&E-10), PG&E's use of the medium forecast, rather than the Medium-High scenario that PG&E believes is most likely, means that PG&E's proposal is more moderate than the most likely scenario – which would result in depreciation expense in an amount greater than $700 million – close to $100 million more than PG&E's proposal. Finally, PG&E's proposal is to phase in the increase in depreciation over four years. Given all of these considerations, PG&E's proposal does – contrary to the claims of other parties – balance the reality of the need for higher depreciation with impacts on current customers, as well as the risks to both future ratepayers and shareholders.

Q 47 Do Cal Advocates' and TURN's proposals balance the impacts of current customers, future customers, and shareholders?

A 47 No. In sharp contrast to PG&E's proposal are the results of Public Advocates' and TURN's proposals. As the graph above shows, both parties propose depreciation that is even lower than the currently authorized level of depreciation. Their proposals are, therefore below even the extreme low end of potential scenarios. Their proposals are entirely unrealistic given the information available today. While reasonable people may disagree on the precise amount throughput may decline and depreciation needs to increase, we should be quite certain that depreciation will need to increase as capital needs to be recovered more rapidly for gas assets than in the past due to the transition to net zero carbon emissions.

c. Delaying Implementing Needed Increases to Depreciation will be Costly

Q 48 In your work on the issue of decarbonization and the gas industry, have you analyzed the future rate impacts of different depreciation scenarios?

A 48 Yes. In addition to my work with PG&E, this includes several depreciation studies,[53] a white paper authored with Gannett Fleming colleagues in

---

53 See, for example, my direct testimony in Mass. D.P.U. 20-120; special depreciation studies in New York PSC, Docket No. 19-G-0379 (Mar. 15, 2022); and the direct and rebuttal testimonies of the Depreciation Panel in New York PSC, Docket No. 22-G-0065.

2021,[54] as well as several presentations on the topic to industry groups over the past few years. As I, my colleagues at Gannett Fleming, and our clients have analyzed the impacts of decarbonization, we have observed that delaying recognizing higher depreciation can be very costly to customers in the long run.

Q 49 Can you provide an example showing how deferring implementation of the UoP Method might play out for PG&E and its customers?

A 49 Yes. Let us consider what would occur if gas demand does follow the E3 Medium-High forecast through 2045.[55] To illustrate the potential impact depreciation and rates, my team at Gannett Fleming has modeled, at a high level, the revenue requirement in each year through 2050[56] based on the following assumptions:[57]

- Gas demand declines consistent with PG&E's expected forecast using the E3 Medium-High Electrification Scenario
- Expenditures have a natural growth rate of 3% but decline over time consistent with the decline in gas demand
- Retirements occur consistent with both historical levels of retirements and the decline in gas demand

In order to demonstrate the impact of declining demand, we have calculated the revenue requirement per customer. If we assume the number of customers decline in proportion to the decline in demand of approximately 69% over this period, the resultant revenue requirement per customer would be as follows:

---

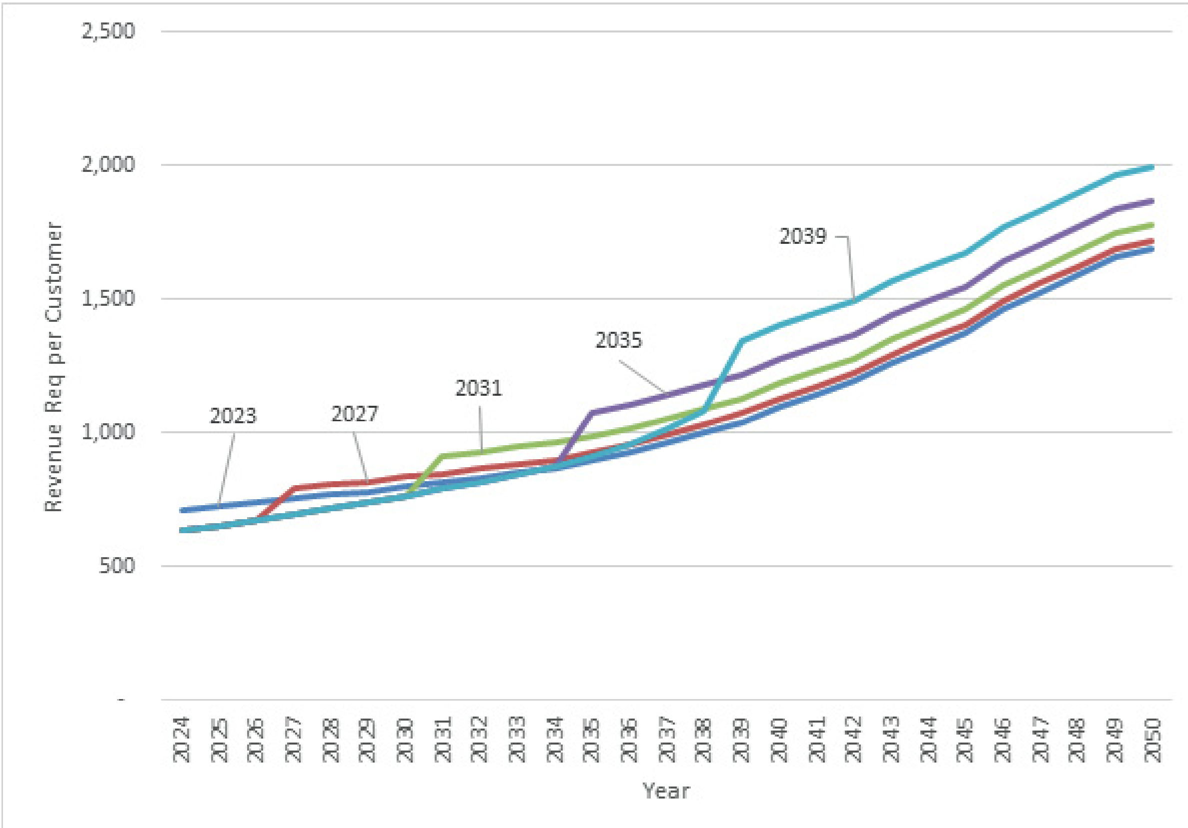
54 Allis, et al, 3 Scenarios Examine the Future of the Natural Gas Industry in the Context of Decarbonization Policies (June 24, 2021), <https://www.gannettfleming.com/blog/3-scenarios-examine-the-future-of-the-natural-gas-industry-in-the-context-of-decarbonization-policies/> (as of July 3, 2022).

55 As I have discussed, this is the electrification scenario which PG&E believes to be the most likely, although PG&E's depreciation proposal is based on the Medium forecast for reasons discussed earlier in my testimony.

56 2050 is the last year of the E3 forecast.

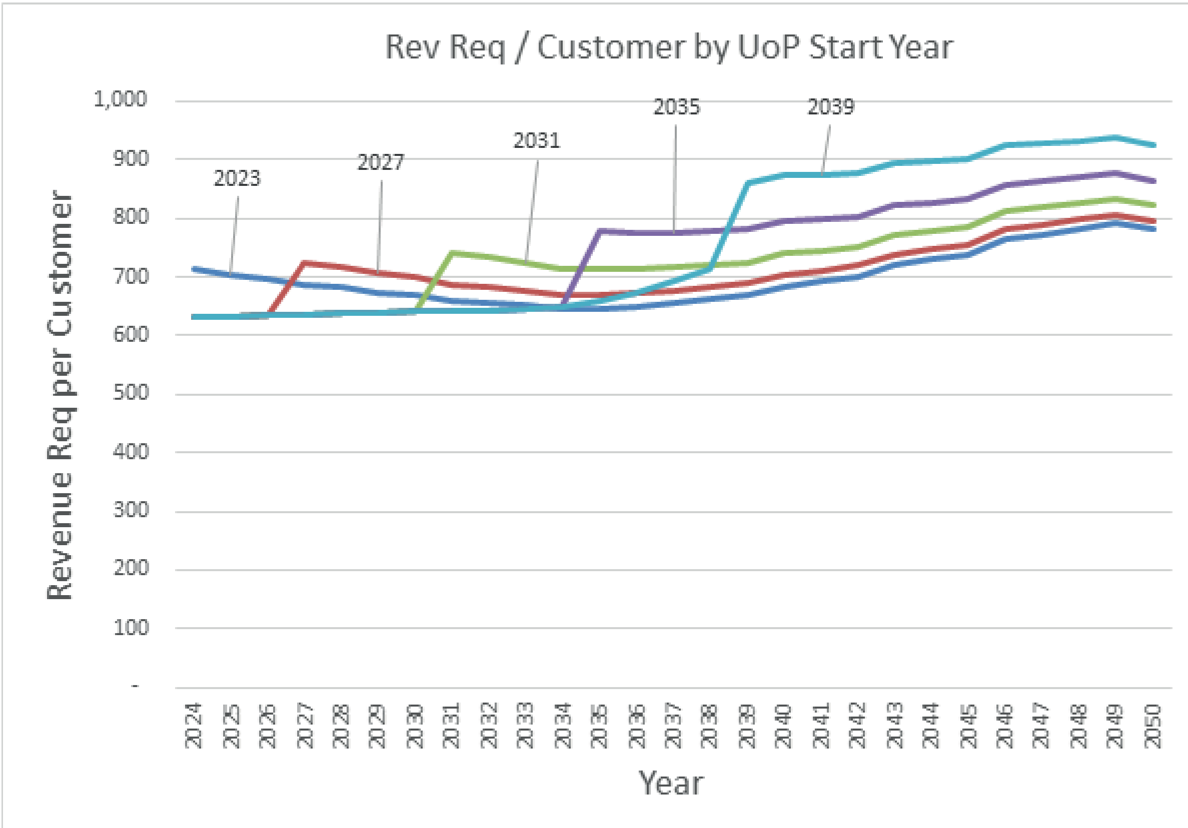
57 I note here that the overall results may vary with different assumptions but the overall concept remains. For example, either a higher electrification scenario or higher rate of expenditure growth would increase the impact on future customers.

FIGURE 12-7
REVENUE REQUIREMENT PER CUSTOMER BASED ON DATE OF IMPLEMENTATION OF UOP METHOD, 2023-2045



As the chart shows, the necessary increases to the revenue requirement and bill impacts are larger the later the UoP Method is adopted. For example, the increase if the UoP Method is implemented in 2027 or 2031 is greater than if implemented in 2023. The impact can also be seen more clearly if we show the results in inflation-adjusted terms, which is provided in Figure 12-8 below.

FIGURE 12-8
INFLATION-ADJUSTED REVENUE REQUIREMENT PER CUSTOMER BASED ON DATE OF IMPLEMENTATION OF UOP METHOD, 2023-2045



This analysis shows the harm in waiting to recognize needed increases in depreciation and demonstrates that the longer the Commission waits the higher the cost. Not only will depreciation need to increase more but rate base will also be higher if we delay increasing depreciation. Since the increase in 2027 is greater than 2023, and the increase in 2031 is larger than the increase in 2027, the later the UoP Method is implemented the greater the impact on customers. Further, rates remain higher if the UoP Method is implemented later.

The analysis also shows that waiting only four years to the next GRC has a large impact. The depreciation increase per customer (and associated increase in revenue requirement) would be almost 20% more in 2027 than the increase in 2023 (and rates would remain higher thereafter).

d. Gas Planning OIR

Q 50 When you were preparing your depreciation study were you aware of the Gas Planning OIR?

A 50 Yes. The Gas Planning OIR was opened on January 27, 2020. I was engaged for PG&E's depreciation study for the 2023 GRC in the spring of 2020. Over the past two years, PG&E has shared information from the Gas Planning OIR with me and we have discussed how depreciation would be impacted by long-term gas planning and climate goals. IS/NCGC witness Brubaker notes his involvement in that proceeding and I am sure other parties are involved as well. While Mr. Brubaker raises several issues considered in the Gas Planning OIR[58], and while Cal Advocates and TURN prefer waiting for more resolution in that proceeding[59], I think it is unlikely that any of the issues parties raise related to the Gas Planning OIR will result in a lower level of depreciation than PG&E proposes. While I do not disagree that issues such as the obligation to serve are important, I do not see how they would significantly reduce depreciation. PG&E's proposal incorporated both PG&E's and my understanding of the Gas Planning OIR proceeding at the time of PG&E's 2023 GRC filing and any developments since the GRC filing have not materially changed PG&E's recommendation.

Q 51 Cal Advocates, TURN and IS/NCGC each argue that the issue of Net Zero by 2045's impact on depreciation is best addressed in the Gas Planning OIR.[60] Do you agree?

A 51 No, at least in the sense that this issue should only be considered and addressed in the Gas Planning OIR. I see no reason why Commission could not address depreciation in both proceedings, as there are advantages and disadvantages to both. While the OIR is a good venue to consider policy aspects of depreciation, my understanding is that full depreciation studies have not been performed for the Gas Planning OIR, nor is the detailed level of testimony and workpapers developed for GRCs included in the Gas Planning OIR. Additionally, I think we can be reasonably certain that no matter the result of the Gas Planning OIR, the Company's undepreciated capital costs for its gas assets (including future

---

58 IS/NCGC-1, pp. 4-9.

59 CA-15, p. 24, line 24 to p. 25, line 9; and, TURN-18, p. 100, line 15 to p. 101, line 4.

60 CA-15, p. 24, line 24 to p. 25, line 9; TURN-18, p. 100, line 15 to p. 101, line 4; and, IS/NCGC-1, pp. 4-9.

decommissioning of gas assets) will need to be recovered faster than in the past.[61]

Further, the Gas Planning OIR does not make depreciation considerations in GRCs irrelevant. The Commission can address depreciation in both the GRC and in the OIR (and the decisions may very well be made at similar times). Given that this GRC establishes a four-year rate plan and given that the longer the Commission waits the more expensive it will be to customers, there is no reason not to incorporate as significant an increase in depreciation as reasonable while still balancing the interests of current and future customers.

Q 52 As discussed above, Cal Advocates, TURN and IS all argue that we should not increase depreciation until there is more information from the Gas OIR. Do you agree?

A 52 No. There is sufficient information and analyses on the impacts to PG&E's gas system to begin to address this issue now. As I have demonstrated, it is important to start sooner rather than later.

e. Response to Cal Advocates' Arguments

Q 53 What arguments does Cal Advocates make against the UoP Method?

A 53 Cal Advocates argues that 1) the phase-in of the UoP Method "masks" its impact; 2) the issue should instead be addressed in the Gas Planning OIR and it is premature to address in PG&E's 2023 GRC; and 3) PG&E has "not always demonstrated a reliable forecast of gas plant utilization,"[62] using the example of the decision to continue to operate the Los Medanos storage facility.

Q 54 Does Cal Advocates offer any technical arguments that the UoP Method would be inappropriate when demand declines significantly or any substantive reasons to doubt the E3 forecast used for the UoP calculations?

---

61 I also think this is true whether through depreciation or some other regulatory mechanism. A different mechanism will still need to recover the same costs, only potentially over a different pool of ratepayers and a different period of time. Either way, customers should pay their fair share of depreciation today, when there are millions of gas customers, as otherwise some future set of ratepayers will bear a disproportionate share of the costs of PG&E's gas distribution system.

62 See, CA-15, p. 24, line 25 to p. 26, line 4.

A 54 No. Cal Advocates' arguments are instead primarily that we should defer any consideration of the impact of Net Zero by 2045 to a later date.[63] Cal Advocates has not contemplated the impacts of Net Zero by 2045 nor has Cal Advocates even attempted to do so.[64] Indeed, as discussed previously, Cal Advocates actually proposes to *decrease* depreciation for gas distribution assets. Their proposal is, therefore, to effectively ignore the issue in this GRC.

Q 55 Please address Cal Advocates' arguments.

A 55 I have previously explained in Section C.2.c that it will be harmful to customers to wait to recognize the impacts of decarbonization on gas depreciation, as it will only result in greater depreciation increases and a higher rate base in future GRCs. Regarding the implication that the phase-in masks the impact of the PG&E's proposal, I disagree. For example, my testimony in Chapter 12 of Exhibit (PG&E-10) shows the full impact of the UoP Method. It also compares PG&E's proposal (once fully phased-in) to other scenarios and demonstrates that there are several future scenarios in which even higher depreciation will be appropriate.[65] As I have explained, PG&E's proposal is relatively moderate and the phase-in of the proposal is an effort to mitigate bill impacts by more gradually moving to the appropriate higher levels of depreciation.

Finally, with regard to criticisms of PG&E's forecast, I first note that Cal Advocates does not raise any specific issues with the long-term gas forecasts produced by E3 or the scenario used by PG&E. Instead, Cal Advocates appears to imply that, because the Company's plans for the Los Medanos storage facility have evolved, a long-term forecast of gas demand on PG&E's system cannot be relied upon.[66] However, not only are plans for a storage field and gas demand forecasts different concepts, but we can be quite certain that PG&E's forecast is more likely to be accurate than the forecast inherent to Cal Advocates' proposal – which, by virtue of ignoring

---

63 CA-15, p. 24, line 17, to p. 26, line 4.

64 See Cal Advocates' response to PG&E's Data Request PGE_CalAdvocates005-Q01, dated 6/27/22 in Appendix A, at the end of this exhibit.

65 See Exhibit (PG&E-10) (Feb. 28, 2022), p. 12-36, Table 12-7.

66 CA-15, p. 25, line 25 to p. 26, line 4.

the impact of decarbonization, is effectively that there will be no impact on gas demand resulting from achieving net zero carbon emissions by 2045.

Q 56 Cal Advocates also argues that the proposal to use UoP depreciation should "require a showing" by PG&E that addresses measures taken to "reduce and/or control the rate of investment" in the gas system and "steps being taken to manage, control and reduce its O&M and A&G costs."[67] Please address this argument.

A 56 Cal Advocates' argument seems to imply that there is a direct link between depreciation expense, which is the recovery of past investments over the remaining time these assets will provide service, and ongoing investment in the gas system as well as current O&M and A&G costs. However, while similar factors may impact these different aspects of the costs to operate a gas system, there is no direct link between these costs and the timing of their recognition from an accounting standpoint.

Q 57 Please explain.

A 57 Depreciation is, by definition, related to the recovery of historical costs over their expected service lives in a systematic and rational manner. This necessarily is reflective of operations over a long period of time (*i.e.*, from the installation of assets through the end of their service lives). Ongoing capital, O&M and A&G are related to current system needs, including safety and reliability, and are based on the current costs to do the needed work (and, therefore, are affected by factors such as inflation). While I would expect that, over time capital spending and other costs will adjust to the needs of the system (meaning, for example, that if the system becomes smaller over time there would likely be reductions to such costs, at least on an inflation-adjusted basis), this will be a function of the needs of the system rather than the level of depreciation expense. As a result, the timing of increases in depreciation and reductions to other costs will not be aligned.

f. Response to TURN's Arguments

Q 58 What arguments does TURN make against the UoP Method?

---

67 CA-15, p. 25, lines 17-20.

A 58 TURN makes several arguments against using the UoP Method.[68] Notably, none are conceptual arguments that the UoP Method would be inequitable when demand declines significantly. Instead, TURN's arguments are 1) consideration of the UoP Method should be deferred to the Gas Planning OIR; 2) the UoP Method does not represent "a balanced approach to addressing the stranded cost risk, which is a risk faced by both PG&E's shareholders and its future customers;" and 3) PG&E's timing is poor because of the overall rate increase in this case.[69] TURN also provides citations to a recent case in California, a case in Massachusetts and the NARUC's *Public Utility Depreciation Practices.*[70]

Q 59 Please address TURN's first argument, that the Commission should defer consideration of the UoP Method to the Gas Planning OIR.

A 59 TURN specifically argues that "the steps to mitigate the potential for stranded costs due to movement toward the state's electrification goals should be considered as part of the overall plan and strategy for meeting those goals. The obvious forum for a review of those issues is R.20-01-007 [the Gas Planning OIR]…"[71] I have in large part already addressed this argument. There is little doubt that decarbonization will have a significant impact on the gas industry and the longer we wait to address the impact on cost recovery the more expensive it will be for customers. Delaying only increases the inequity of any method to address cost recovery, increases risk for both customers and shareholders, and will send improper price signals to the market.

Q 60 Does any of TURN's discussion support PG&E's proposal instead of TURN's proposal?

A 60 Yes. TURN notes that the Gas Planning OIR's scope includes determining:

> the regulatory solutions and planning strategy that the Commission should implement to ensure that, as the demand for natural gas

---

[68] TURN-18, Appendix D.

[69] See TURN-18, pp. 100-102.

[70] TURN-18, p. 99, line 3 to p. 100, line 14.

[71] See TURN-18, pp. 100-102.

declines, gas utilities maintain safe and reliable gas systems at just and reasonable rates, and with minimal or no stranded costs.[72]

First, I note that this passage appears to indicate that the Commission expects a decline in demand for natural gas. In order to be equitable, depreciation should incorporate the impacts of declining demand and, as I have demonstrated in Chapter 12 of Exhibit (PG&E-10), the most equitable way to recover costs with declining demand is the UoP Method. The Commission's statement also indicates that the Commission intends to minimize stranded costs. PG&E's proposal is consistent with this objective. TURN's proposal directly contradicts this goal. Not only does TURN fail to incorporate any impacts of decarbonization on depreciation for gas distribution plant but TURN actually proposes to *decrease* depreciation for gas distribution assets. [73] This is despite that TURN believes service lives for gas mains and services will be shorter than in the past due to Net Zero by 2045.[74] TURN's proposal is not designed in any way to mitigate stranded costs, and, if anything it is designed (whether intentionally or not) to *increase* stranded costs.

Q 61 Please address TURN's second argument, that the Company's proposal does not represent a balanced approach to the risk of stranded costs. [75]

A 61 I have also discussed this previously, but should again point out that it is TURN's proposal that does not represent a balanced approach. As discussed above, the Commission expects gas demand to decline. Balancing the risk of stranded cost means aligning depreciation with this expectation. TURN's proposal to lower depreciation is, in contrast, inconsistent with balancing the interests of current and future ratepayers.

TURN's analysis also appears to be based on the premise that any increase in depreciation necessarily results in current customers bearing an undue share of risk when compared to future customers and shareholders. This is a false premise. Risk is shared when depreciation is established

---

72 *Gas Planning OIR*, R.20-01-007, (Jan. 16, 2020), p. 14.

73 See Table 12-1 earlier in this testimony.

74 See TURN's responses to PG&E Data Requests PGE_TURN006-Q07, dated 6/27/22; and PGE_TURN006-Q08, dated 6/27/22 in Appendix A, at the end of this exhibit.

75 TURN-18, p. 101, lines 5-18.

based on realistic expectations of the future. It is not shared if, for example, depreciation is set at artificially low levels – this favors current customers at the expense of future customers and shareholders and does not balance risk. PG&E's proposal is, in my judgment, based on a realistic expectation of the future and, therefore, balances the risks for future customers, shareholders and current customers as well as can be done based on information available today. TURN's proposal, which, again, is to reduce depreciation for gas distribution assets despite believing that gas service lives will be shorter in the future, is not a balanced approach because depreciation for current customers would be established at a level that any reasonable person would recognize is too low.

Q 62 Please address TURN's third argument, that PG&E's proposal has poor timing.[76]

A 62 First, I do not believe this is a reasonable argument against necessary increases in depreciation expense. Given the long-term impacts of Net Zero by 2045 and the cost impacts this will have, the timing may not be any better in future GRCs, particularly because delaying increases in depreciation will only increase the eventually cost impact. While I recognize the argument for the consideration of rate impacts on depreciation, the fact of the matter is that, as discussed in Section C.1.d, depreciation rates have been held lower – typically to address gradualism or affordability concerns – in each GRC for at least the last decade. Thus, TURN's argument regarding poor timing does not consider that (1) depreciation rates have been held lower than recommended in previous GRCs and (2) delaying necessary increases in depreciation will only further increase future costs, causing a greater burden for future customers.

Q 63 TURN provides a quote from NARUC regarding the UoP Method. Please address this quote.

A 63 TURN quotes the following from NARUC on pages 99 to 100 of Exhibit TURN-18:

> The unit of production method is valid if the primary cause of depreciation is wear and tear. If, as is generally true today, most plant also depreciates because of changes in the art or technology, changes

76 TURN-18, p. 102, lines 1-10.

> in public requirements, obsolescence and other external forces, the unit of production method loses validity.

Other than to note that PG&E did not include this quote in direct testimony, TURN does not provide additional commentary.[77] However, based on a more thorough reading of the discussion in NARUC, the quote cited by TURN does not actually provide any reason why UoP should not be used for gas distribution in the context of declining demand. First, I note that TURN has not included the full paragraph cited by Mr. Finkelstein. The first sentence of this paragraph reads as follows:

> During periods of low, production, such as a business recession, or when demand for services is declining, the unit of production method tends to find more favor, because it may moderate heavy fixed charges to conform to services rendered and revenues received.[78]

In context, the paragraph TURN cites is related to a discussion of considerations in assessing whether the straight-line method or UoP method is more appropriate. I agree that, under normal operating conditions, the various forces of retirement combine with large groups of property (such as gas mains) and, forces other than just wear and tear impact service lives, straight-line depreciation based on service life estimates that consider all of these factors is typically most appropriate. However, this does not mean that UoP is only appropriate when wear and tear is the primary cause of retirement. Indeed, as evidence that this passage is not intended to be universal for all circumstances, UoP has been used for decades for gas production facilities for which the primary cause of retirement is not wear and tear.

However, the circumstances for PG&E's gas distribution system are quite different from normal operating conditions. If gas demand declines significantly, as Commission has indicated it believes it will, then obsolescence will become a more dominant cause of retirement and the utilization of gas distribution assets will be more of a function of future gas demand than of historical causes of retirement. Indeed, NARUC's discussion observes the following when assessing the UoP method:

---

77 TURN-18, p. 99, line 21 to p. 100, line 2.

78 NARUC, *Public Utility Depreciation Practices* (1996), p. 53.

> The crucial tests are whether total service can be more accurately forecast in production units or in years of life span and whether consumption is entirely unrelated to age or is reasonably related to age.[79]

Based on expectations for declining gas demand, in my judgment total service can be more accurately determined based on forecasts of future gas throughput than using traditional methods for estimating service lives and the straight-line method. Further, achieving net zero carbon emissions by 2045 will largely minimize the relationship of consumption to age – consumption is expected to decrease and will likely do so for areas of the service territory that have newer assets and those that have older assets.

I again emphasize that the circumstances for the gas industry in California are unique and unprecedented. In 1996, when *Public Utility Depreciation Practices* was published, NARUC would not have been able to envision that large portions of gas distribution systems would face obsolescence and significantly declining demand. The importance of NARUC's discussion is that UoP is recognized by NARUC as an appropriate method that can be used in the appropriate circumstances. Authoritative texts like NARUC discuss many methods of depreciation because there may be circumstances that arise in which a lesser used but still valid method may be most appropriate. Based on my work considering the impacts of GHG emissions on depreciation, in my judgment the UoP Method is more appropriate and equitable than the straight-line method when gas demand will decline significantly.

Q 64 On page 99 of Exhibit TURN-18, TURN also quotes from a decision from a September 30, 2021 in case in Massachusetts. Please address TURN's discussion of this case.

A 64 I first note that TURN's characterization of the proposal in that proceeding (and in general with cases in New York and Massachusetts) is incorrect. The cited case was for Boston Gas Company (a National Grid subsidiary). Boston Gas Company did not propose accelerated depreciation as TURN

---

79 NARUC, *Public Utility Depreciation Practices* (1996), p. 52.

implies.[80] It also did not propose the UoP Method, although that method was discussed and presented in testimony in the case. Instead, Boston Gas Company's proposal was to shorten service lives for several accounts by 10 years (which was phased in over the rate years in that case). It was also, to my knowledge, one of the first cases in which a utility proposed changes to depreciation due to decarbonization goals. There have been several analyses and developments since Boston Gas Company's filing and the Massachusetts Department of Public Utilities (DPU) order that have further affirmed the need to increase depreciation, one of which includes analysis of the UoP Method in the Massachusetts DPU's gas planning proceeding.[81] In other words, the DPU's decision to defer recognizing the impacts of depreciation does not eliminate the need to have higher depreciation – nor does it change that higher depreciation will be needed sooner rather than later.

Indeed, one of the criticisms raised in the Boston Gas Company case (and which has also been raised in cases in New York), was that a proposal to decrease lives by five or ten years was not tied to planning scenarios or forecasts. PG&E's proposal does not have this issue as its proposal using UoP Method is based on a specific gas demand forecast.

While I believe the Massachusetts DPU's decision was unfortunate for Boston Gas Company customers, the DPU does have an ongoing gas planning proceeding in which the UoP Method is being considered. Because the Massachusetts DPU has deferred addressing depreciation to this planning proceeding, I would expect that in that proceeding the DPU will either conclude that UoP is most equitable or develop a different ratemaking mechanism that similarly balances the interests of current and future customers.

---

80 See TURN-18, p. 99, lines 3-19, and TURN's response to PG&E Data Request PGE_TURN006-Q17, dated 6/27/22 in Appendix A, at the end of this exhibit.

81 See, for example, the presentations of the Local Distribution Companies and Scott Madden from the April 15, 2022 technical session in Mass. DPU 20-80.

Q 65 TURN also cites to a recent case for PacifiCorp, in which TURN claims the Commission "addressed a similar circumstances."[82] How do you respond to this discussion?

A 65 First, I disagree that the circumstances are similar. PacifiCorp operates in six state jurisdictions and owns several coal-fired generation facilities across the western United States. PacifiCorp's jurisdictions disagree on the outlook for coal-fired generation (with, e.g., Utah expecting longer life spans than Oregon), which creates uncertainty about the future lives of these facilities. The Commission's decision in the PacifiCorp case appears to be influenced, at least in part, by this dynamic and the resultant implication that PacifiCorp does not have specific plans to retire certain coal-fired facilities.[83] Additionally, as I have discussed, the intergenerational equity concerns are considerably more pronounced for PG&E's gas system due to the potential for a decline in consumption, customers or both than for PacifiCorp's electric system.

One other item is of note. In the order cited by TURN, the Commission recognizes that higher depreciation now "can mitigate later increases in ratepayer rates due to early retirement of coal plants in the future and avoid the potential that ratepayers pay costs of early retirement and costs of replacement power at the same time."[84] The same is certainly true for PG&E's gas assets, except with the additional circumstance that gas demand is likely to decline and the myriad challenges this will produce.

Given these considerations, the facts presented in the PacifiCorp decision are distinct from the circumstances here regarding PG&E's gas distribution assets. PG&E's depreciation proposal is consistent with expectations of long-term gas demand and is most reasonable based on the information available today.

g. Response to IS/NCGC's Arguments

Q 66 What arguments does IS make regarding the UoP Method?

---

[82] TURN-18, p. 100, lines 7-8.

[83] D.20-02-025, pp. 25-27.

[84] D.20-02-025 (A.18-04-002, PacifiCorp GRC, Test Year 2019), p. 28.

A 66 IS witness Brubaker also makes several arguments against the UoP Method. Some are the same as addressed previously, including deferring any recognition of climate policies on depreciation to the Gas Planning OIR.[85] Mr. Brubaker also criticizes the Company's gas forecast and argues that the Company has not taken into consideration alternative fuels like renewable natural gas (RNG) and hydrogen.[86] He also argues that the UoP Method is not appropriate for gas distribution assets.[87]

I will not repeat my response to arguments already addressed, such as why it is important to begin to recognize the impacts on depreciation today rather than wait for a ruling in the Gas Planning OIR, and PG&E witness David Sawaya also addresses IS/NCGC's criticisms of PG&E's gas throughput forecast.[88] In general, PG&E's forecasts and proposals are consistent with my experience, and I note that Mr. Brubaker does not offer any alternative or specific reasons to doubt the specific E3 forecast used for PG&E's proposal. Further, while he discusses alternative uses for PG&E's system, such as RNG,[89] I think it is unlikely that PG&E's current gas demand could be entirely replaced by RNG. In other words, even with these alternatives it is likely that demand will decline and the UoP Method will be most appropriate.

Q 67 Please address Mr. Brubaker's argument that the UoP Method is not appropriate for gas distribution assets.[90]

A 67 There are two aspects to his argument. The first is that there is not a precedent for using the UoP for gas distribution assets. I have addressed this previously, but this is to be expected – the situation facing PG&E's gas system is unprecedented. We should not expect a precedent of using the UoP Method for gas distribution assets because until very recently there was not a need for this method for gas distribution assets.

---

85 IS/NCGC-1, p. 9, lines 11-15.

86 IS/NCGC-1, pp. 4-7 and pp. 9-10.

87 IS/NCGC-1, pp. 10-12.

88 Exhibit (PG&E-23), Ch. 12A.

89 IS/NCGC-1, pp. 9-10.

90 IS/NCGC-1, pp. 10-12.

Mr. Brubaker also attempts to contrast the forces of depreciation acting on gas gathering systems, for which he acknowledges the UoP Method has been used, and gas distribution systems. He argues that because the considerations in these FERC cases were at least in part "based on depletion of the natural gas resource which would render the gathering system assets obsolete" and that once the natural resources were depleted, the gathering systems "no longer would be of value because there would be nothing to transport." He concludes that the differences between gathering systems and distributions systems "couldn't be more pronounced."[91]

Mr. Brubaker's argument fails to recognize that, in the context of significant declines in gas demand due to climate policies, the forces impacting depreciation for gas distribution assets will be similar to those he describes for gas gathering assets. The physical characteristics of each system are not the most relevant consideration when determining the appropriate depreciation method in these circumstances. Instead, it is other forces of retirement and depreciation that should be considered. For a gas gathering system, Mr. Brubaker is correct that the exhaustion of supply renders the physical assets obsolete. UoP is appropriate in such situations. However, he does not acknowledge that a significant decline in gas demand will similarly render gas distribution assets -- such as services, meters and even mains – obsolete in a similar way. In other words, just as with gathering systems, obsolescence and declines in utilization for PG&E's gas distribution system will have a more pronounced impact than physical characteristics and, just as UoP can be appropriate for gas gathering systems, the same is true for gas distribution systems that face the specific circumstances of PG&E's system.

Q 68 IS/NCGC also references a comment by PG&E in the Long-Term Planning OIR that "decommissioning most of the natural gas system will require somewhere between 50 to 100 years to complete."[92] Please address this comment.

---

91 IS/NCGC-1, p. 11, lines 15-16.

92 IS/NCGC-1, p. 5, lines 12-15.

A 68 PG&E's expectation of the time it would take to fully decommission most of its gas system is distinct from the recovery of costs using the UoP Method. The UoP Method is designed to align cost recovery with throughput. Throughput can decline without decommissioning most of PG&E's system if, for example, per-customer demand increases. Further, the forecast for PG&E's proposal still incorporates an expectation that there will be gas demand in thirty years, even if at a lower level. As a result, PG&E's proposal does not incorporate an expectation that most of its gas system will be decommissioned over the next three decades.

3. Service Lives

a. General

Q 69 Does Cal Advocates generally concur with your service life and curve recommendations?

A 69 Yes. I have made service life (ASL and survivor curve) recommendations for nearly 110 accounts. Cal Advocates only proposes an adjustment to the service life estimate for one electric account, Account 364, Poles, Towers and Fixtures, and two gas accounts, Account 376, Mains and Account 380, Services.[93]

Q 70 What does TURN propose?

A 70 TURN proposes longer service lives for 11 electric accounts, 6 gas accounts, and 1 common plant account.[94]

Q 71 Please summarize the service life estimates of each party.

A 71 For the accounts at issue in this case, Table 12-2 below provides a comparison of the service life estimates authorized in both the 2017 and

93 CA-15, p. 11-16.

94 TURN-18, p. 8, Table 3.

2020 GRCs[95] with the proposals of each party.[96] I note that this section will address each of the accounts below except for the intangible software accounts. Those accounts will be addressed in Section C.5.

[95] See, A.15-09-001, Joint Motion for Adoption of Settlement Agreement (Aug. 3, 2016), Appendix C, Settlement Agreement (as ratified by D.17-05-013), for the parameters authorized in the 2017 GRC. See, A.18-12-009, Joint Motion for Approval of Settlement Agreement, Attachment A, (Jan. 14, 2020), as ratified by D.20-12-005, for the parameters authorized in the 2020 GRC. Additionally, see, D.19-09-025, Exh. JS-03 for the authorized service lives from the 2019 Gas Transmission and Storage case and D.16-06-056, Exh. Joint-1 for the authorized service lives from the 2016 Gas Transmission and Storage case.

[96] The first number listed in the table is the ASL and the second is the Iowa curve type. Thus, for example, a 44-R2 survivor curve has a 44-year ASL and an R2 survivor curve type.

TABLE 12-2
COMPARISON OF PG&E, CAL ADVOCATES AND TURN SERVICE LIFE ESTIMATES

Line No.	FERC Account	2017 GRC / 2016 GT&S Authorized Estimate	2020 GRC / 2019 GT&S Authorized Estimate	PG&E Estimate	Cal Advocates Estimate	TURN Estimate
1	Electric Intangible					
2	303.03, Computer Software	5-SQ	5-SQ	5-SQ	5-SQ	10-SQ
3	Electric Transmission					
4	353.02, Step Up Trans.	55-R1.5	55-R1.5	55-R2	55-R2	63-R1.5
5	353.03, Step Up Trans. – CC	55-R1.5	55-R1.5	55-R2	55-R2	63-R1.5
7	Electric Distribution					
8	362, Station Eq.	46-R1.5	46-R1.5	50-R1	50-R1	53-R1
9	364, Poles, Towers & Fixt.	44-R1.5	44-R2	44-R2	47-R1.5	52-R2
10	365, OH Conductors and Dev.	46-R2	46-R2	44-R1.5	44-R1.5	48-R1.5
12	367, UG Conductors and Dev.	47-R3	50-R3	52-R3	52-R3	55-R3
13	368.01, Line Trans. – OH	32-R2.5	32-R2.5	32-R2.5	32-R2.5	35-R2.5
14	368.02, Line Trans. - UG	31-R3	33-R2.5	34-R2.5	34-R2.5	37-R2.5
15	369.01, Services – OH	52-R2.5	55-R2.5	55-R2.5	55-R2.5	64-R2
16	369.02, Services – UG	45-R4	50-R4	50-R4	50-R4	58-R3
	Gas Intangible					
17	303.02, Computer Software	5-SQ	5-SQ	5-SQ	5-SQ	10-SQ
	Gas Transmission					
18	367, Mains	62-R2	66-R2	65-R2	65-R2	68-R2
19	367, Mains - Stanpac	62-R2	66-R2	65-R2	65-R2	68-R2
	Gas Distribution					
20	376 Mains	57-R3	57-R3	57-R3	60-R3	57-R3
21	378, M&R Station Equipment	55-R2	55-R2	55-R2	55-R2	59-R2
22	380, Services	57-R3	57-R3	55-R3	59-R3	60-R3
23	381, Meters	28-S1	28-S1	28-S1	28-S1	31-S1
24	383, House Regulators	28-R2	28-R2	28-R2	28-R2	32-R2
	Common					
25	303.02, Computer Software	5-SQ	5-SQ	5-SQ	5-SQ	10-SQ

As can be seen in the table, with the exception of one electric account and two gas accounts, PG&E's proposal is either to increase the ASL or to continue to use the currently authorized estimate. PG&E has proposed service life estimates in a manner consistent with the concept of gradualism set forth in the Commission's Decision in the 2014 GRC.[97]

In contrast, some of TURN's proposals represent fairly significant increases in ASL that are not consistent with the concept of gradualism. As

[97] This concept is discussed in more detail in Section C.1.e.

can be seen in Table 12-2, for five of the accounts, TURN witness Garrett proposes a service life that is eight or more years longer than what was authorized in the 2020 GRC. As discussed previously, TURN also proposes to increase the lives of gas mains and services despite believing that these assets will have shorter lives in the future.[98]

Q 72 Does PG&E agree with Cal Advocates' proposal?

A 72 No. Cal Advocates proposes a change in service life to three accounts -- one electric account and two gas accounts.[99] PG&E's estimates for these accounts are superior for at least two primary reasons: (1) PG&E's estimates incorporate important factors that should be expected to influence the lives of PG&E's assets; and (2) PG&E's estimates are more consistent with the impact of Net Zero by 2045. Cal Advocates even proposes to increase the lives of gas distribution mains and gas distribution services – the two largest gas distribution accounts.[100] Increasing service lives in the midst of an uncertain time in which significant portions of the gas system could be obsolete is not appropriate. As both of these factors also apply to my response to TURN's proposals, I will address these concepts in more detail in the next three sections of my rebuttal testimony.

Q 73 Does PG&E agree with TURN's proposals?

A 73 No. The same considerations discussed above for Cal Advocates' proposal also apply to TURN's proposal. There are also additional differences between TURN's approach and PG&E's (and Cal Advocates') approach. Mr. Garrett's analysis is only based on 22 years of the Company's experience. While a longer period of data was available, Mr. Garrett did not use the longer history because the vintage years of PG&E's recorded retirements were statistically aged[101] (as I will discuss in more detail in Section C.3.d, Mr. Garrett incorrectly refers to this as "manufactured" data). Additionally, Mr. Garrett has incorporated limited information external to

---

98 See TURN's response to PG&E Data Request PGE_TURN006-Q17, dated 6/27/22 in Appendix A, at the end of this exhibit.

99 CA-15, pp. 11-16.

100 See, Table 12-2 (above), and Exhibit (PG&E-10) (Feb. 28, 2022), p. 12-6 to p. 12-8, Table 12-2.

101 TURN-18, p. 13, lines 10-11 and p. 16, lines 1-14.

the statistical analysis into his estimates. Indeed, he even appears to disparage the widely-accepted concept of incorporating information provided by Company Subject Matter Experts (SMEs).[102] Each of the issues affecting the proposals of both Cal Advocates and TURN will be discussed in the following sections.

b. The Estimation of Service Lives Is Not a Purely Mathematical Exercise and Must Incorporate Informed Judgment

Q 74 Based on your review of their testimony, have Cal Advocates and TURN used the same approach for estimating ASLs and survivor curves as used in PG&E's depreciation study?

A 74 No. Both Cal Advocates and TURN have failed to incorporate information other than the results of statistical analyses. While, as I discuss, it is always important to incorporate information external to the statistical analysis when making service life estimates, it is particularly important when we know that the future will be different from the past. While Cal Advocates has only recommended a different service life estimate from PG&E for three accounts, each of these accounts is either a gas distribution account or overhead electric distribution account. We know that assets in these accounts will be retired or replaced more quickly than in the past and, therefore, it is unreasonable for Cal Advocates to increase the service lives for these accounts.

TURN has proposed adjustments to several more accounts. TURN's approach also differs from PG&E's in that TURN's proposals are primarily, if not entirely, based on mathematical results. [103] Similar to Cal Advocates, these include accounts where we can be reasonably certain that lives in the future will be shorter than those than in the past, such as for gas distribution and electric overhead distribution accounts. TURN has also only relied on 22 years of data, as opposed to the much longer historical period available, which further influences Mr. Garrett's results. The use of a shorter period of data should provide reason for Mr. Garrett to incorporate more judgment and rely more on gradualism, because there is less certainty when a

---

[102] TURN-18, pp. 19-20.

[103] TURN-18, p 14, line 20 to p. 15, line 2.

relatively short period of data is used.[104] However, he has done the opposite.

Both parties' approaches also differ from the correct and proper approach to estimating service lives supported by SP U-4 and authoritative depreciation textbooks such as the NARUC's publication *Public Utility Depreciation Practices*. The discussions in both Cal Advocates' and TURN's testimonies focus almost entirely on statistical analyses and, combined with their proposals to move lives for accounts in the opposite direction one would reasonably expect, indicate that they believe estimating service lives is primarily a mathematical exercise in which little more than mathematical computations of historical accounting data will result in reasonable estimates of future service lives. This is incorrect. Depreciation, and particularly the estimation of service lives, is a forecast of the future rather than a calculation of what has happened in the past.

Q 75 Please explain in more detail how Cal Advocates and TURN's approaches do not align with the proper manner in which service life estimates should be determined.

A 75 Consider, as an example, the following statement from Mr. Garrett's testimony in which he describes his approach. He is asked if he always selects the "mathematically best-fitting curve." While Mr. Garrett claims that he does not always do so, he states the following:

> Mathematical fitting is an important part of the curve-fitting process because it promotes objective, unbiased results. However, while mathematical curve fitting is important, it may not always yield the optimum result. For example, if there is insufficient historical data in a particular account and the OLT curve derived from that data is relatively short and flat, the mathematically "best" curve may be one with a very long average life. However, when there are sufficient data available, mathematical curve fitting can be used as part of an objective service life analysis.[105]

---

104 As an example, when discussing the selection of bands, NARUC explains the value of a longer period of history due to an increased sample size:

> [I]n statistical analysis, the larger sample size in relation to the universe (the body of all data), the greater the reliability of the result (i.e., the greater the probability that the results will be applicable to the universe as a whole).

See NARUC, *Public Utility Depreciation Practices*, 1996, p. 113.

105 TURN-18, p. 14, lines 11-17.

Mr. Garrett's testimony gives the impression that mathematical results should generally be accepted and instances in which the proper service life estimate is not a best "mathematical fit" would be a relatively unusual exception (such as if there is insufficient data). His reasoning for reliance on mathematical results is that doing so promotes "objectivity." While I recognize the intuitive appeal of objective results, presumably to remove uncertainty and make the job of estimating service lives easier, the objectivity sought by Mr. Garrett is neither realistic nor desirable in the development of a reasonable forecast of the future. It will, and does, produce unrealistic and unreasonable results. Further, authorities on the topic of depreciation, such as SP U-4 and NARUC, are quite clear that estimating service lives must include a subjective component.

Q 76 Does SP U-4 explain the need to use judgment when estimating service lives?

A 76 Yes. Chapter 5, Paragraph 2 of SP U-4 states:

> <u>Determination of the remaining life basically involves the judgment estimate of the engineer as to the future effect of wear and tear, decay, action of the elements, inadequacy, obsolescence, and public requirements</u>. In special cases other factors may be important, such as anticipated changeovers to new or improved major units of plant, and other specific plans of management. To arrive at a satisfactory estimate of future conditions, the past experience generally gives indications which may be used as a major element in the remaining life estimate. <u>The weight to be given past experience depends upon the extent to which conditions affecting service life in the future are expected to be similar to or different from those in the past</u>. However, substantial weight is generally given to results of past experience in the same or comparable properties.[106]

I note here that SP U-4 recognizes that the intent is to determine the "future effect" of these factors – not the past effect. As I have discussed, there are multiple reasons to expect that conditions affecting service lives in the future will be different from those in the past. Thus, even if there are often cases in which it is appropriate to give "substantial weight" to past experience, the instant case is not necessarily one of those situations.

---

106 CPUC, *Determination of Straight-Line Remaining Life Depreciation Accruals* – SP U-4, (Jan. 3, 1961, p. 15.

Q 77 Does NARUC also explain the importance of a subjective component to estimating service lives?

A 77 Yes. NARUC makes explains that there must be a subjective component to estimating service lives. Chapter XIII of Public Utility Depreciation Practices, entitled “Actuarial Life Analysis” discusses and emphasizes the subjective nature of the process of estimating service lives. NARUC starts this chapter by explaining that the analysis of historical data is only one part of the process of estimating service lives:

> Actuarial analysis objectively measures how the company has retired its investment. The analyst must then judge whether this historical view depicts the future life of the property in service. The analyst takes into consideration various factors, such as changes in technology, services provided, or capital budgets.[107]

NARUC also explains that the process of estimating service lives must go beyond any objective measurement of the past. In describing the determination of a survivor curve estimate (referred to as the “projection life” in this passage), NARUC states:

> <u>The projection life is a projection, or forecast, of the future of the property</u>. Historical indications may be useful in estimating a projection life curve. Certainly the observations based on the property’s history are a starting point. Trends in life or retirement dispersion can often be expected to continue. Likewise, unless there is some reason to expect otherwise, stability in life or retirement dispersion can be expected to continue, at least in the near term.
>
> <u>Depreciation analysts should avoid becoming ensnared in the mechanics of the historical life study and relying solely on mathematical solutions</u>. The reason for making an historical life analysis is to develop a sufficient understanding of history in order to evaluate whether it is a reasonable predictor of the future. <u>The importance of being aware of circumstances having direct bearing on the reason for making an historical life analysis cannot be understated</u>. <u>These circumstances, when factored into the analysis, determine the application and limitations of an historical life analysis</u>.[108]

---

107 NARUC, *Public Utility Depreciation Practices*, (1996), p. 111.

108 NARUC, *Public Utility Depreciation Practices*, (1996), p. 126. (Emphasis added).

Thus, NARUC strongly advises against the approach used by Cal Advocates and TURN, stating clearly that "relying solely on mathematical solutions" should be avoided. NARUC further elaborates on the need for a subjective component to forecasting service lives:

> A depreciation study is commonly described as having three periods of analysis: the past, present, and future. The past and present can usually be analyzed with great accuracy using many currently available analytical tools. The future still must be predicted and must largely include some subjective analysis. *Informed judgment* is a term used to define the subjective portion of the depreciation study process. It is based on a combination of general experience, knowledge of the properties and a physical inspection, information gathered throughout the industry, and other factors which assist the analyst in making a knowledgeable estimate.
>
> The use of informed judgment can be a major factor in forecasting. A logical process of examining and prioritizing the usefulness of information must be employed, since there are many sources of data that must be considered and weighed by importance. For example, the following forces of retirement need to be considered: Do the past and current service life dispersions represent the future? Will scrap prices rise or fall? What will be the impact of future technological obsolescence? Will the company be in existence in the future? The analyst must rank the factors and decide the relative weight to apply to each. The final estimate might not resemble any one of the specific factors; however, the result would be a decision based upon a combination of the components.[109]

NARUC also explains:

> The use of informed judgment sometimes becomes a point of controversy in the regulatory setting because some of the analyst's opinions cannot be quantified or easily supported. It is sometimes impossible to pinpoint the reasons for making a decision that diverges from a company's historical data or standard reference material. For instance, limited retirement data show that a new transformer design appears to have significantly shorter service life; this would result in a significantly higher depreciation rate. Since this is a new design, there is no field experience to apply to the estimate, other than the scant data. Should the rate be based solely on the data? In the other extreme, should this preliminary data be given little weight and should the rate be based upon other types of transformers as reasonable indicators of the life of this

---

109 NARUC, *Public Utility Depreciation Practices*, (1996), p. 128. (Emphasis added).

> new design? It is the analyst's responsibility to apply any additional known factors that would produce the best estimate of service life. The analyst's judgment, comprised of a combination of experience and knowledge, will determine the most reasonable estimate.

In summary, several factors should be considered in estimating property life. Some of these factors are:

1) Observable trends reflected in historical data;
2) Potential changes in the type of property installed;
3) Changes in the physical environment;
4) Changes in management requirements;
5) Changes in government requirements; and
6) Obsolescence due to the introduction of new technologies.[110]

I note here that, similar to the FERC definition of depreciation and SP U-4, a number of specific factors to consider are enumerated, including changes in the physical environment, changes in government requirements and obsolescence.

As I have discussed, factors that will lead to retirements and replacements of the Company's assets, including the impact of decarbonization on gas assets and wildfire hardening on electric overhead distribution assets, should result in shorter service lives than indicated by the Company's historical data. Cal Advocates' and TURN's failure to incorporate these factors is inconsistent with the guidance of SP U-4 and NARUC.

Q 78 Have you incorporated the various factors discussed by SP U-4 and NARUC into your estimates?

A 78 Yes. For prior depreciation studies, I conducted site visits and had discussions with Company SMEs to familiarize myself with the Company's assets. I also conducted similar discussions for the current study, although site visits were not feasible due to restrictions related to COVID-19. The information I have obtained has been discussed in the workpapers supporting Exhibit (PG&E-10), Chapter 12, and additional factors are

---

[110] NARUC, *Public Utility Depreciation Practices*, (1996), p. 129. (Emphasis added).

discussed in more detail in the next section. In addition, throughout my career, I have participated in over a hundred depreciation studies for numerous utilities. The information obtained from this experience has also been incorporated into my recommendations.

Q 79 Has Cal Advocates incorporated these factors into their recommendations?

A 79 No. Not only does Cal Advocates not discuss these factors in its testimony related to its service life estimates but Cal Advocates' proposals to increase the lives for gas distribution assets and for electric distribution poles makes clear these factors have not been given due consideration.

Q 80 Has TURN witness Garrett incorporated these factors into his recommendations?

A 80 No. First, the fact that TURN has also proposed to increase the lives of gas distribution and electric overhead distribution assets makes clear that Mr. Garrett has not given due consideration to these factors. Mr. Garrett also explicitly stated in the response to discovery:

> Mr. Garrett has not analyzed California's state goals for carbon neutrality or the likely impact on service lives for gas mains.[111]

Given this response, Mr. Garrett's claim in his testimony that he considered all information available to him[112] is inaccurate and misleading.

Further, Mr. Garrett describes his differences from my proposals as follows:

> For most of the accounts in which I propose a longer service life, such proposal is based on the objective approach of choosing an Iowa curve that provides a better mathematical and/or visual fit to the observed historical retirement pattern derived from the Company's plant data.[113]

Again, estimating service lives is not and should not be a purely mathematical exercise and must incorporate some degree of subjectivity. TURN believes the future will be different[114] from the past and this

---

[111] See TURN's response to PG&E Data Request PGE-TURN006_Q09, dated 6/27/22 in Appendix A, at the end of this exhibit.

[112] TURN-18, p. 21, lines 6-7.

[113] TURN-18, p. 14, line 22 to p. 15, line 2.

[114] See TURN's responses to PG&E Data Requests PGE_TURN006-Q07, dated 6/27/22, and PGE_TURN006-Q08, dated 6/27/22 in Appendix A, at the end of this exhibit.

expectation should be incorporated into service life estimates. Mr. Garrett's process for estimating service lives, as described in his testimony, does not follow the proper approach of incorporating informed judgment. It is particularly important for PG&E's current case, due to a number of factors that will influence service lives in the future. These are discussed in more detail in the next section.

Q 81 Mr. Garrett criticizes the use of information obtained from discussions with Company personnel.[115] Please address his comments.

A 81 Mr. Garrett argues that, contrary to the recommendations of NARUC and other authorities, limited consideration should be given to information provided by SMEs and that "service life estimates should be objectively based on unbiased facts—facts that are properly obtained from the utility's (real) historical data."[116] As discussed above, the importance of informed judgment and knowledge of the property studied, which by necessity, must incorporate information obtained from the Company, is emphasized in SP U-4 and NARUC. Thus, Mr. Garrett's opinion is not supported by depreciation authorities.

Further, the arguments made by Mr. Garrett do not stand up to scrutiny and instead represent a lack of understanding of the depreciation study process and the concept of informed judgment. A depreciation study is a forecast of what will occur in the future. In order to forecast the future, it is entirely necessary to seek the input of those most knowledgeable about the Company's assets (i.e., Company SMEs).

Q 82 Please address Mr. Garrett's comments that it does not make sense to "place much reliance on the opinions of the very applicant who hired it."[117]

A 82 The implication in Mr. Garrett's testimony is that PG&E's SMEs would be biased to provide information to support shorter lives or more negative net salvage, thereby increasing depreciation expense. However, Mr. Garrett's comments are based on nothing more than his unsupported opinion, particularly because Mr. Garrett's interactions with any company SME's has

---

115 TURN-18, pp. 19-20.

116 TURN-18, p. 20, line 20 to p. 21, line 2.

117 TURN-18, p. 20, lines 9-10.

been quite limited. In the cases in which Mr. Garrett has been involved in which my firm performed a depreciation study, I do not recall any in which Mr. Garrett conducted meetings with SMEs (or site visits for that matter). To my knowledge he has conducted few, if any, such meetings. His opinions on this information are not based on any of his own actual experience. In contrast, in my experience conducting numerous meetings with SMEs across the country, I have not found it to be the case that SMEs would intentionally be biased towards supporting shorter lives or more negative net salvage. If anything, when I have directly discussed service lives of various assets, I have often found that SMEs intuitively overstate service lives because they typically opine on the physical lives of various assets, whereas other factors, such as relocations and capacity replacements, tend to result in a shorter overall average life in utility operations.

I also should emphasize that the service life and net salvage estimates are based on my professional judgment and not that of PG&E. While discussions with SMEs provides very important information that is incorporated into that judgment, the degree to which that information is considered in my recommendations is a function of my experience and judgment, not any financial metrics of the Company.

Q 83 Please address Mr. Garrett's argument that he has the same information that you used in the study because he requested it in discovery.[118]

A 83 Mr. Garrett implies that because he requested in discovery all of the information I have obtained from site visits and meetings with Company personnel, there is no way that my judgment could be superior to Mr. Garrett's unless information was withheld in discovery. This implication represents a fundamental misunderstanding of the concept of informed judgment. While I have indeed responded to discovery information provided by the Company for the depreciation study, a depreciation expert does not rely only on information obtained from a single study. Rather, I have worked on over a hundred depreciation studies for utilities across the country, including multiple depreciation studies for PG&E. This experience helps to understand, for example, differences between operating an electric or gas

118 TURN-18, pp. 19-20.

system in California compared to other parts of the country. I am active in industry organizations and attend multiple conferences each year in which depreciation or topics related to depreciation are discussed. I have also learned from and have had numerous discussions with colleagues at Gannett Fleming that also have many decades of experience performing hundreds of depreciation studies. While all of this knowledge and experience cannot be written into a response to a discovery question, it provides a critical component of the judgments that go into a depreciation study.

As I will discuss in more detail in the following sections, the various judgments that differ between my estimates and those of Mr. Garrett are based on this experience, knowledge and understanding of PG&E's system. As an example, an understanding of the development of the historical data through multiple studies, as well as events over the previous two decades, support my reasonable conclusion that a longer period of data should be used in the statistical life analysis than the 22 years used by Mr. Garrett. I also understand that the factors influencing asset lives in California are different from many other parts of the country.

There is no evidence that Mr. Garrett has considered these factors in developing his proposals. To the contrary, as I discuss in the following sections, there are numerous reasons to doubt that Mr. Garrett's proposals will result in reasonable forecasts of the future experience of PG&E's assets.

c. Factors Influencing PG&E's Future Service Lives

Q 84 Are there any specific factors that would influence the service lives of PG&E's assets that you would like to address?

A 84 Yes. As discussed previously, SP U-4 and other depreciation authorities recognize the need to incorporate factors such as obsolescence, changes to the natural environment and requirements of public authorities into recommended depreciation parameters and rates. Each of these factors will influence PG&E's assets going forward to a greater degree than has been the case in the past. As a result, TURN's general approach to estimating service lives is fundamentally flawed and results in service lives that overstate realistic expectations for PG&E's assets.

Q 85 Please explain.

A 85 As the Commission is aware, and as I have discussed previously in this testimony and in my direct testimony,[119] there are numerous changes occurring in California that will impact both the electric and gas industries. New technologies are changing the way electricity is generated and delivered. Statewide emissions goals will affect the usage of electric and gas assets. As discussed throughout my testimony, it is likely that California's Net Zero by 2045 goal will result in portions of the natural gas system being retired earlier than previously anticipated. Similarly, new technologies, such as distributed generation and battery storage, could result in certain distribution assets becoming redundant and no longer economical to operate. Electric distribution and distribution assets will need to be upgraded or reconfigured in order to incorporate changes to generation and to usage as electrification of transportation and space heating changes the needs of the system. These factors could also result in retirements earlier than might be otherwise expected. Additionally, in response to wildfires, PG&E plans to replace assets at a greater pace than is incorporated in the historical data. All of these factors will impact PG&E's assets in the future in a different manner than has been the case in the past and all of these factors have the potential to result in the retirement of existing assets earlier than has been experienced historically.

Simply put, we should reasonably expect that the future of both the electric and gas industries will be different than the past. In the aggregate, the combination of these factors should result in higher levels of retirements in the future than has occurred in the past, both because aging infrastructure will need to be replaced and because technological, environmental and regulatory changes create the risk that it will not be economical to operate portions of PG&E's electric or gas systems or that existing assets will be replaced earlier than anticipated. The net effect on service lives is two-fold: (1) PG&E's service lives for many assets should be expected to be shorter in the future than has been experienced in the past; and (2) the Commission's prior recognition of the importance of gradualism when

---

[119] See Exhibit (PG&E-10) (Feb. 28, 2022), p. 12-24 to p. 12-42; also see Section B.2 of this rebuttal testimony.

increasing service lives, particularly as it relates to increasing service lives, has even more importance considering these changing conditions. Cal Advocates and TURN witness Garrett have not adequately incorporated either of these factors into their service life estimates.

Q 86 Have you incorporated these concepts into your recommendations?

A 86 Yes, I have considered these concepts. However, I have not significantly shortened service lives from what has been proposed in previous depreciation studies or from the statistical indications from PG&E's historical data. Thus, while these factors have impacted my estimates, I have been relatively moderate in the application of judgment as far as how the future will differ from past experience with regard to service lives.[120] As a result, based on information available today, I believe that my estimates are more representative of the upper range of reasonableness for PG&E's service lives and that for several asset classes shorter service lives than I recommend may be most appropriate. Further increases in service lives, such as proposed by TURN and to a lesser extent by Cal Advocates, would not be appropriate and instead create the risk of not recovering the Company's costs over the service lives of its assets.

d. TURN Ignores PG&E's Extensive Historical Data and Bases Estimates on Too Short of a Historical Period

Q 87 In addition to the factors discussed in the previous sections, what is the primary difference between your estimates and those of TURN?

A 87 The other primary difference with regard to the statistical life analysis is that TURN witness Garrett has only relied on 22 years of historical data. In contrast, I have incorporated many more decades of data, which allows for the study of a full life cycle of the Company's assets and does not give undue consideration to recent events that may not be representative of the future.

Q 88 Why has Mr. Garrett elected to not use a longer period of historical data?

---

[120] I note here that the use of the UoP Method also addresses these issues for gas distribution assets. However, because both Cal Advocates and TURN do not recommend the use of UoP in this case, this puts even more importance on their unreasonable recommendations to increase service lives for gas distribution accounts.

A 88 Based on Mr. Garrett's testimony in this case (though, as I discuss, not necessarily in other cases), he disagrees with the use of statistically-aged data.[121] Prior to 1999, PG&E's available data was not aged data (meaning that the vintage year, and, therefore, the age of retirements was not known). Because the 22-year period since 1999 is a short period of time, at least relative to the service lives of the Company's assets, older data were statistically aged to assign vintage years to data prior to 1999 in order to be included in the depreciation study. This allows for the study of a longer and more robust period of history. Statistically aged data is widely used in the industry and it is generally understood that having a longer period of history can provide value to the historical life analysis.

Q 89 Is the use of statistically aged data supported by depreciation authorities?

A 89 Yes. NARUC explains on p. 106 of *Public Utility Depreciation Practices* that:

> [I]f the decision has been made to keep aged records from the present forward, the STAGE model [statistically aging] may be used to simulate aged data for the preceding years.

Thus, NARUC supports the practice used in the depreciation study.

Q 90 Please explain further how statistically aged data were incorporated into the depreciation study.

A 90 Due to the types of data that were available, there were essentially two choices for performing the study:

1) Use only the recorded aged data. This would mean only using data recorded in the 22 years from 1999 through 2020; or
2) Use the recorded aged data and use statistically aged data prior to 1999. The retirements in the statistically aged data are PG&E's recorded retirements, but vintages are assigned to the retirements based on Commission approved Iowa survivor curve types.

The disadvantage of the first approach is that it only incorporates 22 years of data. PG&E's assets have average service lives of 40 years or more, and some assets will live close to twice as long as the average. Using the first approach means we would only have data for less than half the ASL of many of PG&E's accounts and for only about a quarter or less of

---

[121] TURN-18, pp. 15-17.

the full life cycle for a group of assets. As a result, there is limited historical activity for any vintage year of plant, and the data provides much less than a complete historical picture of the survivor characteristics of the Company's assets. Further, any unusual events in the past 22 years are given undue consideration if only 22 years of data is studied. Indeed, the time since 1999 has seen the California electricity crisis, the Great Recession and the COVID-19 pandemic. These types of events have been relatively uncommon over the course of PG&E's history and can have undue influence on the statistical analysis if only 22 years of data are used. Thus, while Mr. Garrett argues that the advantage of this approach is that only aged data is used (and not statistically aged data),[122] in my judgment the disadvantages of Mr. Garrett's approach outweigh any perceived advantage.

In contrast, while using statistically aged data does involve estimation of the vintage years of retirements, this possible disadvantage is not sufficient to ignore such a large portion of PG&E's recorded history. Further, this shortcoming is mitigated by: (1) using PG&E's actual recorded retirements and (2) using Commission-approved Iowa type survivor curves for the statistical aging process.

In summary, in my judgment option (2) from above provides the best approach for analyzing PG&E's data. Mr. Garrett's decision to effectively ignore the statistically aged data limits his analysis to too short of a period of time to develop an understanding of the full life cycle of PG&E's assets. It is not prudent life analysis practice to completely ignore large periods of recorded company data as Mr. Garrett is doing with his life analysis.

Q 91 Is this the first case in which PG&E has proposed to use statistically-aged data?

A 91 No. PG&E used the same statistically aged data in PG&E's 2017 GRC and PG&E's 2020 GRC.

Q 92 Has TURN relied on statistically-aged data when developing survivor curve estimates for the Commission in a prior case?

A 92 Yes, in PG&E's 2017 GRC. Rather than challenge the use of statistically aged data, TURN used the statistically aged data in the 2017 GRC for its

---

[122] TURN-18, pp. 15-17.

statistical life analysis.[123] The statistically aged data has also been used by PG&E and Cal Advocates in each depreciation study since the 2017 GRC.

Q 93 Has Mr. Garrett based his service life estimates on statistically aged data in any other jurisdictions?

A 93 Yes. IN 2020, for Boston Gas Company (doing business as National Grid) in D.P.U. 20-120 Mr. Garrett based his service life estimates on a data set that, for some accounts, included over 30 years of statistically aged data.[124] Surprisingly, Mr. Garrett appears to be unaware that he did so,[125] even though TURN cites to this case in testimony[126] and my testimony in the Boston Gas Company case explained that statistically aged data were used.[127] Mr. Garrett did not challenge the use of statistically aged data in that case and did not refer to the statistically-aged data in that case as "manufactured data." I also note that the statistically aged data in the Boston Gas Company case displayed patterns indicating longer service life characteristics (and thus lower depreciation expense) for some of the larger accounts than the indications when only recorded aged data were used.[128] In the current case, using only the recorded data has the opposite effect. Mr. Garrett's arguments presented in the instant case should, therefore, be given minimal consideration.

Q 94 Mr. Garrett accuses Gannett Fleming of "manufacturing its own historical data in this case."[129] Please address this allegation.

A 94 This statement is patently incorrect. Mr. Garrett repeatedly uses the term "manufactured" or "manufacturing" when discussing the statistically-aged data. Either Mr. Garrett does not understand the statistical aging

---

123 See for example, A.15-09-001, TURN-11, Exhibit (JSG-3), p. 19, referencing Exhibit JSG-4 (TURN-11-Atch1) in which TURN's witness uses an experience band from 1909-2014, which includes statistically-aged data.

124 See Mr. Garrett's testimony in Mass.D.P.U. 20-120; also see, Mass. D.P.U. 20-120, Exhibit NG-NWA-1, p. 7.

125 See TURN's response to PG&E Data Request PGE_TURN006-Q01, dated 6/27/22 in Appendix A, at the end of this exhibit.

126 See TURN-18, p. 99.

127 See Mass. D.P.U. 20-120, Exhibit NG-NWA-1 in, p. 7–.

128 See Mass. D.P.U. 20-120, Exhibit NG-NWA-Rebuttal-1, p. 63.

129 TURN-18, p. 16, lines 6-7.

process[130] or he attempts to use provocative language to persuade the Commission to ignore what is an appropriate and accepted technique because he does not like the results. This attempt becomes more apparent when considering that Mr. Garrett made estimates based on statistically aged data for Boston Gas Company in which the use of statistically-aged data supported longer service lives and lower depreciation.

Mr. Garrett also acknowledged in discovery that he is not aware of the terms "manufactured" or "manufacturing" being used to describe statistical aging in any depreciation textbook.[131] As noted above, depreciation textbooks support that statistical aging as an appropriate approach for periods of time in which aged data is not available. Accordingly, the Commission should ignore Mr. Garrett's repeated usage of the terms "manufactured" or "manufacturing," as these terms are neither accurate nor relevant to assessing the use of statistically-aged data.

Q 95 Why is Mr. Garrett incorrect to state that Gannett Fleming has manufactured its own data?

A 95 There are multiple reasons why this statement is incorrect. The first is that, contrary to Mr. Garrett's claims,[132] the statistically aged data is PG&E's recorded data and was not created by Gannett Fleming. PG&E has maintained recorded data, including retirements, for the years prior to 1999 and these data were used in many prior depreciation studies.[133] The only

---

130 Based on his response to PG&E Data Request PGE_TURN006-Q03, dated 6/27/22, in Appendix A, at the end of this exhibit, it is possible that Mr. Garrett is unaware of how the statistical aging process was performed.

131 See TURN's response to PG&E Data Request PGE_TURN006-Q03, dated 6/27/22 in Appendix A, at the end of this exhibit. He also appears unaware that the concept of statistical aging is discussed in any textbook.

132 TURN-18, p. 16, lines 7-21.

133 For example, PG&E used the Simulated Plant Record (SPR) Method to determine survivor curves (and average service lives) for at least the 2007, 2011, and 2014 GRCs. The simulated balance method (like the statistical aging process) has been used in California for years for which the retirement of property by age (vintage) is not known. The SPR method, like the method I used in this case, requires a record of vintage plant additions and year end plant balances which were available for years prior to 1999. The Commission has repeatedly adopted survivor curves and lives based on the SPR method (whether those proposed by PG&E or by other parties). The Commission should therefore reject TURN's argument in this GRC that such data (and the statistical analysis of such data) should now be disregarded.

difference between the pre-1999 data and the data since 1999 is that recorded vintage years are not available for the pre-1999 data. As a result, it is only the vintage years that need to be estimated with the statistical aging process, not the recorded retirement amounts. However, this does not change the fact that the data is PG&E's recorded data or that the same unaged data was used for every depreciation study for PG&E prior to the 2017 GRC.

The second is that the data is not manufactured by Gannett Fleming in any way. The term "manufactured" implies that no data existed, and that Gannett Fleming simply created the statistically aged data. Nothing could be further from the truth. The recorded retirements in the statistically aged data are the retirement amounts recorded on PG&E's books. The only change to the data is that vintage years have been assigned. Further, while the aging process requires the selection of an Iowa curve type (e.g., R2, S1, etc.), as noted above, for the process of aging PG&E's data the curve types selected were those that were approved by the Commission in PG&E's 2014 GRC. Thus, when the data was statistically aged neither Gannett Fleming nor PG&E incorporated any additional judgment of how the data was to be aged. The inputs to the statistical aging program are the recorded (unaged) data and the Iowa curve types. The former was recorded on PG&E's books and the latter was approved by the Commission.

Q 96 Mr. Garrett argues that using statistically aged data "was not necessary in this case"[134] and that the Company's aged data is "more than sufficient."[135] Please address this assertion.

A 96 Mr. Garrett appears to argue that because the original life tables (OLT) based on the 1999-2020 experience band[136] (i.e., those that only include aged data) have data points that extend to a relatively small percent

---

134 TURN-18, p. 16, lines 20-21.

135 TURN-18, p. 30, lines 5-6.

136 The graph shown TURN-18 (for example, on page 26, Figure 3), do not specific the experience band, which makes it more difficult to understand and interpret the graphs. However, a comparison to the graphs provided in the workpapers supporting Exhibit (PG&E-10) (Feb. 28, 2022), Ch. 12 and in Section C.3.e of this rebuttal testimony shows that Mr. Garrett's graphs display the 1999-2020 experience band but not the overall experience band.

surviving, the aged data alone is sufficient to be used for the study and there is no need to use a longer period of recorded history. The problem with Mr. Garrett's argument is that it represents a fundamental misunderstanding of how life tables are developed. While a life table based on the 1999-2020 experience band may decline to a low percent surviving, the calculations to develop this life table only incorporate 22 years of activity. This means both that only 22 years of experience are available for any single vintage year and that each individual data point is only based on the data for 22 years of retirements. I would prefer to incorporate a longer period of history and, as a result, believe it is insufficient to only rely on the recorded aged data.

Q 97 Do any of the graphs presented in Mr. Garrett's testimony include the statistically-aged data?

A 97 No. His graphs only include the 1999-2020 experience band. Thus, while his graphs may appear to show PG&E's estimate as a poor fit of the data, this is typically because they do not include the statistically aged data. In the graphs provided in Exhibit (PG&E-10), Chapter 12 workpapers, and the graphs provided in this testimony, I have generally shown both the overall band and the 1999-2020 experience band. This allows the Commission to review more of the information that should be considered than Mr. Garrett's presentation. For these reasons the graphs in my testimony and workpapers provide a much better illustration of how the recommended survivor curves fit the historical data.

e. Account-By-Account Discussion

1) Accounts 353.02 and 353.03, Station Equipment – Step-Up Transformers

Q 98 Please summarize the currently authorized and proposed estimates for this account.

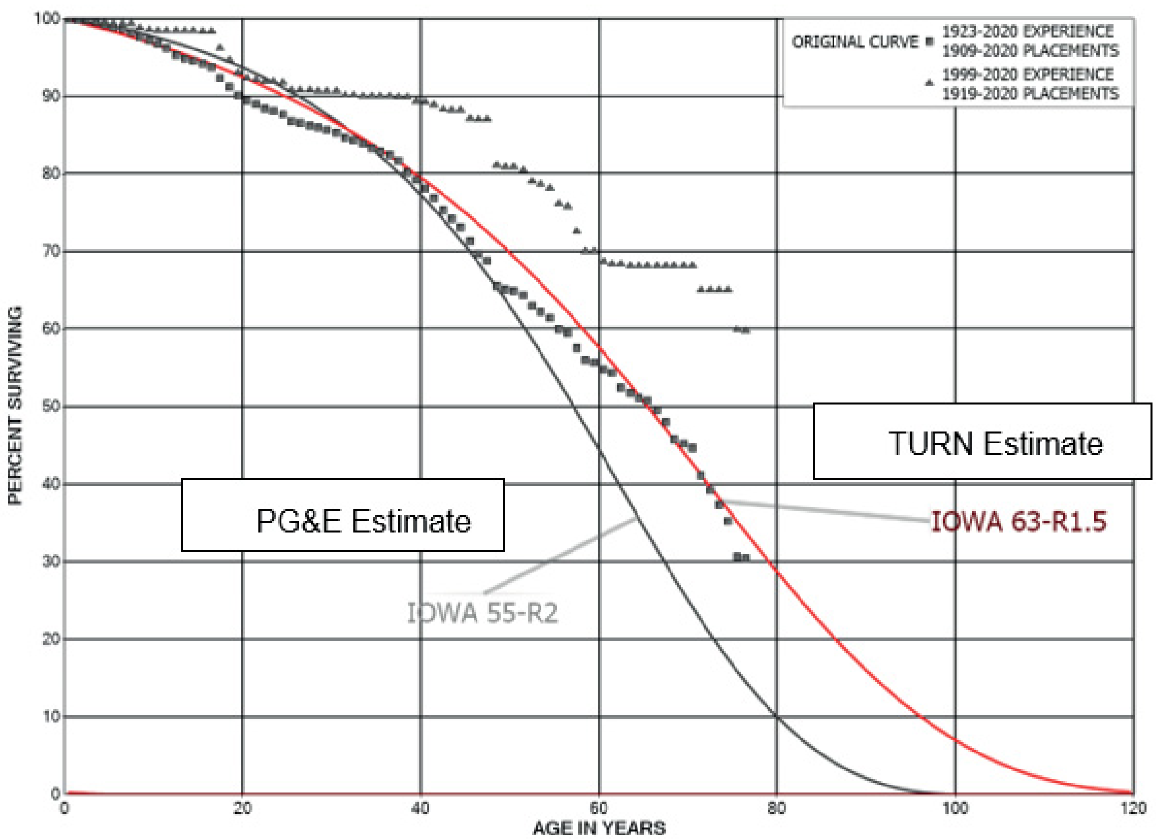
A 98 The currently authorized and proposed estimates for each party are summarized in the table below.

TABLE 12-3
COMPARISON OF CURRENTLY AUTHORIZED, PG&E, CAL ADVOCATES AND TURN SERVICE LIFE ESTIMATES FOR ACCOUNTS 353.02 AND 353.03, STATION EQUIPMENT – STEP-UP TRANSFORMERS

2020 GRC Authorized Estimate	PG&E Estimate	Cal Advocates Estimate	TURN Estimate
55-R1.5	55-R2	55-R2	63-R1.5

A graphical comparison of the estimates of each party is shown in Figure 12-9 below. The figure also shows both the overall band (shown as black squares), which includes the statistically-aged data, and the 1999-2020 experience band (shown as black triangles), which does not include the statistically aged data.

FIGURE 12-9
ACCOUNT 353.02 STATION EQUIPMENT – STEP-UP TRANSFORMERS ORIGINAL LIFE TABLES FOR OVERALL AND 1999-2020 EXPERIENCE BANDS AND ESTIMATED SMOOTH SURVIVOR CURVES



Q 99 What are the primary reasons for the differences between your proposals and TURN's for this account?

A 99 There are multiple reasons for the differences. The first is that PG&E has put greater emphasis on data through about age 50, which, as I will discuss, is more appropriate for this account. The second reason is that, as discussed in Section C.3.b, TURN's approach to determining service lives incorporated minimal information other than the statistical analysis. For this account, there are factors that have changed over time that mean that the historical data, and particularly the experience for older ages, is not likely to be indicative of the future experience for much of the account. Further, based on Mr. Garrett's testimony,[137] he appears to be unfamiliar which assets are in this account. Finally, TURN's approach is inconsistent with the concept of gradualism, which I have discussed in more detail in Section C.1.e.

Q 100 What types of assets are in this account and what factors cause retirements of the assets in this account?

A 100 This account includes step-up transformers at the Company's generating facilities. Step-up transformers increase the voltage of electricity from a power station to transmission voltage prior to entering the switchyard and the transmission system. While retirements occur due to causes that also can cause substation transformers to be retired, such as failure or proactive replacement, retirements also occur due the retirement of the generating facility. That is, step-up transformers should not be expected to outlive the related generating facilities.

Q 101 How do these factors influence the service lives of the assets in the account?

A 101 PG&E's step-up transformers are located at its production facilities (nuclear assets are in a different asset class). While many hydro older facilities have been in service for many decades, newer facilities typically have shorter life spans than, for example, hydro facilities constructed in the early 1900s. This will limit the overall life of many of the assets in these accounts and result in shorter lives, overall, for newer assets in the account. Further, the

[137] See TURN-18, p. 25, lines 3-10.

experience of newer assets in the account will be different from those of older assets. While some step-up transformers at older powerhouses that are run infrequently may have remained in service for many years, the same will not be true at newer generating facilities (including larger hydro facilities such as the Helms Pumped Storage facility) which are run more frequently. Additionally, factors discussed in Section C.3.c could impact hydro assets and the related step-up transformers, resulting in more retirements in the future than has historically occurred. The combination of all these factors both means that the future experience for this account may be different from the past. It also provides reason to focus more on earlier ages when curve fitting, which as discussed above was the approach used in the statistical analysis for this account in PG&E's depreciation study.

Q 102 Has your experience meeting with PG&E personnel and touring PG&E's facilities helped to inform your judgment for this account?

A 102 Yes. This account helps to demonstrate why meeting with PG&E SMEs and conducting site visits is important for a depreciation study. As an example, I have toured newer combined cycle facilities, newer hydro facilities, and very old hydro facilities and observed the differences in step-up transformers between the different sites. I have also observed older transformers at older, less frequently operated hydro facilities, which informed that the historical data would include the experience of older types of assets that are not reflective of most of the investment in this account. In total, this knowledge helps to inform my judgment and supports my estimate over that of Mr. Garrett.

Q 103 Is TURN's proposal to increase the service life for this account reasonable?

A 103 No. For the reasons discussed above, it is not appropriate to increase the life for this account. Further, the ASL authorized in the 2017 GRC was a 12-year increase from the 2014 GRC.[138] TURN's estimate increases the ASL estimate by another eight years, which would be a 20-year increase in the ASL from the 2014 GRC. This sort of increase is not characteristic of the concept of gradualism.

---

[138] See, A.15-09-001, Joint Motion for Adoption of Settlement Agreement (Aug. 3, 2016), Appendix C, Settlement Agreement (as ratified by D.17-05-013).

Q 104 Are there any additional issues with TURN's proposal?

A 104 Yes. For Account 353.03, which includes the step-up transformers for combined cycle plants, I have used a retirement date that corresponds with the retirement date for the related plants. This is reasonable because the step-up transformers are unlikely to remain in service once the plants are retired. This approach has also been used in several recent studies. TURN has, perhaps inadvertently, not used the retirement date for this account.

2) Account 362, Station Equipment

Q 105 Please summarize the currently authorized and proposed estimates for this account.

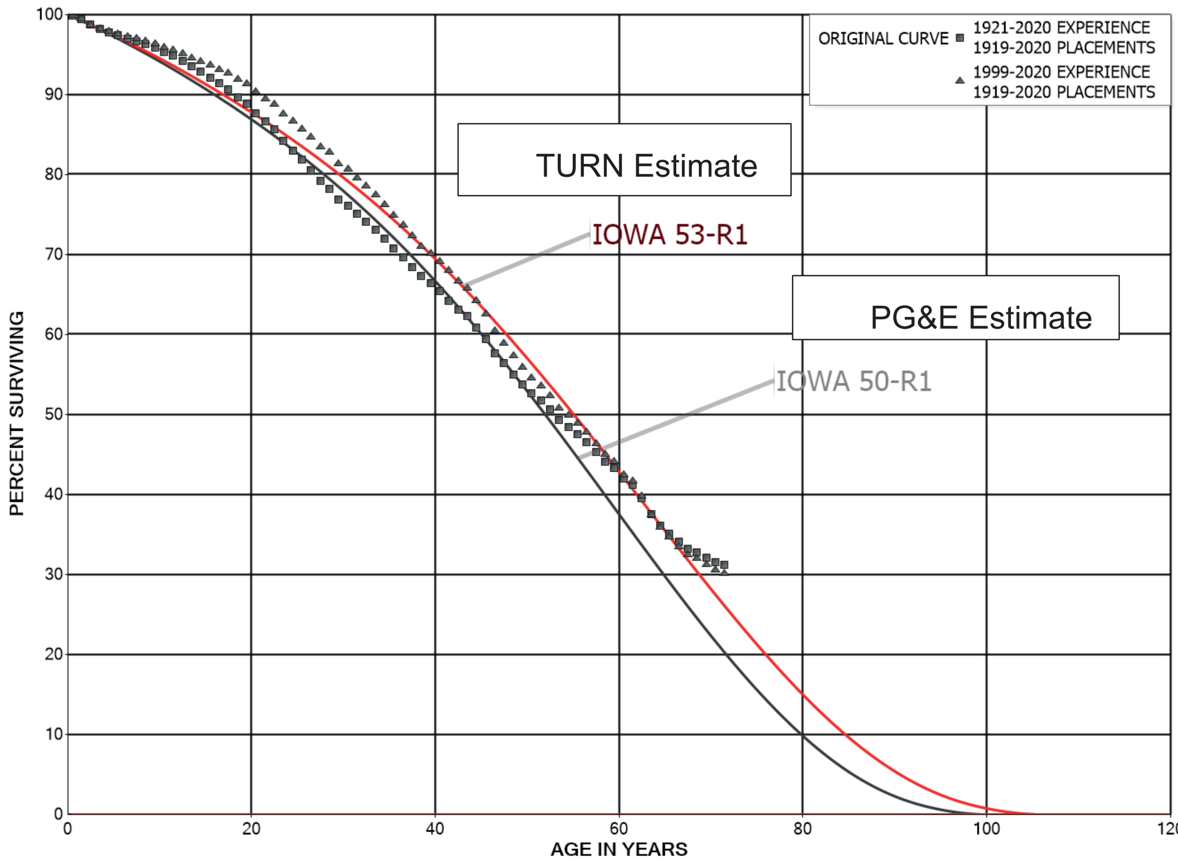
A 105 The currently authorized and proposed estimates for each party are summarized in the table below.

TABLE 12-4
COMPARISON OF CURRENTLY AUTHORIZED, PG&E, CAL ADVOCATES AND TURN SERVICE LIFE ESTIMATES FOR ACCOUNT 362, STATION EQUIPMENT

Line No	2020 GRC Authorized Estimate	PG&E Estimate	Cal Advocates Estimate	TURN Estimate
1	46-R1.5	50-R1	50-R1	53-R1

For a graphical comparison of the proposed estimates see Figure 12-10 below. The figure also shows both the overall experience band (shown as black squares), which includes the statistically-aged data, and the 1999-2020 experience band (shown as black triangles), which does not include the statistically-aged data.

FIGURE 12-10
ACCOUNT 362 STATION EQUIPMENT
ORIGINAL LIFE TABLES FOR OVERALL AND 1999-2020 EXPERIENCE BANDS AND ESTIMATED SMOOTH SURVIVOR CURVES



Q 106 Please explain the problems with TURN's proposal.

A 106 The issues with TURN's proposal are similar to those for most accounts. I have addressed the primary differences between TURN's approach and mine in Sections C.3.b and C.3.d. As can be seen in the graph above, PG&E's estimate is a better fit of the overall band (shown in black squares) than Mr. Garrett's estimate. Mr. Garrett's proposal is also not consistent with the concept of gradualism as it results in a 7-year increase in average service life. Finally, factors discussed in Section C.3.c are likely to affect this account as substation equipment will likely need to be replaced due to overall load growth and changes in the load profile resulting from Net Zero by 2045.

3) Account 364, Poles, Towers, and Fixtures

Q 107 Please summarize the currently authorized and proposed estimates for this account.

A 107 The currently authorized and proposed estimates for each party are summarized in the table below.

TABLE 12-5
COMPARISON OF CURRENTLY AUTHORIZED, PG&E, CAL ADVOCATES AND TURN SERVICE LIFE ESTIMATES FOR ACCOUNT 364, POLES, TOWERS AND FIXTURES

Line No.	2020 GRC Authorized Estimate	PG&E Estimate	Cal Advocates Estimate	TURN Estimate
1	44-R2	44-R2	47-R1.5	52-R2

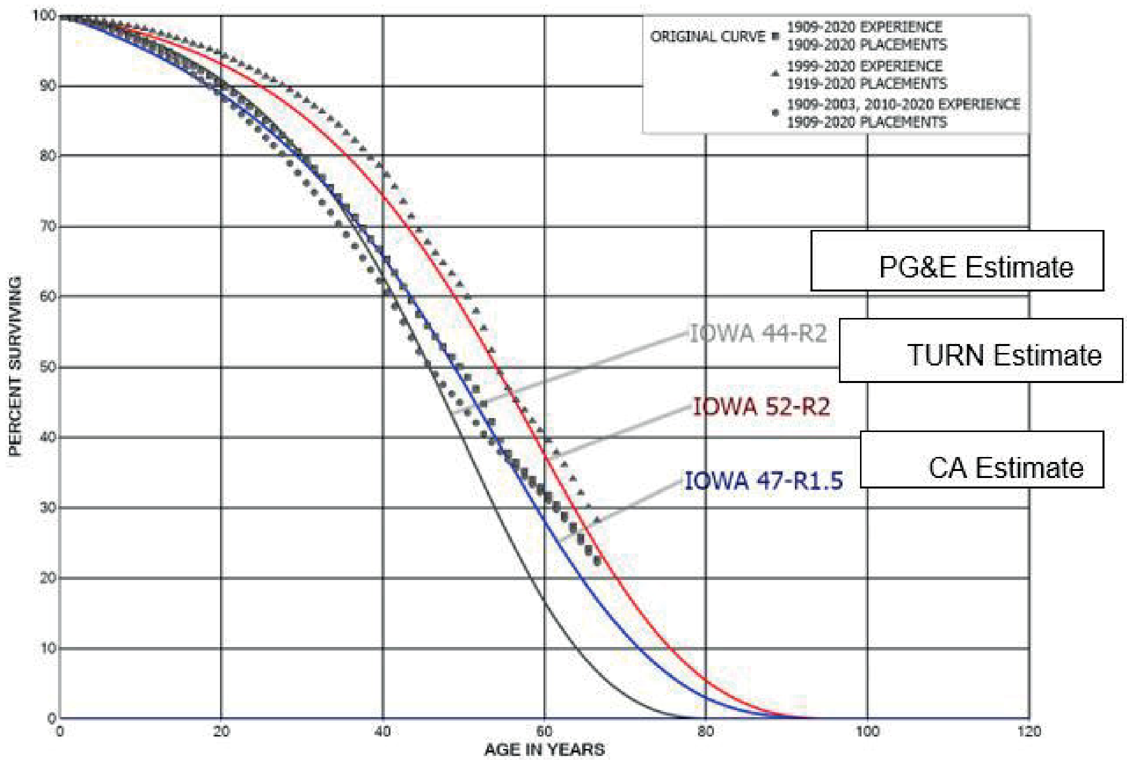
I note that, subsequent to the completion of the depreciation study, PG&E announced a plan to underground 10,000 miles of overhead electric lines.[139] I would expect that this plan will result in an overall shorter ASL for assets currently in service than has been experienced previously. Thus, the outlook for this account favors a shorter service life than was the case when I completed the depreciation study. Neither Cal Advocates nor TURN mentions this in their depreciation testimonies, nor do they appear to have incorporated the undergrounding plan into their estimates.

For a graphical comparison of the proposed estimates see Figure 12-11 below. The figure also shows both the overall band (shown as black squares), which includes the statistically aged data, and the 1999-2020 experience band (shown as black triangles), which does not include the statistically-aged data.

---

[139] Undergrounding electric overhead lines, <https://www.pge.com/en_US/residential/customer-service/other-services/electric-undergrounding-program/electric-undergrounding-program.page> (as of July 4, 2022).

FIGURE 12-11
ACCOUNT 364 POLES, TOWERS AND FIXTURES
ORIGINAL LIFE TABLES FOR OVERALL AND 1999-2020 EXPERIENCE BANDS AND ESTIMATED SMOOTH SURVIVOR CURVES



Q 108 Please explain why you disagree with TURN's proposal for this account.

A 108 Most of the issues with TURN's proposal are similar to those for accounts discussed previously. However, few accounts illustrate Mr. Garrett's lack of concern with developing a reasonable service life than this account. Despite that the Company has announced a plan to underground 10,000 miles of overhead lines, which means retiring the poles on the affected lines, TURN proposes to increase the average service life by eight years. This is the exact opposite direction of what we should expect given the scope of the undergrounding program (as well as other resilience and reliability programs). Further, even if undergrounding occurs at a lesser scale than anticipated by PG&E, there is still a need to harden the system, which will result in faster replacements of assets than in the past. Additionally, the path to Net Zero by 2045 will likely result in upgrades to distribution lines to reliability provide service with an increased and changing load profile.

In addition to this aspect of TURN's proposal, I have addressed the use of statistically-aged data and the need for informed judgment previously in Sections C.3.b and C.3.d. As can be seen in the graph above, PG&E's estimate is a better fit of the overall band (shown in black squares) than Mr. Garrett's estimate. Each of these factors support the concept of gradualism and, if anything, supports a shorter service life than recommended by PG&E. Mr. Garrett's proposal is not consistent with the concept of gradualism as his recommendation increases the average service life by eight years.

Q 109 Please explain why you disagree with Cal Advocate's proposal for this account.

A 109 The issues with Cal Advocates' estimate for this account are similar to those discussed with TURN's estimate. Given the factors discussed above, it is not reasonable to increase the life for this account.

4) Account 365, Overhead Conductors and Devices

Q 110 Please summarize the currently authorized and proposed estimates for this account.

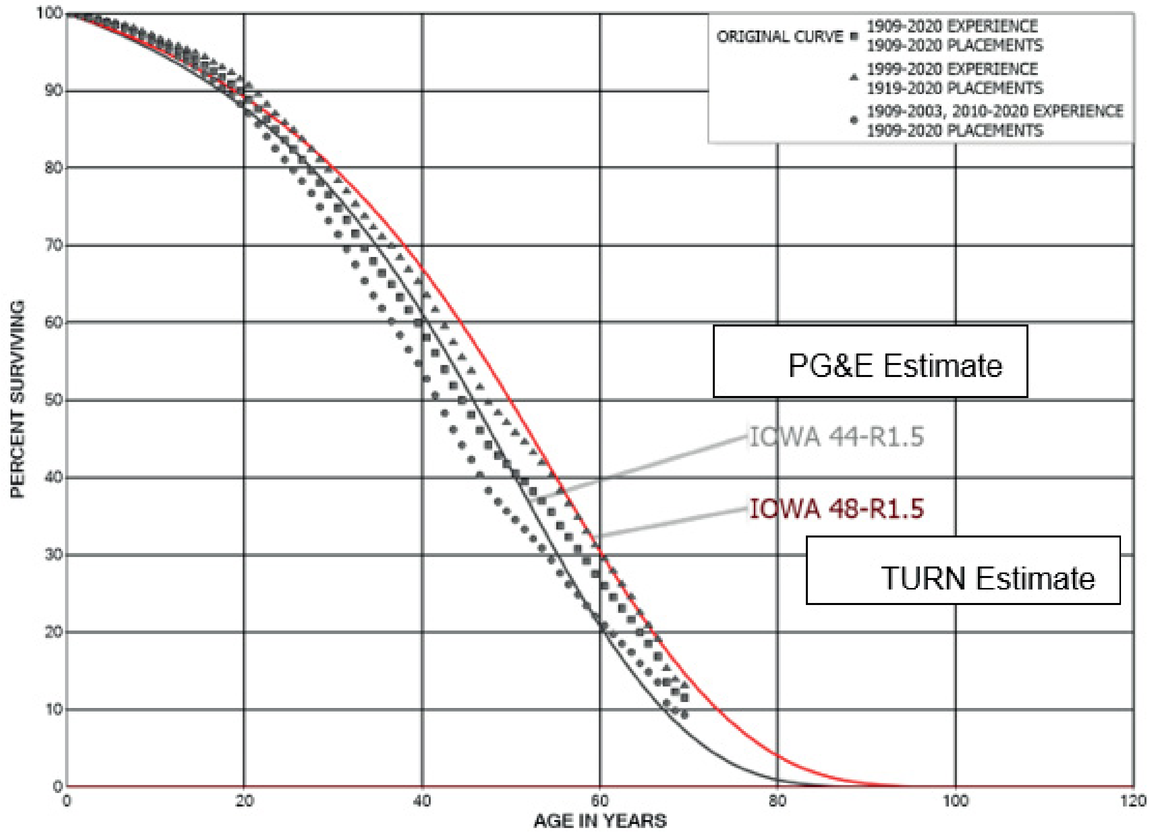
A 110 The currently authorized and proposed estimates for each party are summarized in the table below.

TABLE 12-6
COMPARISON OF CURRENTLY AUTHORIZED, PG&E, CAL ADVOCATES AND TURN SERVICE LIFE ESTIMATES FOR ACCOUNT 365, OVERHEAD CONDUCTORS AND DEVICES

Line No.	2020 GRC Authorized Estimate	PG&E Estimate	Cal Advocates Estimate	TURN Estimate
1	46-R2	44-R1.5	44-R1.5	48-R1.5

For a graphical comparison of the proposed estimates see Figure 12-12 below. The figure also shows both the overall band (shown as black squares), which includes the statistically-aged data, and the 1999-2020 experience band (shown as black triangles), which does not include the statistically-aged data. As can be seen in the graph, while PG&E's estimate is a good fit of the overall band, TURN's estimate does not fit any band particularly well.

FIGURE 12-12
ACCOUNT 365 OVERHEAD CONDUCTORS AND DEVICES
ORIGINAL LIFE TABLES FOR OVERALL AND 1999-2020 EXPERIENCE BANDS AND ESTIMATED SMOOTH SURVIVOR CURVES



Q 111 Are the issues with TURN's proposals for this account similar to those of other accounts?

A 111 Yes. The primary issues have been addressed previously, such as gradualism (Section C.1.e), the use of statistically aged data (Section C.3.d) and the importance of judgment and other factors that will impact PG&E's service lives (Section C.3.c). As can be seen in Figure 12-12 above, TURN's proposal is (by virtue of being above almost all data points on the graph) for a longer service life than experienced in any of the bands shown in the graph (including the 1999-2020 band that only includes recorded aged data). However, Similar to Account 364, this account will be affected by the undergrounding program, other system hardening and reliability initiatives, and the impacts of Net Zero by 2045. TURN's proposal to increase the service life beyond what even the data shows is inconsistent with reasonable expectations for this account.

5) Account 367, Underground Conductors and Devices

Q 112 Please summarize the currently authorized and proposed estimates for this account.

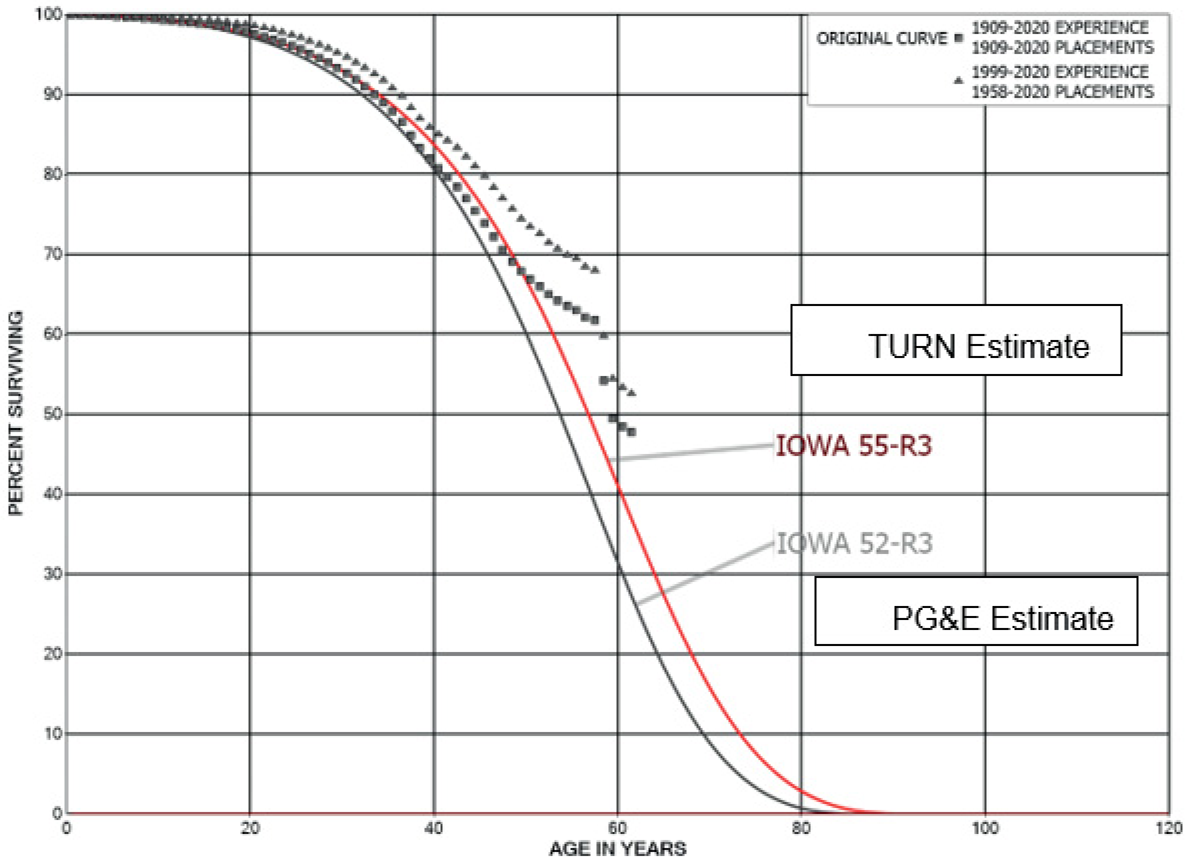
A 112 The currently authorized and proposed estimates for each party are summarized in the table below.

TABLE 12-7
COMPARISON OF CURRENTLY AUTHORIZED, PG&E, CAL ADVOCATES AND TURN SERVICE LIFE ESTIMATES FOR ACCOUNT 367, UNDERGROUND CONDUCTORS AND DEVICES

Line No.	2020 GRC Authorized Estimate	PG&E Estimate	Cal Advocates Estimate	TURN Estimate
1	50-R3	52-R3	52-R3	55-R3

For a graphical comparison of the proposed estimates see Figure 12-13 below. The figure also shows the overall band (shown as black squares), which includes the statistically-aged data, and the 1999-2020 experience band (shown as black triangles), which does not include the statistically-aged data. As can be seen in the graph, while PG&E's estimate is a good fit of the overall band, and is a gradual increase to the current service life while TURN's estimate represents too long of a service life when compared to the current estimate and the data.

FIGURE 12-13
ACCOUNT 367 UNDERGROUND CONDUCTORS AND DEVICES
ORIGINAL LIFE TABLES FOR OVERALL AND 1999-2020 EXPERIENCE BANDS AND ESTIMATED SMOOTH SURVIVOR CURVES



Q 113 What support does Mr. Garrett provide for his proposal?

A 113 Mr. Garrett provides limited discussion on this account.[140] The primary difference is that similar to most other accounts, he relies more heavily on the 1999-2020 experience band when estimating a survivor curve, as opposed to the longer period of data available. I have addressed this concept in Section C.3.d.

Q 114 Are there any other factors that support PG&E's estimate is more reasonable than TURN's?

A 114 Yes. The concept of gradualism supports PG&E's estimate instead of TURN's. As shown in Table 12-2 above, Mr. Garrett proposes an eight-year increase in ASL over the authorized estimate from the 2017 GRC.

---

[140] TURN-18, p. 31, line 1 to p. 33, line 12.

Increasing an ASL estimate that much in a six-year time span is not consistent with the concept of gradualism. For that reason and the reason discussed above, TURN's estimate should not be approved for this account.

6) Account 368.01, Line Transformers – Overhead

Q 115 Please summarize the currently authorized and proposed estimates for this account.

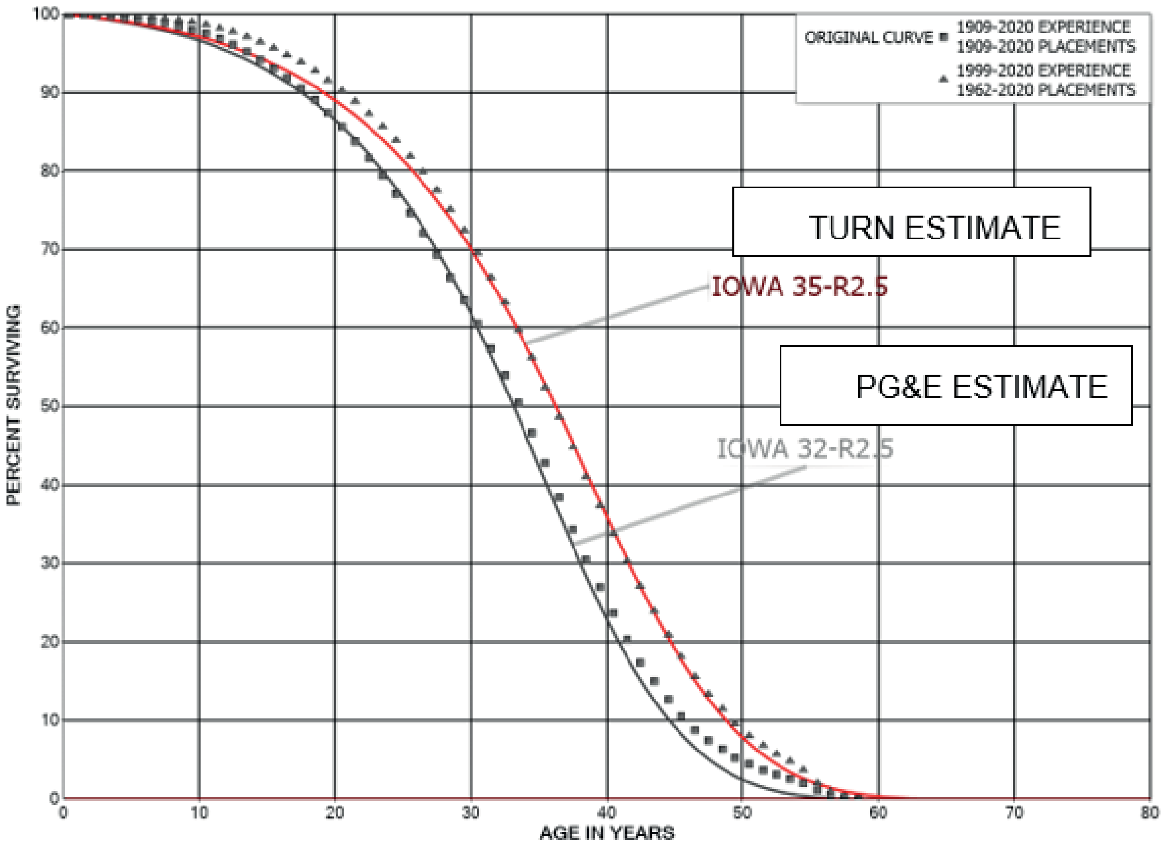
A 115 The currently authorized and proposed estimates for each party are summarized in the table below.

TABLE 12-8
COMPARISON OF CURRENTLY AUTHORIZED, PG&E, CAL ADVOCATES AND TURN SERVICE LIFE ESTIMATES FOR ACCOUNT 368.01, LINE TRANSFORMERS - OVERHEAD

Line No.	2020 GRC Authorized Estimate	PG&E Estimate	Cal Advocates Estimate	TURN Estimate
1	32-R2.5	32-R2.5	32-R2.5	35-R2.5

For a graphical comparison of the proposed estimates see Figure 12-14 below. The figure also shows both the overall band (shown as black squares), which includes the statistically aged data, and the 1999-2020 experience band (shown as black triangles), which does not include the statistically aged data. As can be seen in the graph, while PG&E's estimate is a very good fit of the overall band, TURN's estimate has a much longer life than the overall data band suggests.

FIGURE 12-14
ACCOUNT 368.01 LINE TRANSFORMERS - OVERHEAD
ORIGINAL LIFE TABLES FOR OVERALL AND 1999-2020 EXPERIENCE BANDS AND ESTIMATED SMOOTH SURVIVOR CURVES



Q 116 Are the issues with Mr. Garrett’s proposal for this account similar to the other accounts?

A 116 Yes. As with other accounts, the issues discussed in Sections C.3.b, C.3.c, and C.3.d also apply to this account.

7) Account 368.02, Line Transformers – Underground

Q 117 Please summarize the currently authorized and proposed estimates for this account.

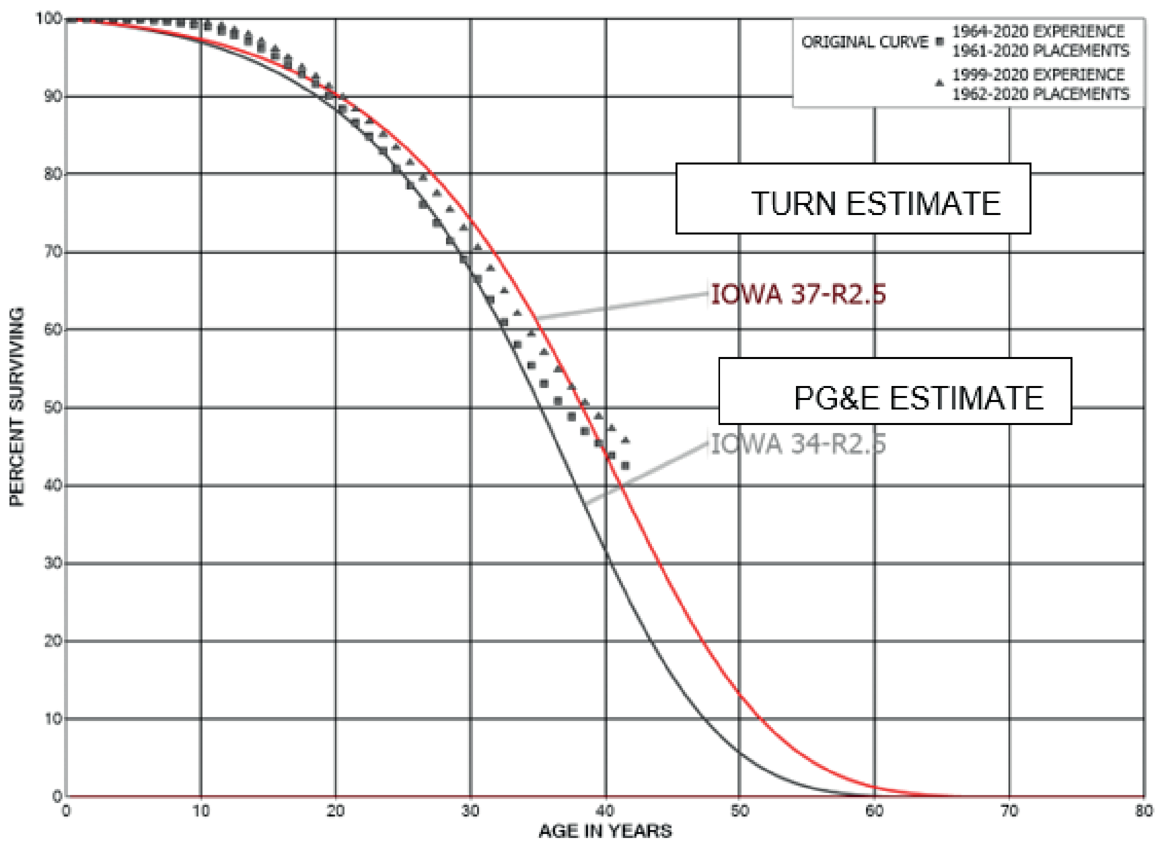
A 117 The currently authorized and proposed estimates for each party are summarized in the table below.

TABLE 12-9
COMPARISON OF CURRENTLY AUTHORIZED, PG&E, CAL ADVOCATES AND TURN SERVICE LIFE ESTIMATES FOR ACCOUNT 368.02, LINE TRANSFORMERS - UNDERGROUND

Line No.	2020 GRC Authorized Estimate	PG&E Estimate	Cal Advocates Estimate	TURN Estimate
1	33-R2.5	34-R2.5	34-R2.5	37-R2.5

For a graphical comparison of the proposed estimates see Figure 12-15 below. The figure also shows both the overall band (shown as black squares), which includes the statistically aged data, and the 1999-2020 experience band (shown as black triangles), which does not include the statistically aged data. As can be seen in the graph, while PG&E's estimate is a very good fit of the overall band, while TURN's estimate has a much longer life than the overall data band suggests.

FIGURE 12-15
ACCOUNT 368.02 LINE TRANSFORMERS - UNDERGROUND
ORIGINAL LIFE TABLES FOR OVERALL AND 1999-2020 EXPERIENCE BANDS AND ESTIMATED SMOOTH SURVIVOR CURVES



Q 118 Are the issues with Mr. Garrett's proposal for this account similar to the other accounts?

A 118 Yes. As with other accounts, the issues discussed in Sections C.3.b, C.3.c, and C.3.d also apply to this account. As with prior accounts, Mr. Garrett ignores the overall data band and choosing to only fit his survivor curve to the 1999-2020 experience band.

8) Account 369.01, Services – Overhead

Q 119 Please summarize the currently authorized and proposed estimates for this account.

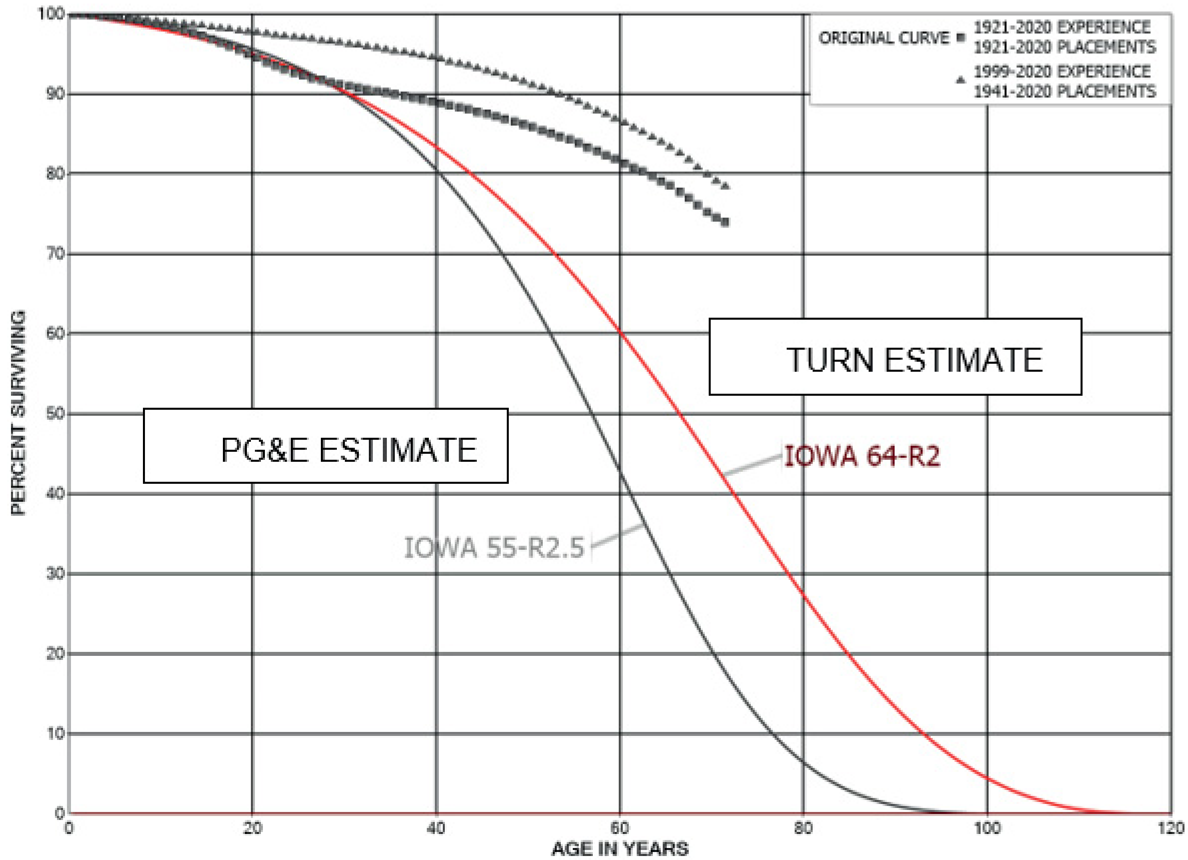
A 119 The currently authorized and proposed estimates for each party are summarized in the table below.

TABLE 12-10
COMPARISON OF CURRENTLY AUTHORIZED, PG&E, CAL ADVOCATES AND TURN SERVICE LIFE ESTIMATES FOR ACCOUNT 369.01, SERVICES - OVERHEAD

Line No.	2020 GRC Authorized Estimate	PG&E Estimate	Cal Advocates Estimate	TURN Estimate
1	52-R2.5	55-R2.5	55-R2.5	64-R2

Please see Figure 12-16 below for a comparison of the estimates. The figure also shows both the overall band (shown as black squares), which includes the statistically aged data, and the 1999-2020 experience band (shown as black triangles), which does not include the statistically aged data.

FIGURE 12-16
ACCOUNT 369.01 SERVICES – OVERHEAD
ORIGINAL LIFE TABLES FOR OVERALL AND 1999-2020 EXPERIENCE BANDS AND ESTIMATED SMOOTH SURVIVOR CURVES



Q 120 Do any of the proposals fit the data particularly well?

A 120 No. I would consider the statistical analysis to be inconclusive for this account. The data alone cannot distinguish between the proposed curves. My estimate better matches the earlier years of data (through about age 30) but the other parties are somewhat closer (but still not good fits) to later years. As a result, other factors, such as gradualism and those discussed in Section C.3.c should be considered.

Q 121 Does TURN provide any reasons for their proposal other than statistical curve fitting?

A 121 No. As a result, there is no compelling reasons to abandon the concept of gradualism that, as discussed in Section C.3.d, the Commission has previously supported. As can be seen in Table 12-2 above, TURN's proposal would result in an increase in the ASL of 12 years when compared to the 2017 GRC. This represents a fairly large increase in the ASL over a 6-year period of time.

Q 122 Are there any reasons to expect a shorter life for this account than experienced in the past?

A 122 Yes. Similar to other overhead distribution accounts, this account will be impacted by undergrounding.

9) Account 369.02, Services – Underground

Q 123 Please summarize the currently authorized and proposed estimates for this account.

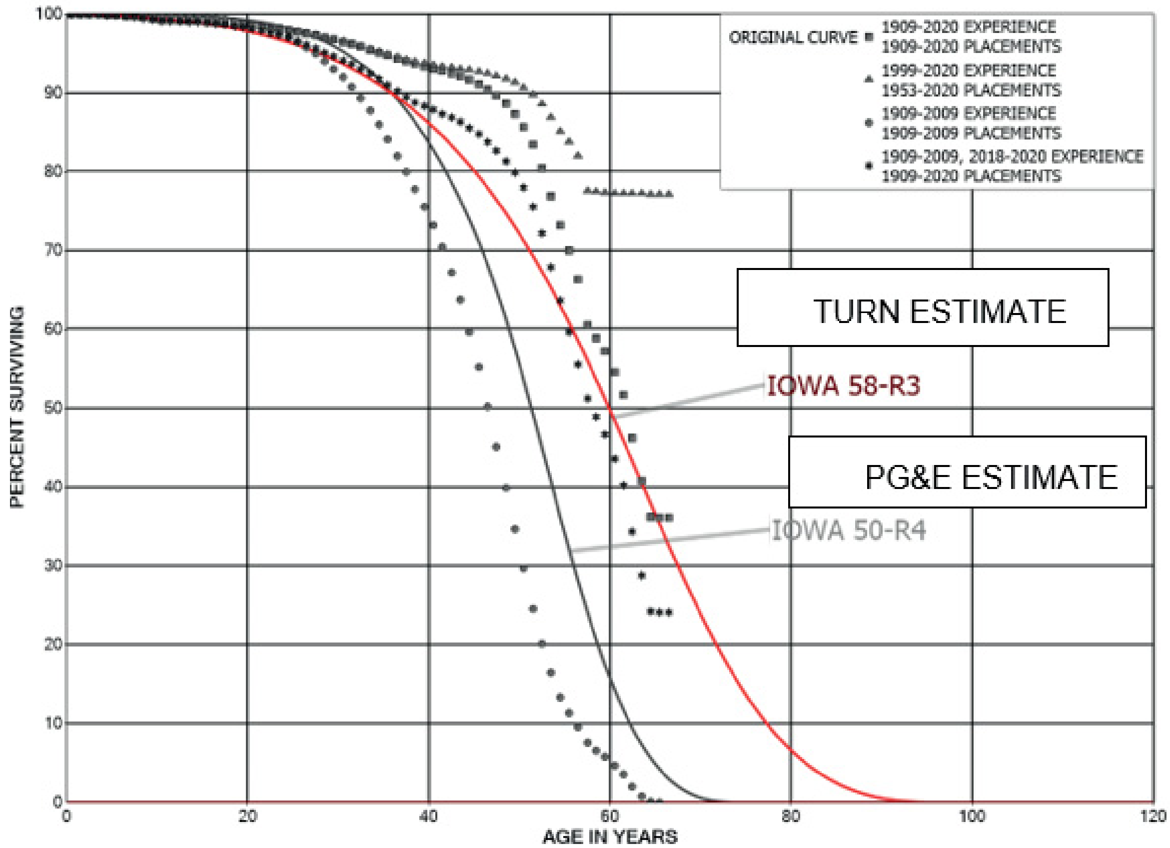
A 123 The currently authorized and proposed estimates for each party are summarized in the table below.

TABLE 12-11
COMPARISON OF CURRENTLY AUTHORIZED, PG&E, CAL ADVOCATES AND TURN SERVICE LIFE ESTIMATES FOR ACCOUNT 369.02, SERVICES - UNDERGROUND

Line No.	2020 GRC Authorized Estimate	PG&E Estimate	Cal Advocates Estimate	TURN Estimate
1	45-R4	50-R4	50-R4	58-R3

Figure 12-17 below provides a comparison of the proposed estimates. As discussed below, and in Sections C.3.b, C.3.c, and C.3.d, while the data could support a longer service life, a more gradual change is most appropriate.

FIGURE 12-17
ACCOUNT 369.02 SERVICES – UNDERGROUND
ORIGINAL LIFE TABLES FOR OVERALL AND 1999-2020 EXPERIENCE BANDS AND ESTIMATED SMOOTH SURVIVOR CURVES



Q 124 Are the issues for this account similar to those of other accounts?

A 124 Yes. TURN provides no evidence other than curve matching to the shorter 1999-2020 experience band.[141] TURN's proposal is again inconsistent with the concept of gradualism. For reasons discussed previously in my testimony and for other accounts, PG&E's proposal is most appropriate for this account.

10) Account 367, Mains

Q 125 Please summarize the currently authorized and proposed estimates for this account.

A 125 The currently authorized and proposed estimates for each party are summarized in the table below.

---

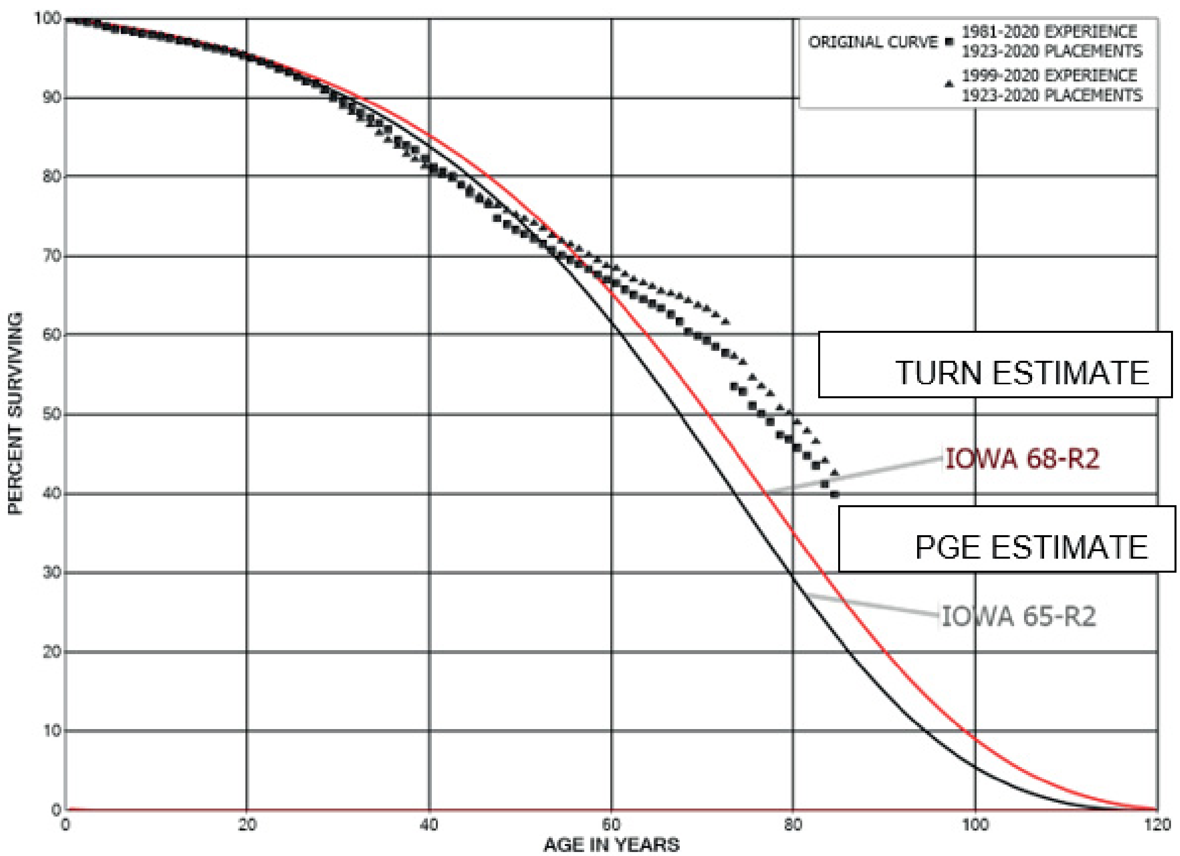
[141] TURN-18, p. 40.

TABLE 12-12
COMPARISON OF CURRENTLY AUTHORIZED, PG&E, CAL ADVOCATES AND TURN SERVICE LIFE ESTIMATES FOR ACCOUNT 367, MAINS

Line No.	2020 GRC Authorized Estimate	PG&E Estimate	Cal Advocates Estimate	TURN Estimate
1	66-R2	65-R2	65-R2	68-R2

Please see Figure 12-18 below for a comparison of the estimates proposed for this account. The chart includes the overall band (shown as black squares) and the 1999-2020 experience band (shown as black triangles).

FIGURE 12-18
ACCOUNT 367 MAINS
ORIGINAL LIFE TABLES FOR OVERALL AND 1999-2020 EXPERIENCE BANDS AND ESTIMATED SMOOTH SURVIVOR CURVES



Q 126 Does Mr. Garrett provide any support for his estimate other than the statistical results for the 1999-2020 experience band?

A 126 No.[142] Accordingly, the arguments I have made earlier in my testimony apply to this account as well.

Q 127 Please discuss Mr. Garrett's argument[143] that it is unnecessary to use statistically-aged data for this account.

A 127 The length of the "stub" OLT curve is not directly correlated to how many years of data are being analyzed. Even if the stub survivor curve extends to close to zero percent for the 1999-2020 band, it is still only based on 22 years of experience for any vintage. This is much less time than the 65-year ASL or the full life cycle of close to 100 years.

Q 128 Are there any other reasons why the service life should not be extended for this account?

A 128 Yes. As discussed throughout my testimony, achieving net zero emissions by 2045 will impact gas assets. It is unreasonable for TURN to increase the service life for this account given this context. If anything, we should expect a shorter service life than has been experienced in the past.

11) Account 376, Mains

Q 129 Please summarize the currently authorized and proposed estimates for this account.

A 129 The currently authorized and proposed estimates for each party are summarized in the table below.

TABLE 12-13
COMPARISON OF CURRENTLY AUTHORIZED, PG&E, CAL ADVOCATES AND TURN SERVICE LIFE ESTIMATES FOR ACCOUNT 376, MAINS

Line No	2020 GRC Authorized Estimate	PG&E Estimate	Cal Advocates Estimate	TURN Estimate
1	57-R3	57-R3	60-R3	57-R3

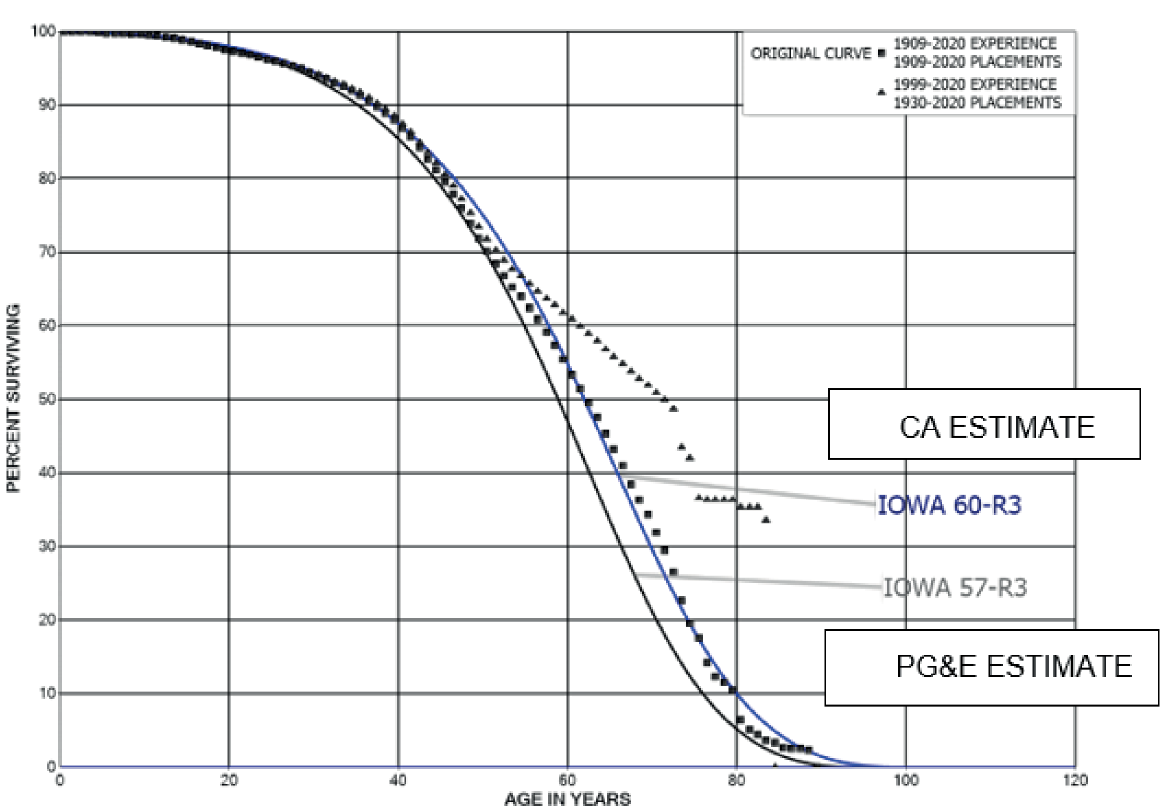
Please see Figure 12-19 below for a comparison of the estimates proposed for this account. The chart includes the overall band (shown as black squares) and the 1999-2020 experience band (shown as black triangles).

---

[142] TURN-18, pp. 42-43.

[143] TURN-18, p. 41, lines 9-10.

FIGURE 12-19
ACCOUNT 376 MAINS
ORIGINAL LIFE TABLES FOR OVERALL AND 1999-2020 EXPERIENCE BANDS AND ESTIMATED SMOOTH SURVIVOR CURVES



Q 130 Does Cal Advocates provide any support for their estimate?

A 130 Yes. Cal Advocates claims that their survivor curve “aligns more closely with the experience band 1909-2020.”[144]

Q 131 Do you believe that Cal Advocates estimate for this account is reasonable?

A 131 No, especially given the current environment in California related to decarbonization goals. As discussed throughout my testimony the Net Zero by 2045 goal will significantly affect the lives of gas assets. Increasing the ASL of this account from what is currently authorized is not an appropriate step to take for this account. If anything, the ASL should be shortened for this account.

Q 132 Does TURN believe that Net Zero by 2045 will result in shorter service lives for gas mains?

---

[144] CA-15, p. 13, lines 12-13.

A 132 Yes. In the response to discovery, TURN stated that:

> TURN believes that state goals for carbon neutrality are likely to result in service lives for gas mains being shorter by some as yet undetermined amount.[145]

Q 133 Is TURN's proposal for this account consistent with TURN's outlook for the service lives for gas mains?

A 133 No. In direct contradiction to TURN's belief about the outlook for gas mains, TURN has proposed to increase the average service life for this account by three years. Given this contradiction, we can conclude that TURN does not even believe its own proposal is correct. This is perhaps not surprising. Mr. Garrett stated in discovery that:

> Mr. Garrett has not analyzed California's state goals for carbon neutrality or the likely impact on service lives for gas mains.[146]

Given that TURN witness Garrett has not considered the impact of Net Zero by 2045 on this account and that TURN does not believe its proposal is correct, there is no way that TURN's proposal for this account is reasonable.

12) Account 378, Measuring and Regulating Station Equipment

Q 134 Please summarize the currently authorized and proposed estimates for this account.

A 134 The currently authorized and proposed estimates for each party are summarized in the table below.

TABLE 12-14
COMPARISON OF CURRENTLY AUTHORIZED, PG&E, CAL ADVOCATES AND TURN SERVICE LIFE ESTIMATES FOR ACCOUNT 378, MEASURING AND REGULATING STATION EQUIPMENT

Line No.	2020 GRC Authorized Estimate	PG&E Estimate	Cal Advocates Estimate	TURN Estimate
1	55-R2	55-R2	55-R2	59-R2

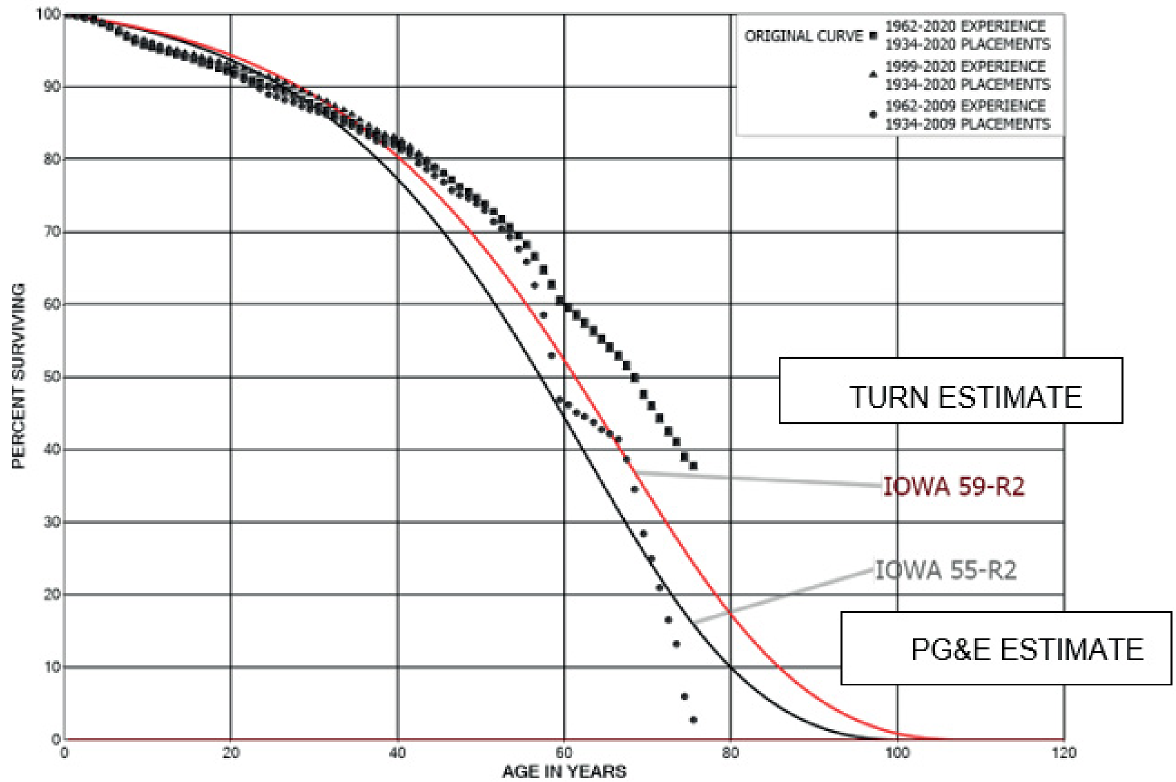
Please see Figure 12-20 below for a comparison of the estimates proposed for this account. The chart includes the overall band (shown as

145 See TURN's response to PG&E Data Request PGE_TURN006-Q07, dated 6/27/22 in Appendix A, at the end of this exhibit.

146 See TURN's response to PG&E Data Request PGE_TURN006-Q09, dated 6/27/22 in Appendix A, at the end of this exhibit.

black squares), the 1999-2020 experience band (shown as black triangles) and a band with data through 2009 (shown as black circles).

FIGURE 12-20
ACCOUNT 378 MEASURING AND REGULATING STATION EQUIPMENT
ORIGINAL LIFE TABLES FOR OVERALL AND 1999-2020 EXPERIENCE BANDS AND ESTIMATED SMOOTH SURVIVOR CURVES



Q 135 Does Mr. Garrett provide any support for his estimate other than the statistical results for the 1999-2020 experience band?

A 135 No.[147] Accordingly, the arguments I have made earlier in my testimony apply to this account as well.

Q 136 Please discuss Mr. Garrett's argument[148] that it is unnecessary to use statistically-aged data for this account.

A 136 The length of the "stub" OLT curve is not directly correlated to how many years of data are being analyzed. Even if the stub survivor curve extends to close to zero percent for the 1999-2020 band, it is still only based on 22

[147] TURN-18, pp. 43-45.

[148] TURN-18, p. 45, lines 8-13.

years of experience for any vintage. This is much less time than the 55-year ASL or the full life cycle of close to 100 years.

Q 137 Are there any other reasons why the service life should not be extended for this account?

A 137 Yes. Based on Gannett Fleming's experience in the industry, the upper end of the range of typical ASL estimates for this account is 55 years. It is uncommon for assets in this account to have a longer ASL. PG&E's estimate is already at the upper end of the industry range for this account. Given that the data incorporates atypical years with few retirements and the factors discussed in Section C.3.c, it is not reasonable to increase the service life beyond the upper end of the industry range for this account, particularly in the context of California's goal to be carbon neutral by 2045.

13) Account 380, Services

Q 138 Please summarize the currently authorized and proposed estimates for this account.

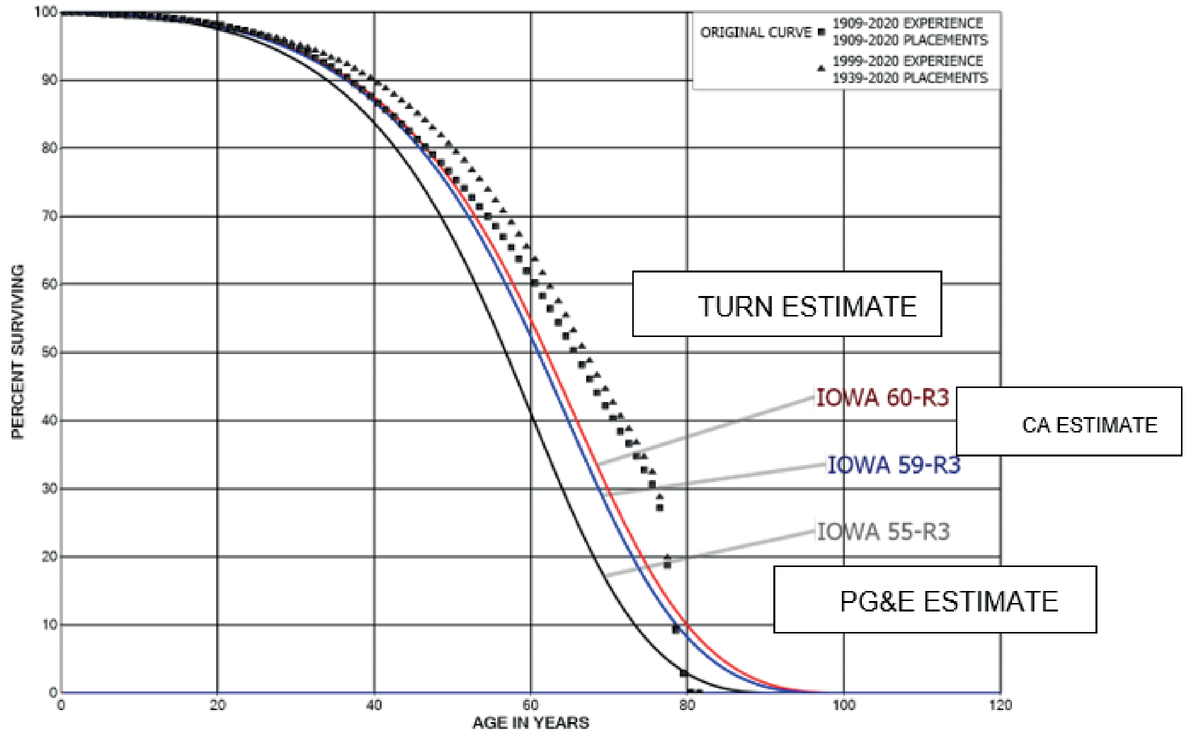
A 138 The currently authorized and proposed estimates for each party are summarized in the table below.

TABLE 12-15
COMPARISON OF CURRENTLY AUTHORIZED, PG&E, CAL ADVOCATES AND TURN SERVICE LIFE ESTIMATES FOR ACCOUNT 380, SERVICES

Line No.	2020 GRC Authorized Estimate	PG&E Estimate	Cal Advocates Estimate	TURN Estimate
1	57-R3	55-R3	59-R3	60-R3

Please see Figure 12-21 below for a comparison of the estimates for this account. The figure also shows the overall band (shown as black squares) and the 1999-2020 band (shown as black triangles) relied on by TURN.

FIGURE 12-21
ACCOUNT 380 SERVICES
ORIGINAL LIFE TABLES FOR OVERALL AND 1999-2020 EXPERIENCE BANDS AND ESTIMATED SMOOTH SURVIVOR CURVES



Q 139 Are the issues you have discussed previously in your testimony also applicable for this account?

A 139 Yes. Most important is that this is another example of how little consideration both Cal Advocates and TURN have given to factors other than the statistical analysis. Proposing to increase the service life for this account is unreasonable in the context of decarbonization goals and their likely impact on the gas system and gas customers. Additionally, as discussed above, it is more reasonable to expect that services will have a similar or shorter life than gas mains. The data also indicates a maximum life of around 80 years for this account, as both the overall and 1999-2020 experience bands decline to zero percent surviving by age 80. However, Cal Advocates' and TURN's estimates incorporate the expectation that about 10 percent will survive beyond this age. Finally, greenhouse gas emissions goals will impact this account, as service lines will be retired for any customers that fully electrify. Finally, factors discussed in Section C.3.c could affect the Company's gas accounts, which provides further reason for caution in increasing the life for the account.

Q 140 Please address the misrepresentation made by Cal Advocates related to the PG&E account narratives included in the depreciation workpapers for this case.

A 140 Cal Advocates claims that "PG&E states that services have an average useful life of 60 years or more…".[149] However, this is not what I stated on the page cited by Cal Advocates (PG&E-10, Ch. 12, WP p.12-2042). Instead, I explained that the best statistical fits of the data show average service lives of 60 years or more. However, as discussed in prior sections of this testimony, and especially when considering California's carbon neutral by 2045 goals, statistical best-fitting curves are not always the most appropriate curve to estimate for an account.

Q 141 Are there any other issues with the analysis related to Account 380 in Cal Advocates testimony?

A 141 Yes. Cal Advocates states, "Based on PG&E's proposal, plant account 376 (Mains) has an average service life of 44.37 years while plant account 380 (Services) has a service average life [sic] of 41.02 years, which are already well below the average of 60 years."[150] There are two issues with Cal Advocates' testimony here. First, PG&E's average service life estimate for Account 376 is 57 years (not 44.37) and PG&E's average service life estimate for Account 380 is 55 years (not 41.02). The numbers Cal Advocates refers to are the composite remaining lives of Account 376 and 380, not the average service lives.[151] Second, Cal Advocates' claim that the average service lives of both accounts is 60 years is incorrect. The currently authorized estimate for each account is the 57-R3, meaning that the current average service life for the account is 57 years.

Q 142 For Account 376, Mains, you discussed how TURN's proposal was contradicted by TURN's expectation that service lives will be shorter in the future. Is there a similar issue with this account?

---

149 CA-15, p. 15, lines 7-8.

150 CA-15, p. 15, lines 15-17.

151 Exhibit (PG&E-10) (Feb. 28, 2022), p. 12-7, Table 12-2, Column 7.

A 142 Yes. Similar to gas mains, TURN believes that lives for gas services will be shorter in the future due to Net Zero by 2045, but Mr. Garrett did not consider this when making his estimate.[152] Cal Advocates' were asked a similar question. However, they did not answer the question asked,[153] from which I think we can reasonably infer that Cal Advocates' has not considered the impact of Net Zero by 2045 in their estimates. Thus, given that neither party has even attempted to incorporate any impacts of Net Zero by 2045, their proposals should be rejected.

14) Account 381, Meters

Q 143 Please summarize the currently authorized and proposed estimates for this account.

A 143 The currently authorized and proposed estimates for each party are summarized in the table below.

TABLE 12-16
COMPARISON OF CURRENTLY AUTHORIZED, PG&E, CAL ADVOCATES AND TURN SERVICE LIFE ESTIMATES FOR ACCOUNT 381, METERS

2020 GRC Authorized Estimate	PG&E Estimate	Cal Advocates Estimate	TURN Estimate
28-S1	28-S1	28-S1	31-S1

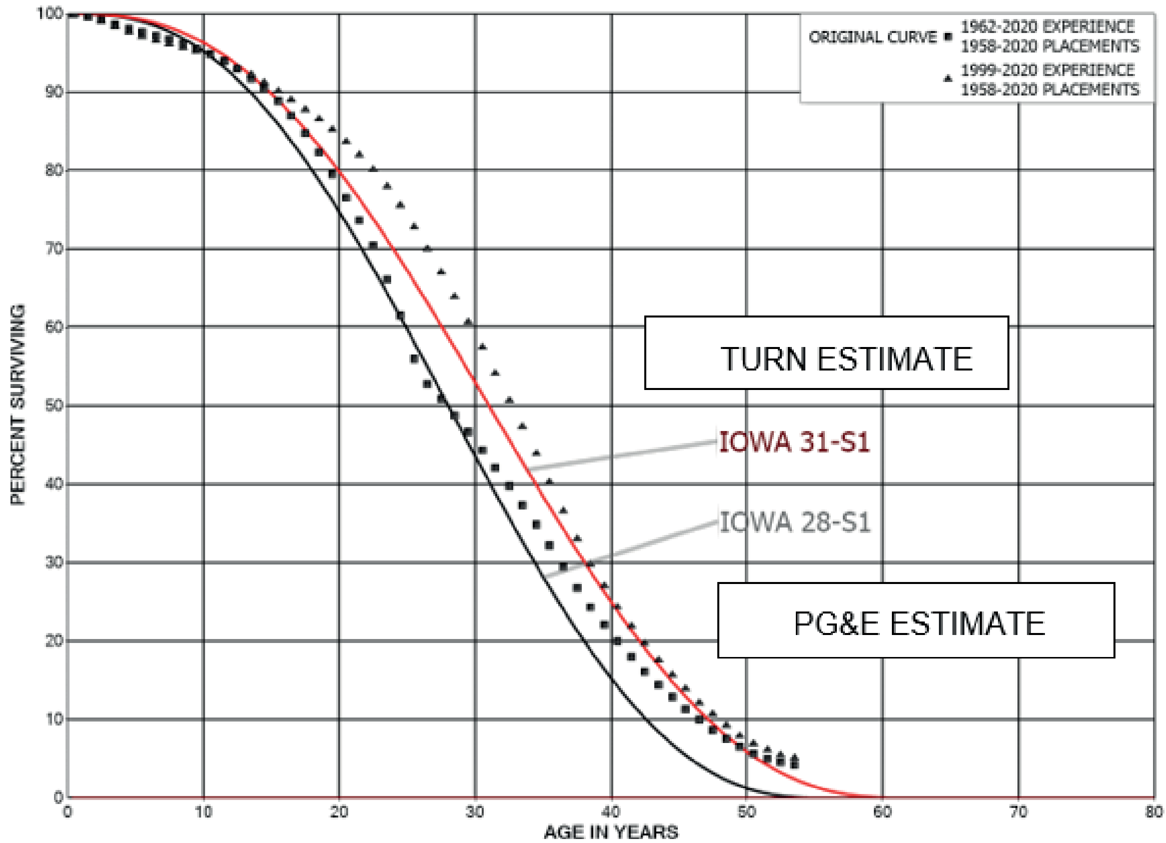
Please see Figure 12-22 below for a comparison of the estimates for this account. The figure also shows the overall band (shown as black squares) and the 1999-2020 band (shown as black triangles) relied on by TURN. As the figure shows, PG&E's estimate is a good fit of the overall band, whereas TURN's estimate does not fit either band particularly well.

---

152 See TURN's responses to PG&E Data Requests PGE_TURN006-Q08, dated 6/27/22, and PGE_TURN006-Q10, dated 6/27/22 in Appendix A, at the end of this exhibit.

153 See Cal Advocates' responses to PG&E Data Requests PGE_CalAdvocates005-Q01, dated 6/27/22, and PGE_CalAdvocates005-Q02, dated 6/27/22 in Appendix A, at the end of this exhibit.

FIGURE 12-22
ACCOUNT 381 METERS
ORIGINAL LIFE TABLES FOR OVERALL AND 1999-2020 EXPERIENCE BANDS AND ESTIMATED SMOOTH SURVIVOR CURVES



Q 144 Does TURN provide any support other than fitting curves to the more recent experience band?

A 144 No. TURN again relies only on the 1999-2020 band.[154] I have addressed this issue in more detail in Section C.3.e. As shown in Figure 12-22 above, Mr. Garrett's estimate does not fit either band particularly well, whereas PG&E's estimate is a good fit of the overall band.

15) Account 383, House Regulators

Q 145 Please summarize the currently authorized and proposed estimates for this account.

A 145 The currently authorized and proposed estimates for each party are summarized in the table below.

---

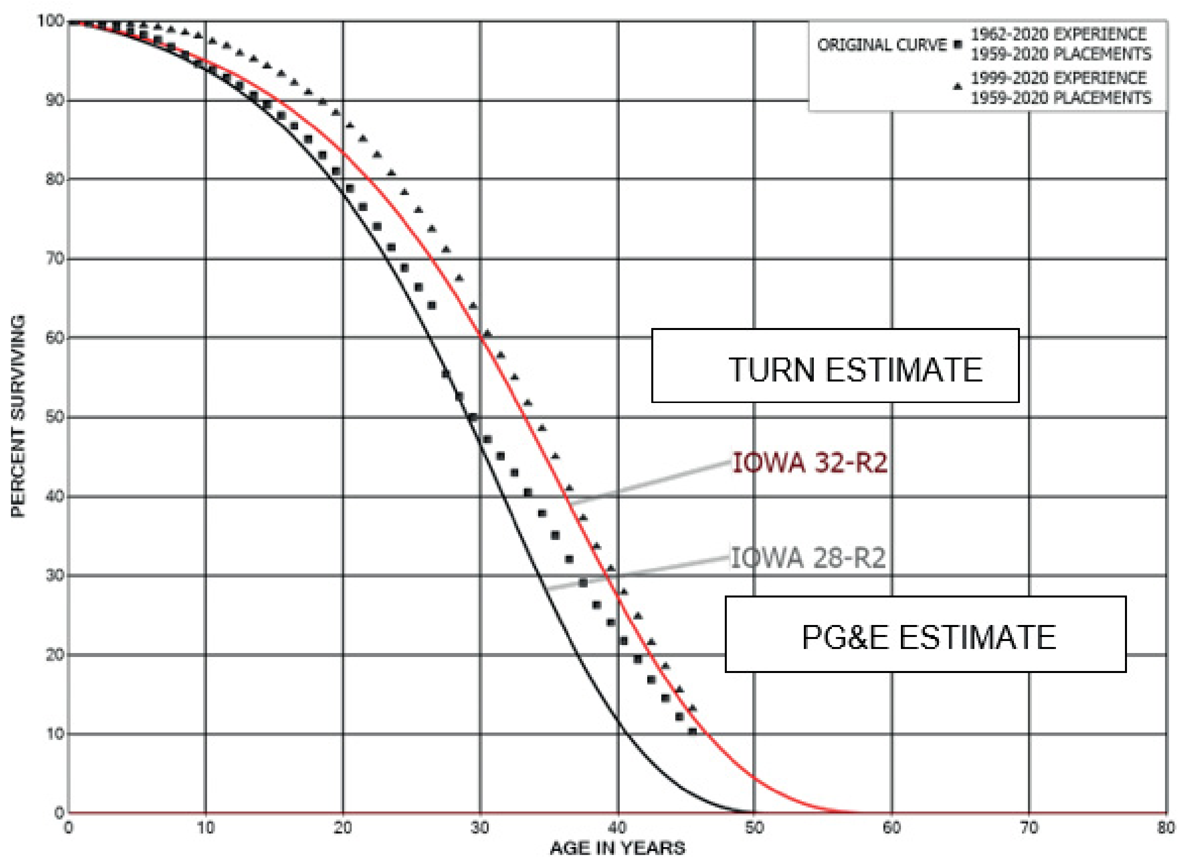
[154] TURN-18, pp. 48-49.

TABLE 12-17
COMPARISON OF CURRENTLY AUTHORIZED, PG&E, CAL ADVOCATES AND TURN SERVICE LIFE ESTIMATES FOR ACCOUNT 383, HOUSE REGULATORS

Line No.	2020 GRC Authorized Estimate	PG&E Estimate	Cal Advocates Estimate	TURN Estimate
1	28-R2	28-R2	28-R2	32-R2

Please see Figure 12-23 below for a comparison of the estimates for this account. The figure also shows the overall band (shown as black squares) and the 1999-2020 band (shown as black triangles) relied on by TURN. As the figure shows, PG&E's estimate is a good fit of the overall band, whereas TURN's estimate does not fit either band particularly well.

FIGURE 12-23
ACCOUNT 383 HOUSE REGULATORS
ORIGINAL LIFE TABLES FOR OVERALL AND 1999-2020 EXPERIENCE BANDS AND ESTIMATED SMOOTH SURVIVOR CURVES



Q 146 Does TURN provide any support other than fitting curves to the more recent experience band?

A 146 No. TURN again relies only on the 1999-2020 band.[155] I have addressed this issue in more detail in Section C.3.d. As shown in Figure 12-23 above, Mr. Garrett's estimate does not fit either band particularly well, whereas PG&E's estimate is a good fit of the overall band.

4. Net Salvage

a. General

Q 147 Please summarize the net salvage estimates for each party.

A 147 The net salvage estimates I have made for each account have been provided in Exhibit (PG&E-10), Chapter 12, Tables 12-1 through 12-3. Cal Advocates has recommended different net salvage estimates for four electric and three gas accounts.[156] Cal Advocates has not proposed changes to the estimates in my study for any other class of plant. TURN has proposed adjustments for five electric and six gas accounts, which includes the accounts Cal Advocates also proposes adjustments.[157] A comparison of my estimates to those of Cal Advocates and TURN are provided in Table 12-3 below. The table also shows the currently authorized estimates and those proposed by PG&E in the 2020 GRC.[158]

---

155 TURN-18, p. 49, line 14 to p. 51, line 4.

156 CA-15, p. 17, Table 15-5.

157 TURN-18, p. 61, Table 4.

158 See, D.18-12-009, Appendix D for the parameters authorized in the 2020 GRC and D.19-09-025, Exh. JS-03 for the authorized service lives from the 2019 Gas Transmission and Storage case.

TABLE 12-18
COMPARISON OF PG&E, CAL ADVOCATES, AND TURN NET SALVAGE ESTIMATES

Line No.	FERC Account	2020 GRC / 2019 GT&S PG&E Estimate	Currently Authorized Estimate	PG&E Estimate	Cal Advocates Estimate	TURN Estimate
1	Electric					
2	362, Station Equipment	(60)	(40)	(60)	(45)	(45)
3	364, Poles, Towers and Fixtures	(175)	(150)	(175)	(156)	(156)
4	367, UG Conductors and Devices	(80)	(65)	(80)	(69)	(69)
5	368.01, Line Transformers – OH	(40)	(30)	(40)	(34)	(34)
6	368.02, Line Transformers – UG	(25)	(25)	(35)	(35)	(28)
7	Gas					
8	352, Wells	(15)	(15)	(25)	(25)	(18)
9	353, Lines	(50)	(35)	(50)	(50)	(39)
10	367, Mains	(70)	(54)	(75)	(59)	(59)
11	376, Mains	(55)	(55)	(75)	(60)	(60)
12	378, Measuring and Regulating Sta Equip	(40)	(40)	(50)	(50)	(43)
13	380, Services	(100)	(81)	(100)	(86)	(86)

Q 148 Are PG&E’s estimates consistent with the methods set forth in SP U-4?

A 148 Yes. Specifically, the historical net salvage analysis is based on expressing historical net salvage as a percentage of historical retirements, as presented in SP U-4.[159]

Q 149 Are PG&E’s estimates consistent with the concept of gradualism discussed in Section C.1.e?

A 149 Yes. As I will show for each account at issue in Section C.4.e, many of PG&E’s proposals are conservative (i.e., less negative) when compared to the results of the statistical analysis set forth in SP U-4. In general, proposed changes in PG&E’s depreciation study are gradual, which is true whether the data indicated a more negative or a less negative net salvage estimate. As I will discuss, both Cal Advocates’ and TURN’s proposals are based almost entirely on applying gradualism to PG&E’s already gradual estimates.

Q 150 What are the bases for Cal Advocates’ net salvage proposals?

A 150 While Cal Advocates provides some commentary on the impact of cost increases on the net salvage analyses and certain accounting transactions, Cal Advocates proposals are primarily based on the concept of gradualism.

---

159 CPUC, *Determination of Straight-Line Remaining Life Depreciation Accruals* – Standard Practice U-4 (Jan. 3, 1961), p. 4. See paragraph 2 for an explanation of the net salvage analysis in which cost of removal and gross salvage are expressed as a percentage of retirements.

Witness Burns states that Cal Advocates recommends a "more measured approach to changes in net salvage rates."[160] This is explained as application of "the policy of gradualism."[161] Similar to previous cases, Cal Advocates relies on the concept of gradualism discussed In Section C.1.e to recommend less negative net salvage estimates than those recommended by PG&E.

Q 151 Does TURN also use the concept of gradualism to limit changes to PG&E's net salvage estimates?

A 151 Yes. TURN has cited gradualism as the reason for limiting changes in net salvage and this appears to be the only justification provided for TURN's proposals.[162] Due to TURN's interpretation of gradualism, Mr. Garrett's recommendations result in changes that are no more than six percentage points from the currently approved estimate —in instances where net salvage is more negative than the current estimates. However, TURN does not apply this concept consistently, as Mr. Garrett uses a net salvage estimate for Account 365, Overhead Conductors and Devices, that is 15 percentage points less negative than the currently authorized estimate. It is not consistent with the concept of gradualism to only be gradual in one direction.

Q 152 Do you believe Cal Advocates' and TURN's proposals are consistent with the concept of gradualism?

A 152 No. As discussed previously, for both gas and electric distribution plant, both parties propose to decrease depreciation from currently authorized levels. In practice, their use of what they call gradualism does not limit increases in depreciation but instead artificially reduces depreciation. Given the factors and reasons discussed previously as to why we should expect increases in depreciation for both electric and gas distribution plant, their use of gradualism provides too little of recovery of net salvage costs to be equitable.

---

160 CA-15, p. 17, lines 3-4.

161 CA-15, p. 17, lines 4-5.

162 TURN-18, p. 59.

Q 153 What support does Mr. Garrett provide for his estimates?

A 153 Mr. Garrett's support, aside from his reference to gradualism, is an arbitrary limitation of "25% of the amount of increase proposed by PG&E."[163] TURN's overall approach is not consistent with Commission precedent, as discussed in more detail in the next section. I will also address both Cal Advocates' and TURN's specific proposals by account in Section C.4.e.

b. Unlike Cal Advocates and TURN, PG&E is Consistent in Its Application of Gradualism

Q 154 Are PG&E's recommended net salvage estimates consistent with the concept of gradualism?

A 154 Yes. I have generally limited changes in the net salvage percentage to be no more than 25 percentage points. This is consistent with Cal Advocates' definition of gradualism in PG&E's 2014 GRC.[164] For the accounts listed above for which I have recommended a more negative net salvage estimate than the currently authorized estimate, the historical net salvage data (and particularly the more recent data) are supportive of a more negative estimate than I have recommended. I have also proposed less negative net salvage estimates when supported by the data, such as for Account 365, Overhead Conductors and Devices.

For the accounts at issue, neither Cal Advocates nor TURN has proposed a net salvage estimate that is more than 6 percentage points more negative than the currently authorized estimate. However, both have used the same estimate for Account 365 as I have recommended, which is 15 percentage points less negative than the current estimate. I do not believe this is a balanced or fair approach to gradualism. If we are to use gradualism, it should be symmetric and consistently applied in both directions. TURN's lack of gradualism for service lives and the fact that both parties have proposed decreases in depreciation for gas and electric distribution accounts demonstrates that neither party are attempting to apply gradualism in a consistent manner – whether from the standpoints of being gradual with changes to estimates or in assessing increases in depreciation.

---

163 TURN-18, p. 60, line 14.

164 See, A.12-11-009, DRA-19, p. 1, lines 21-23.

Instead, both have – at least in effect if not intent – used gradualism to artificially reduce depreciation.

Q 155 For the accounts for which Cal Advocates' or TURN propose to use gradualism, has gradualism been used to limit changes in net salvage for some of these accounts in previous GRCs?

A 155 Yes. For several of the electric accounts for which both Cal Advocates or TURN propose to limit the change in net salvage, PG&E's recommendations were already limited in the 2020 GRC (and in previous GRCs). As Table 12-3 shows, for many of the accounts at issue PG&E's proposed estimates in the 2020 GRC were more negative than those that were eventually authorized through a settlement agreement. The same occurred in the 2017 GRC[165] and, as discussed in Section C.1.e, changes to net salvage estimates were limited based on gradualism in PG&E's 2014 GRC. Due to the economic conditions at the time of PG&E's 2011 GRC, PG&E had also voluntarily limited changes to net salvage in that case.[166] Finally, I again stress that PG&E has not proposed changes to the net salvage estimates for any of these accounts that result in increases in negative net salvage of more than negative 25 percent, which was the degree of change Cal Advocates used to define gradualism in PG&E's 2014 GRC.[167] In summary, for the accounts for which Cal Advocates and TURN cite to gradualism to support their proposals, gradualism has already been used to limit increases in negative net salvage account in PG&E's previous three GRCs and PG&E's proposals in the instant case are already gradual. There is no need for any additional use of gradualism for these accounts.

Q 156 Given this context, do you believe that Cal Advocates' and TURN's proposals to further limit the changes in net salvage for these accounts are appropriate?

---

165 See A.15-09-001, Joint Motion for Adoption of Settlement Agreement (Aug. 3, 2016), Appendix C, Settlement Agreement (as ratified by D.17-05-013).

166 See A.09-12-020, Exhibit (PG&E-2), p. 10-6.

167 See A.12-11-009, DRA-19, p. 1, lines 21-23, in which DRA stated:

> DRA recommends that increases to net salvage be capped at -25 percent for this GRC cycle in order to mitigate the overall impact on rates.

Cal Advocates was known as DRA in the 2014 GRC.

A 156 No. The increases in negative net salvage for these accounts have already been limited in recent GRC cycles, and PG&E's proposed increases are consistent with Cal Advocates' previous testimony as to what constitutes a gradual and reasonable increase in net salvage. Further, PG&E's data and analysis for most accounts not only supports that PG&E's estimates are reasonable, but that they are conservative when compared to the historical data. Finally, given that both Cal Advocates and TURN propose decreases in depreciation for gas and electric distribution plant, PG&E is concerned that the concept of gradualism is not being used to mitigate what the Commission referred to in PG&E's 2014 GRC as "an unacceptably abrupt impact on current ratepayers,"[168] but rather is merely used as a means to lower depreciation rates from whatever PG&E proposes. Given the factors influencing the electric and gas industry in California discussed in Section related to Net Zero by 2045, using gradualism to artificially lower depreciation rates—which is the result of Cal Advocates' and TURN's proposals for electric and gas distribution—will only serve to increase the risk of stranded costs and inequitable deferrals of costs to future generations of customers.

Q 157 Has PG&E used the concept of gradualism consistently?

A 157 Yes, particularly when compared to Cal Advocates and TURN's proposals. As noted previously, none of my proposed changes in net salvage exceed 25 percentage points, and I have used the same approach independent of whether the result would increase or decrease negative net salvage and depreciation expense. Further, as discussed in Section C.1.e, I have incorporated the concept of gradualism for both service lives and net salvage.

Q 158 Do you have any reason to believe that the Commission intended for gradualism to be applied inconsistently?

A 158 No. In fact, the opposite is true. As I have discussed in Section C.1.e, in PG&E's 2014 GRC the Commission discussed gradualism for both net salvage and service lives, which I believe provides evidence for consistency. I again note that the Commission stated that:

---

[168] See D.14-08-032, p. 726, Conclusion of Law (COL) 17.

> [I]t is advisable to be cautious in making large changes in estimates of service lives and net salvage for property that will be in service for many decades, as future experience may show the current estimates to be incorrect.[169]

This discussion also implies consistency in making gradual changes.

Finally, properly balancing the interests of current and future customers means that to the extent gradualism should be applied, it should be done consistently. I do not believe that the Commission's intent was to simply provide a means to arbitrarily reduce PG&E's depreciation expense by selectively using gradualism, which is what TURN and Cal Advocates have proposed to do.

c. Response to Cal Advocates' Conceptual Argument

Q 159 What is the primary conceptual argument regarding net salvage set forth by Cal Advocates?

A 159 Cal Advocates/Burns presents an argument that net salvage percentages will be higher subsequent to changes in the level of work needed for removal activities.[170] Mr. Burns first presents the formula for the net salvage percentage used in the net salvage analysis set forth in SP U-4:

$$Net\ salvage\ percentage_t = \frac{(Recorded)net\ salvage\ activity_t}{(Recorded)retirements_t}$$

He then argues that changes in work requirements will immediately affect the numerator of the fraction set forth above. However, he argues, the denominator "will remain unaffected for many years because retiring plant is denominated in original cost."[171] He adds that:

> [T]he recorded retirements predominantly reflect plant that has served its useful life, with an original cost recorded at the start of that life some decades previously.[172]

Q 160 Are there any problems with Cal Advocates' argument?

---

169 D.14-08-032, p. 598.

170 CA-15, pp. 18-19.

171 CA-15, p. 18, line 25 to p. 19, line 2.

172 CA-15, p. 19, lines 2-3.

A 160 Yes. There are at least two primary problems with Cal Advocates' argument. The first is that Mr. Burns fails to observe the importance of the fact that the net salvage ratio is applied to plant in service. PG&E's current asset base is not all new. Instead, many assets were installed in the past. Thus, while it may take time for the denominator of the net salvage ratio to fully reflect any changes in work requirements, the same is true for the original cost of the Company's asset in service (to which the ratio will be applied).

The second problem with Mr. Burns's argument is that historical retirements are not all older assets. Instead, assets are also replaced at earlier ages for reasons such as relocations or damage. As a result, the denominator of the net salvage ratio will reflect changes in work requirements sooner than Mr. Burns expects. This can be seen by the fact that the average age of historical retirements is typically less than the overall average service life of an account. As a result, the time for the impact of work requirements on the denominator of the net salvage ratio is less than assumed by Mr. Burns's argument.

Q 161 Please provide an example to illustrate these concepts.

A 161 Consider Account 367, Underground Conductors and Devices. This is one of the accounts for which Cal Advocates proposes a less negative net salvage estimate than PG&E. The historical net salvage analysis is provided on page WP 12-582 and WP 12-583 of the workpapers supporting Exhibit (PG&E 10), Chapter 12. The overall period studied was 2001 through 2020. Aged data (i.e., data for which the age of retirements is known) was available for 1999 through 2020. For this period, the retirements in the net salvage analysis averaged 27.6 years of age. This is considerably shorter than the ASL for the account of 52 years. Further, the average age of assets in service as of December 31, 2020 was 16.2 years. As a result, the overall difference between the age of retirements (the denominator in the net salvage ratio) and the age of assets in service (the balance to which the net salvage ratio is applied) is not significantly large (and is actually more than half the difference between the average age of historical retirements and the average age of future retirements).

The concept that the age of retirements in the statistical analysis is typically less than the ASL is one reason why it is generally understood that the method of analyzing net salvage set forth in SP U-4 tends to result in conservative (i.e., less negative) estimates of future net salvage.

Q 162 Has the Commission previously recognized that SP U-4 results in conservative estimates of future net salvage?

A 162 Yes. In PG&E's 2007 GRC, the Commission concluded that:

> [T]he Settling Parties have demonstrated with their pole example, *supra*, that the accrual method set forth in SP U-4 (and as implemented by PG&E) results in a conservative projection of future inflation that probably understates future removal costs in nominal dollars.[173]

Q 163 Do you have any other comments on Cal Advocates' conceptual discussion?

A 163 Yes. As noted previously, and in Exhibit (PG&E-10), Chapters 11 and 12, the recommended net salvage estimates in the depreciation study are, generally speaking, conservative. This is largely the result of incorporating the concept of gradualism. A strict adherence to the methodology set forth in SP U-4 would result in more negative net salvage estimates than I have proposed and, as discussed above, the SP U-4 method itself has been found to result in conservative projections of removal costs. Accordingly, even if there were any validity to Mr. Burns's discussion, any potential concerns are already addressed by the conservative nature of PG&E's estimates. There is no basis to reduce net salvage even further as proposed by Cal Advocates.

d. Cal Advocates' Discussions of PG&E's Data

Q 164 Does Cal Advocates provide criticisms of PG&E's data?

A 164 Yes. While it is unclear how these criticisms informed Mr. Burns's proposals, he does discuss certain transactions in the data.[174] However, Mr. Burns's testimony about these transactions is incorrect and does not reflect what has actually been recorded or reflected in the depreciation study.

---

[173] See D.07-03-044, p. 227.

[174] CA-15, p. 19, line 20 to p. 20, line 26.

Q 165 Please explain.

A 165 For certain accounts, most notably gas transmission accounts, PG&E was required to record write-offs for costs the Commission did not allow in rate base. These costs were initially recorded at a high level (i.e., not associated with specific assets or transactions) in order to reflect these amounts in total for PG&E's financial records. Later, PG&E determined the more precise accounting and recorded these costs to greater detail in its books and records. As a result, there are four transactions related to each of these, which are as follows:

1. The original cost of removal transaction.
2. The disallowance of this cost of removal amount, recorded at a high level.
3. The reversal of the high-level amount in #2.
4. The disallowance of the cost of removal at a more detailed level.

Transactions #1 and #3 are positive cost of removal amounts and #2 and #4 are negative amounts. Transactions #2 and #3 offset each other and have net effect of zero, meaning that the Company's current rate base reflects the original transaction, and the write-off amount, producing a net cost of zero (or, in the case of a partial write-off, the partially written-off amount). Thus, the net effect is that the disallowances are not included in rate base, which is reflected on PG&E's books for ratemaking purposes.

Q 166 Should the same approach be used for the net salvage analysis?

A 166 No. The purpose of the net salvage analysis is to analyze what it actually costs to retire assets compared to the retirement amounts in order to estimate future net salvage. Because we should not expect future cost of removal to incorporate disallowances, the recorded disallowances should be treated as abnormal activity and excluded from the net salvage analysis. I note that reviewing data and excluding abnormal activity is a typical and accepted practice for depreciation studies, as the intent is to develop a database for the analysis that is most reflective of future experience.

For this reason, transaction #2 has not been included in the net salvage analysis (nor was it in the previous depreciation study). The net effect is that the total cost of removal reflects the actual amount it cost to retire the related assets. Cal Advocates' appears to misunderstand how these transactions were treated, as Mr. Burns incorrectly claims that “PG&E not only did not reduce the costs in 2016 cost of removal recorded data, but also added it back again as ‘reversal entry’ in 2020 which duplicated and increased recorded cost of removal.”[175] It is incorrect that the cost of removal was duplicated – because transactions #3 and #4 offset one another, the net effect is zero. By excluding transaction #2, the net effect is that the cost of removal reflected in the data is the actual cost incurred (because #2 is excluded and #3 and #4 sum to zero, the total is equal to transaction #1). This is the appropriate level of net salvage to reflect in the net salvage analysis (although it is different from what is reflected in rate base).

Q 167 Please provide an example to demonstrate why the disallowances should not be included in the net salvage analysis.

A 167 Consider an example where we have two assets that have been retired, both with an original cost of $1,000, a cost of removal of $500 and no gross salvage. For the net salvage analysis, the total net salvage would be negative $1,000 (since the net salvage for each is negative $500) and the total retirement would be $2000. The negative net salvage percentage would then be ($1,000)/$2,000 = (50%). Absent major changes to cost of removal, this negative 50 percent would be reflective of what we can expect for future net salvage for the assets still in service.

If the costs of one of these assets were disallowed, then this should not affect our expectations for future net salvage – future cost of removal is not likely to be disallowed for the vast majority of assets – and so our expectation of negative 50 percent net salvage would be unchanged. If, however, we include the disallowance in the net salvage analysis then the resultant net salvage percentage would be ($500)/$2,000=(25%). Including the disallowance in the net salvage analysis would therefore produce an incorrect and misleading result, in this case resulting in an estimate that is half what it should be.

For this reason, the disallowance, while reflected in rate base, should not be included in the net salvage analysis.

[175] CA-15, p. 20, lines 14-16.

Q 168 Even if the disallowance were included for the account discussed by Cal Advocates, would the data still support your estimate?

A 168 Yes. Including the disallowance would not change the historical net salvage enough that the data would no longer support my estimate, which, as I discuss more for as Account 367, is conservative when compared to the data. Thus, while Cal Advocates' understanding of the concept and the details of this transaction are mistaken, even if one followed Mr. Burns's approach the data would still support my estimate.

e. Account-By-Account Discussion

1) Account 362, Station Equipment

Q 169 Please summarize the currently authorized and proposed estimates for this account.

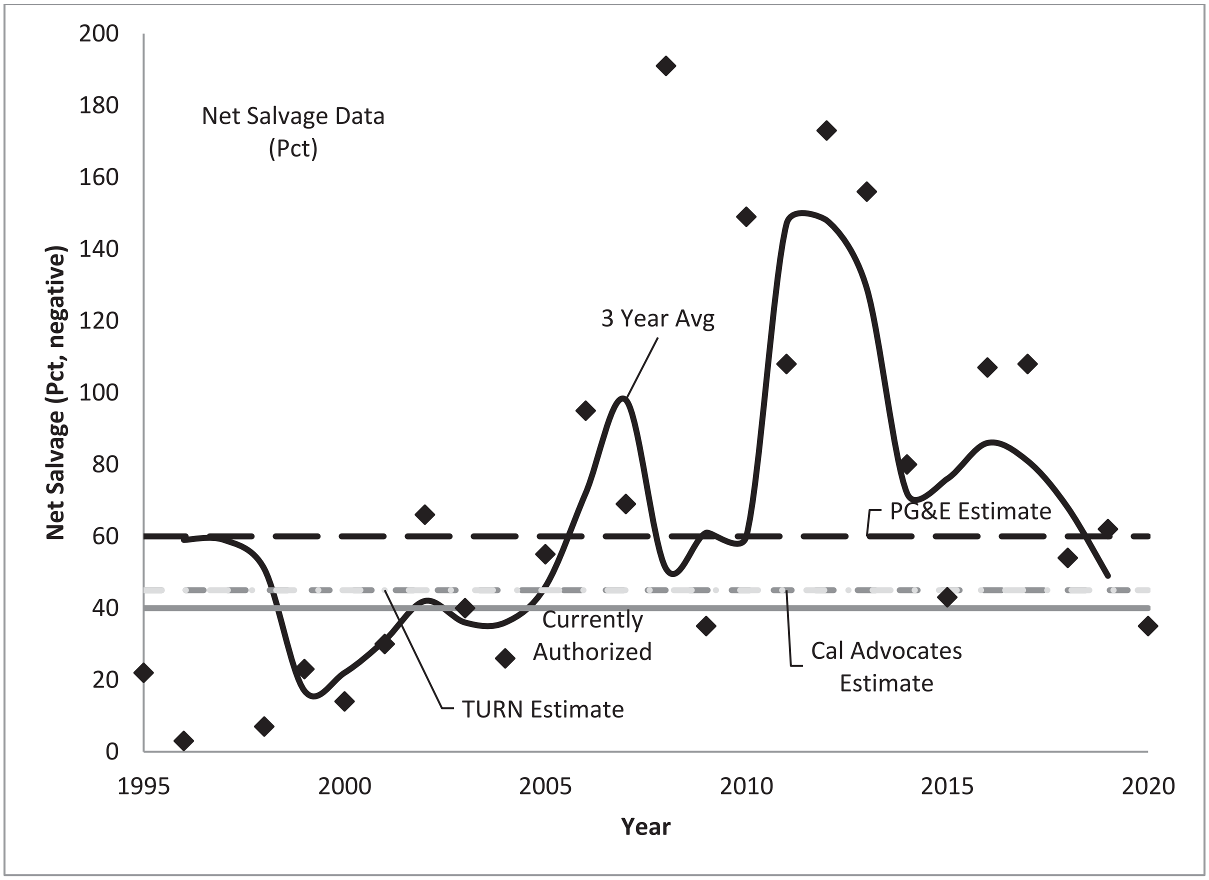
A 169 The currently authorized and proposed estimates for each party are summarized in the table below.

TABLE 12-19
COMPARISON OF CURRENTLY AUTHORIZED, PG&E, CAL ADVOCATES AND TURN NET SALVAGE ESTIMATES FOR ACCOUNT 362, STATION EQUIPMENT

Line No.	2020 GRC Authorized Estimate	PG&E Estimate	Cal Advocates Estimate	TURN Estimate
1	(40)	(60)	(45)	(45)

Figure 12-24 provides a comparison of the historical data to each estimate. The net salvage percentages for each year are shown as black diamonds and the three-year moving average net salvage percentages are shown as the solid black line. The estimates of each party are shown as dashed lines or a solid gray line. The chart illustrates that net salvage has generally trended more negative but has fluctuated in recent years. The chart shows that PG&E's estimate is conservative, compared to data since the mid-2000s. In contrast, the currently authorized, Cal Advocates' and TURN's estimates are all well below the overall average and are generally below each of the 3-year averages of recorded data since the mid-2000s.

FIGURE 12-24
ACCOUNT 362 STATION EQUIPMENT
COMPARISON OF NET SALVAGE ESTIMATES TO HISTORICAL NET SALVAGE DATA



Q 170 Has Cal Advocates provided any support specific to this account for Cal Advocates' estimate?

A 170 No. Mr. Burns's testimony provides general discussions on net salvage, which I have addressed previously. He does not provide any information specific to this account to support his estimate. His proposal appears to be based on the concept of gradualism.[176]

Q 171 Does TURN provide and support specific to this account for Mr. Garrett's estimate?

A 171 No. TURN does not provide any discussion specific to this account other than to cite to gradualism as a basis for Mr. Garrett's proposals.[177] However, as is illustrated in the chart above, TURN's estimate, like Cal

---

[176] CA-15, p. 22, lines 6-12.

[177] TURN-18, p. 60, lines 10-15.

Advocates', is too gradual a change. Indeed, PG&E's proposal is already gradual when compared to the historical data.

Q 172 Please explain why your estimate is most appropriate for this account.

A 172 As shown in Figure 12-24 and in the Chapter 12, Exhibit (PG&E-10) workpapers,[178] the data is supportive of an estimate at least as negative as negative 60 percent. This estimate is also the same estimate as used for transmission substation equipment. PG&E has proposed the same estimate in prior GRCs. Neither Cal Advocates nor TURN have provided sufficient justification to limit the change to this account any further, particularly because PG&E's proposal is already a relatively gradual change.

2) Account 364, Poles, Towers, and Fixtures

Q 173 Please summarize the currently authorized and proposed estimates for this account.

A 173 The currently authorized and proposed estimates for each party are summarized in the table below.

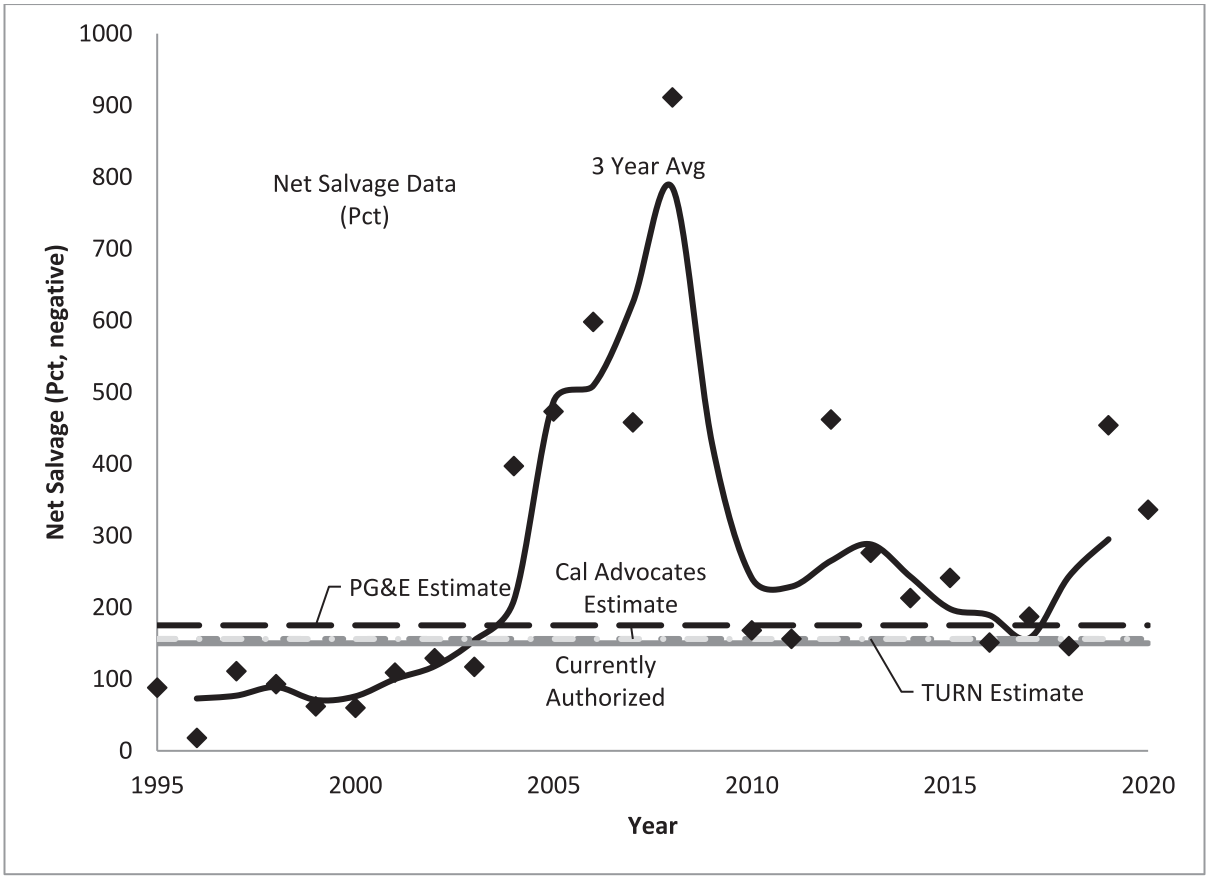
TABLE 12-20
COMPARISON OF CURRENTLY AUTHORIZED, PG&E, CAL ADVOCATES AND TURN NET SALVAGE ESTIMATES FOR ACCOUNT 364, POLES, TOWERS AND FIXTURES

Line No.	2020 GRC Authorized Estimate	PG&E Estimate	Cal Advocates Estimate	TURN Estimate
1	(150)	(175)	(156)	(156)

Figure 12-25 provides a comparison of the historical data to each estimate. The chart illustrates that net salvage has trended more negative and supports an estimate at least as negative as that proposed by PG&E.

[178] See Exhibit (PG&E-10) (Feb. 28, 2022), WP 12-520 and WP 12-521.

FIGURE 12-25
ACCOUNT 364 POLES, TOWERS, AND FIXTURES
COMPARISON OF NET SALVAGE ESTIMATES TO HISTORICAL NET SALVAGE DATA



The chart helps to illustrate the problems with Cal Advocates and TURN's approach. The data supports an estimate that is more negative than any party's proposal, including PG&E's. As can be seen above, the limited movement proposed by Cal Advocates and TURN is too small of a move towards the indications in the data. Further, PG&E has proposed the same negative 175 percent estimate in each of the last three GRCs (including this one), with changes limited in the eventual authorized estimates due to gradualism. Given the scope of replacement or undergrounding work planned for this account, it is more appropriate and reasonable to make a more meaningful movement to the appropriate level of net salvage.

Q 174 Have Cal Advocates or TURN provided any information specific to this account in support their estimates?

A 174 No. Both TURN's and Cal Advocates' proposals are based on the concept of gradualism.[179] However, as shown in the chart above, PG&E's estimate is already gradual and TURN's and Cal Advocates' proposals are too gradual when compared to the historical data.

Q 175 Please explain why your estimate is most appropriate for this account.

A 175 As shown in Figure 12-25, and in the Chapter 12, Exhibit (PG&E-10) workpapers,[180] the data are supportive of an estimate of at least negative 175 percent. Neither Cal Advocates nor TURN has provided sufficient justification to limit the change to this account, particularly because PG&E's proposal is already a relatively gradual change and increases in negative net salvage have already been limited due to gradualism in previous GRCs.

3) Account 367, Underground Conductors and Devices

Q 176 Please summarize the currently authorized and proposed estimates for this account.

A 176 The currently authorized and proposed estimates for each party are summarized in the table below.

TABLE 12-21
COMPARISON OF CURRENTLY AUTHORIZED, PG&E, CAL ADVOCATES AND TURN NET SALVAGE ESTIMATES FOR ACCOUNT 367, UNDERGROUND CONDUCTORS AND DEVICES

Line No.	2020 GRC Authorized Estimate	PG&E Estimate	Cal Advocates Estimate	TURN Estimate
1	(65)	(80)	(69)	(69)

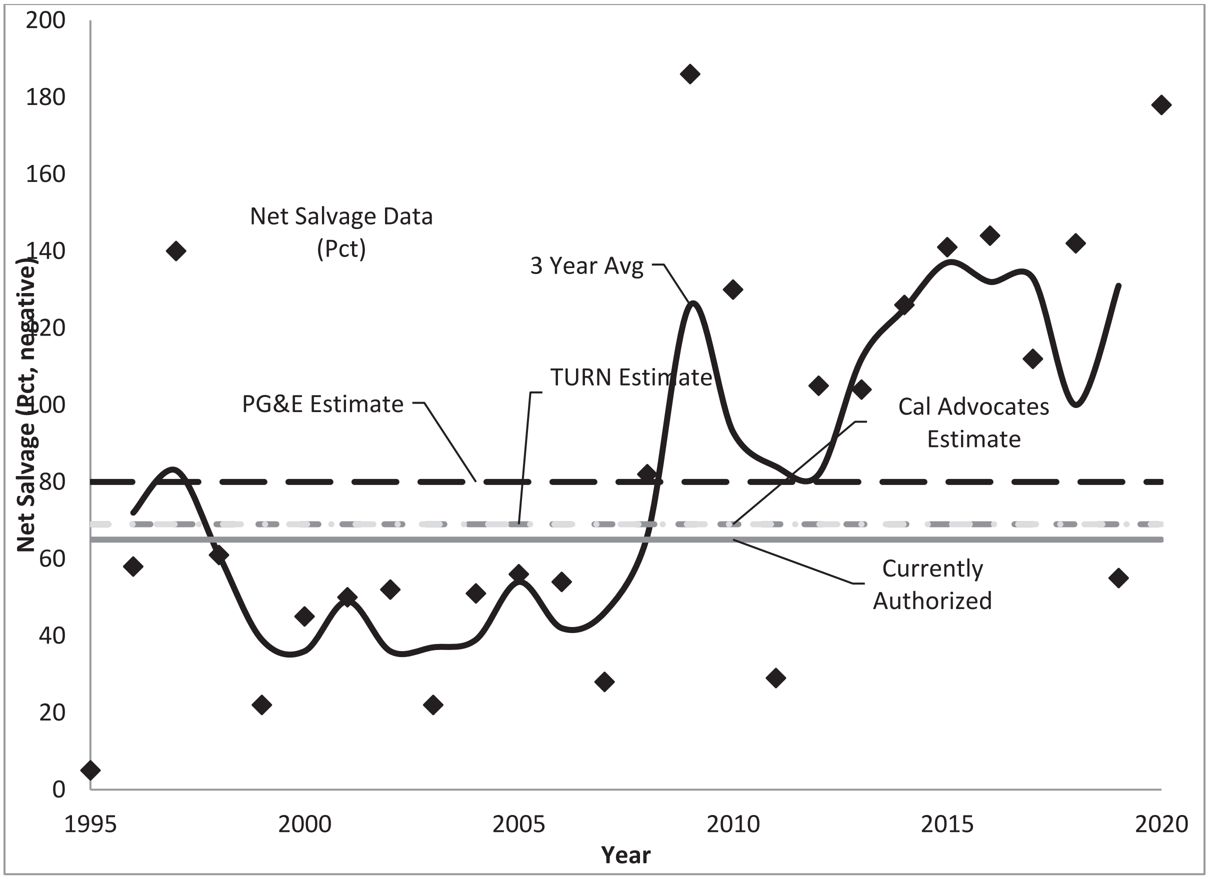
Figure 12-26 provides a comparison of the historical data to each estimate. The chart illustrates that net salvage has trended more negative and supports an estimate at least as negative as that proposed by PG&E.

---

179 TURN-18, p. 60, lines 10-11; CA-15, p. 22, lines 9-10.

180 See Exhibit (PG&E-10) (Feb. 28, 2022), WP 12-531.

FIGURE 12-26
ACCOUNT 367 UNDERGROUND CONDUCTORS AND DEVICES
COMPARISON OF NET SALVAGE ESTIMATES TO HISTORICAL NET SALVAGE DATA



Q 177 Have Cal Advocates or TURN provided any support for their estimates specific to this account?

A 177 No. Cal Advocates' and TURN's proposals are based on the concept of gradualism. However, because PG&E's proposal is only a 15-percentage point change in net salvage, there is no need for additional gradualism.

Q 178 Please explain why your estimate is most appropriate for this account.

A 178 As discussed above, the overall average net salvage and the more recent data are both supportive of an even more negative estimate than I have recommended. My recommendation is a change of 15 percentage points, which, as discussed in Section C.4.b, is smaller than the amount Cal Advocates has previously supported as gradual. Cal Advocates has not provided sufficient justification to limit the change to this account, particularly because PG&E's proposal is already a gradual change.

4) Account 368.01, Line Transformers – Overhead

Q 179 Please summarize the currently authorized and proposed estimates for this account.

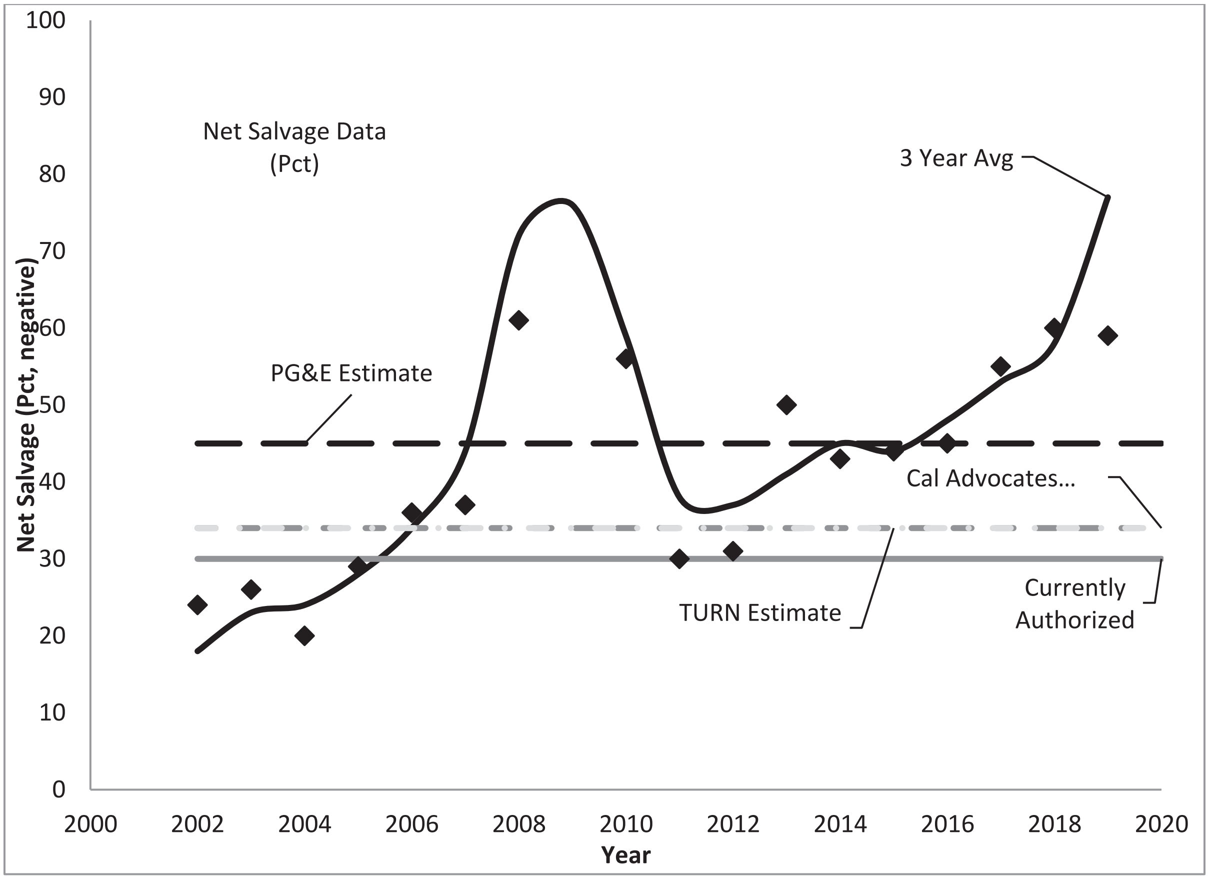
A 179 The currently authorized and proposed estimates for each party are summarized in the table below.

TABLE 12-22
COMPARISON OF CURRENTLY AUTHORIZED, PG&E, CAL ADVOCATES AND TURN NET SALVAGE ESTIMATES FOR ACCOUNT 368.01, LINE TRANSFORMERS - OVERHEAD

Line No.	2020 GRC Authorized Estimate	PG&E Estimate	Cal Advocates Estimate	TURN Estimate
1	(30)	(45)	(34)	(34)

Figure 12-27 provides a comparison of the historical data to each estimate.

FIGURE 12-27
ACCOUNT 368.01 TRANSFORMERS – OVERHEAD
COMPARISON OF NET SALVAGE ESTIMATES TO HISTORICAL NET SALVAGE DATA



Q 180 Have TURN or Cal Advocates provided any support for their estimates specific to this account?

A 180 No. Their proposals are based on the concept of gradualism. However, because PG&E's proposal is only a 15-percentage point change in net salvage, there is no need for additional gradualism.

Q 181 Please explain why your estimate is most appropriate for this account.

A 181 As discussed above, the historical data are supportive of a negative 45 percent net salvage estimate. My recommendation is a change of 15 percentage points, which is already a gradual change. TURN and Cal Advocates have not provided sufficient justification to limit the change to this account, particularly because PG&E's proposal is already a gradual change.

5) Account 368.02, Line Transformers – Underground

Q 182 Please summarize the currently authorized and proposed estimates for this account.

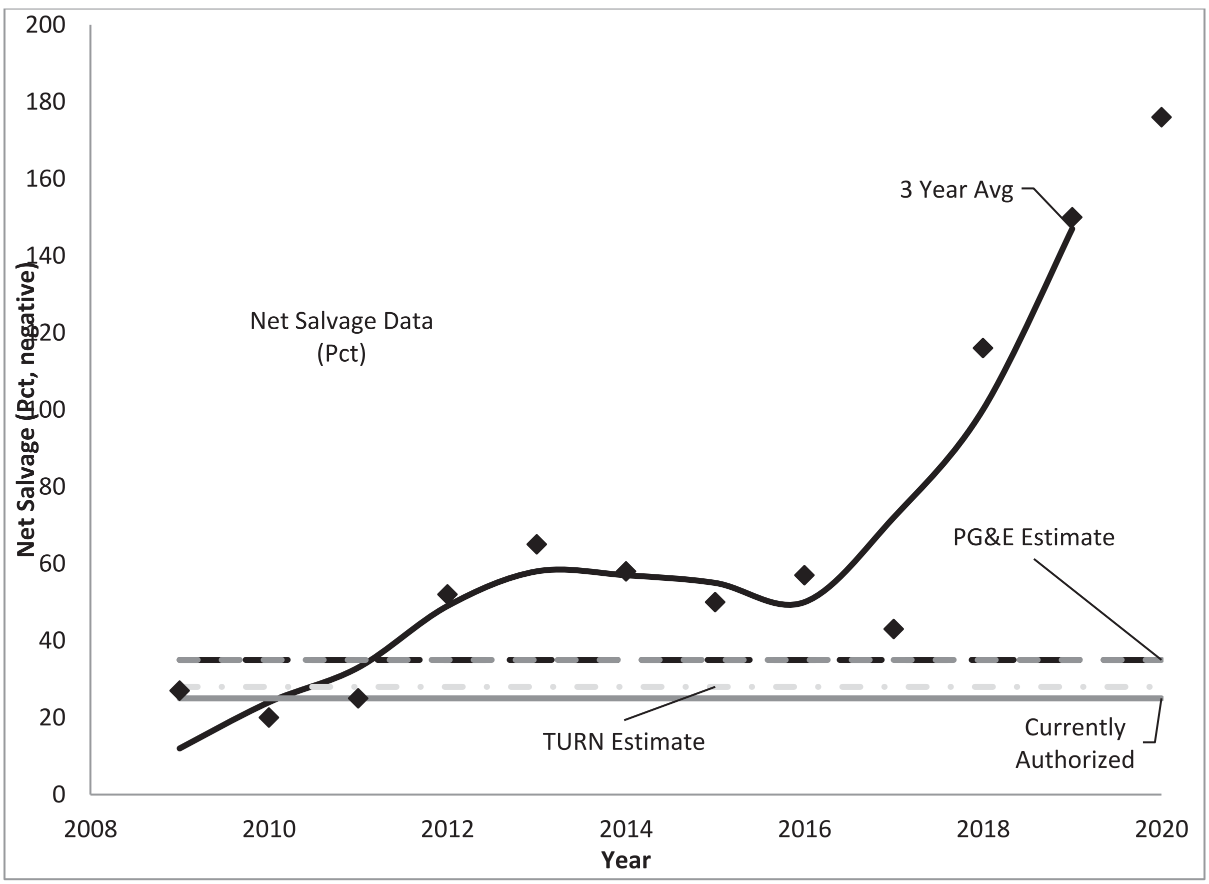
A 182 The currently authorized and proposed estimates for each party are summarized in the table below.

TABLE 12-23
COMPARISON OF CURRENTLY AUTHORIZED, PG&E, CAL ADVOCATES AND TURN NET SALVAGE ESTIMATES FOR ACCOUNT 368.02, LINE TRANSFORMERS - UNDERGROUND

Line No.	2020 GRC Authorized Estimate	PG&E Estimate	Cal Advocates Estimate	TURN Estimate
1	(25)	(35)	(35)	(28)

Figure 12-28 provides a comparison of the historical data to each estimate.

FIGURE 12-28
ACCOUNT 368.02 LINE TRANSFORMERS – UNDERGROUND
COMPARISON OF NET SALVAGE ESTIMATES TO HISTORICAL NET SALVAGE DATA



Q 183 Has TURN provided any support for Mr. Garrett’s estimate specific to this account?

A 183 No. TURN's proposal is based on the concept of gradualism. However, because PG&E's proposal is only a 10-percentage point change in net salvage, there is no need for additional gradualism. As can be seen in the graph above, PG&E's proposal is already quite gradual when compared to the data.

Q 184 Please explain why your estimate is most appropriate for this account.

A 184 As discussed above, the historical data are supportive of a negative 35 percent net salvage estimate. My recommendation is a change of 10 percentage points, which is already a gradual change. TURN has not provided sufficient justification to limit the change to this account, particularly because PG&E's proposal is already a gradual change.

6) Account 352, Wells

Q 185 Please summarize the currently authorized and proposed estimates for this account.

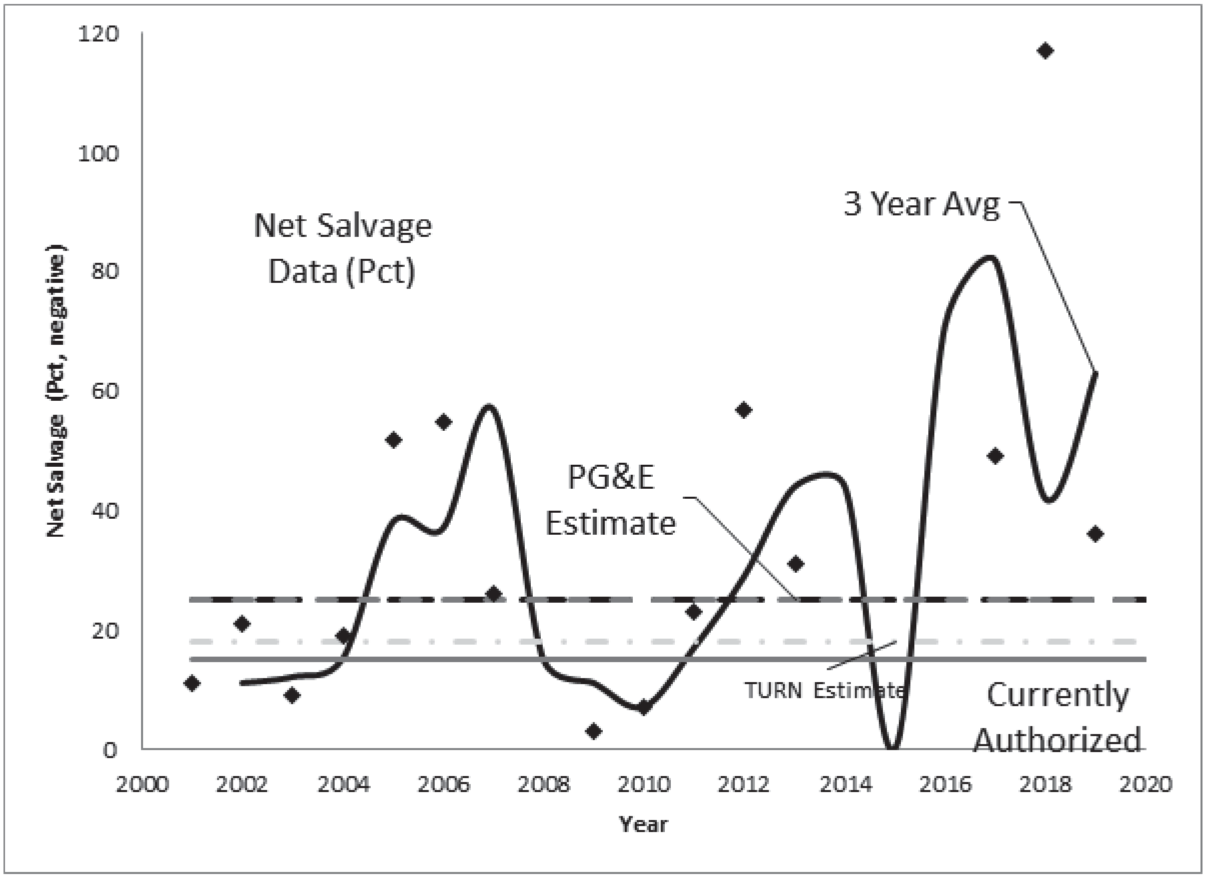
A 185 The currently authorized and proposed estimates for each party are summarized in the table below.

TABLE 12-24
COMPARISON OF CURRENTLY AUTHORIZED, PG&E, CAL ADVOCATES AND TURN NET SALVAGE ESTIMATES FOR ACCOUNT 353, WELLS

Line No.	2020 GRC Authorized Estimate	PG&E Estimate	Cal Advocates Estimate	TURN Estimate
1	(15)	(25)	(25)	(18)

Figure 12-29 provides a comparison of the historical data to each estimate.

FIGURE 12-29
ACCOUNT 352 WELLS
COMPARISON OF NET SALVAGE ESTIMATES TO HISTORICAL NET SALVAGE DATA



Q 186 Has TURN provided any support for Mr. Garrett's estimate specific to this account?

A 186 No. TURN's proposal is based on the concept of gradualism. However, because PG&E's proposal is only a 10-percentage point change in net salvage, there is no need for additional gradualism.

Q 187 Please explain why your estimate is most appropriate for this account.

A 187 As discussed above, the historical data are supportive of a negative 25 percent net salvage estimate. My recommendation is a change of 10 percentage points, which is already a gradual change. TURN has not provided sufficient justification to limit the change to this account, particularly because PG&E's proposal is already a gradual change.

7) Account 353, Lines

Q 188 Please summarize the currently authorized and proposed estimates for this account.

A 188 The currently authorized and proposed estimates for each party are summarized in the table below.

TABLE 12-25
COMPARISON OF CURRENTLY AUTHORIZED, PG&E, CAL ADVOCATES AND TURN NET SALVAGE ESTIMATES FOR ACCOUNT 353, WELLS

Line No.	2020 GRC Authorized Estimate	PG&E Estimate	Cal Advocates Estimate	TURN Estimate
1	(35)	(50)	(50)	(39)

Q 189 Has TURN provided any support for Mr. Garrett's estimate specific to this account?

A 189 No. TURN's proposal is based on the concept of gradualism. However, because PG&E's proposal is only a 15-percentage point change in net salvage, there is no need for additional gradualism.

Q 190 Please explain why your estimate is most appropriate for this account.

A 190 As shown on pages WP 12-804 and WP 12-805 of the workpapers supporting Exhibit (PG&E 10), Chapter 12, the overall net salvage percent experienced by PG&E for the period 2001 through 2020 was negative 236 percent, which is more negative than the negative 50 percent proposed. Thus, the data are supportive of PG&E's estimate. Additionally, while there is more limited data for this account, many of the removal activities would be similar to gas mains. The estimate for this account is less negative than for either gas mains account. My recommendation is a change of 15 percentage points, which is already a gradual change. TURN has not provided sufficient justification to limit the change to this account, particularly because PG&E's proposal is already a gradual change.

8) Account 367, Mains and Mains – STANPAC

Q 191 Please summarize the currently authorized and proposed estimates for this account.

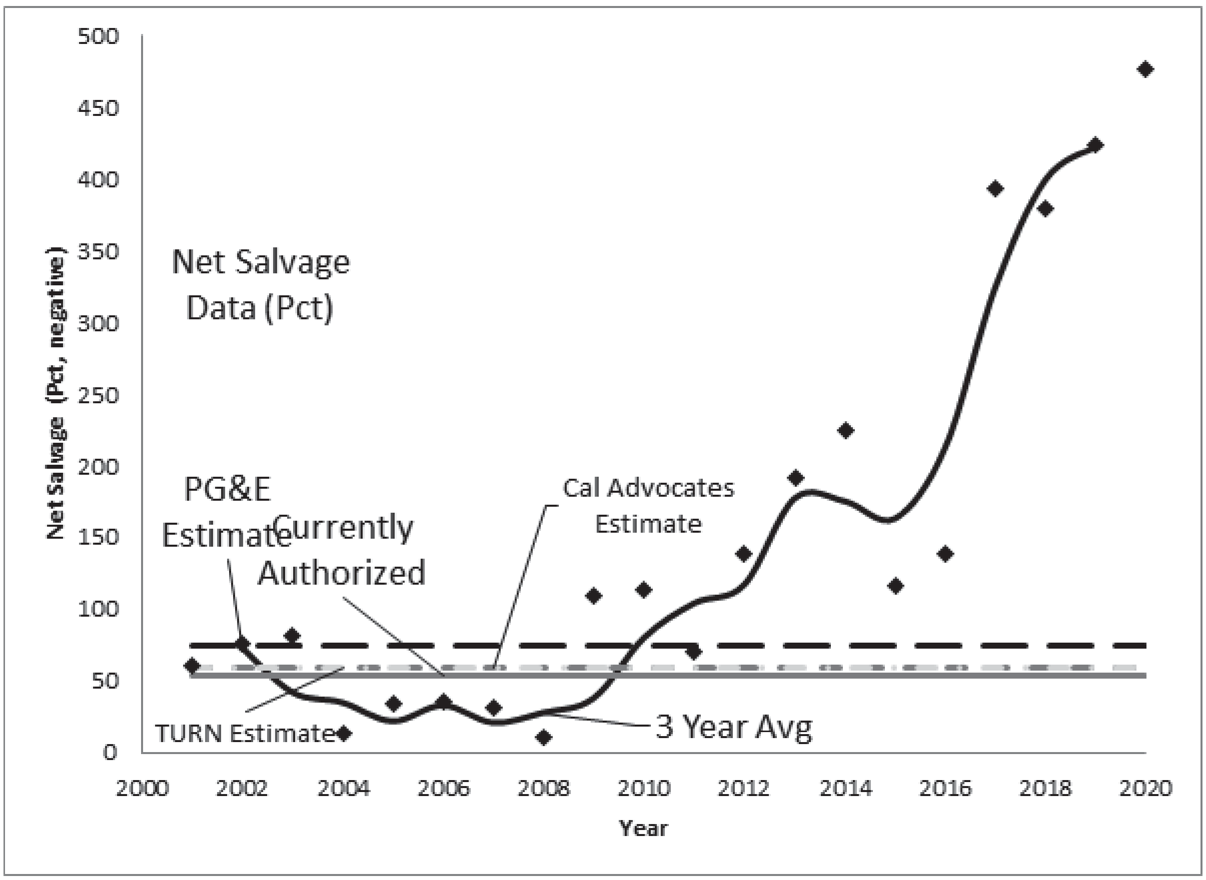
A 191 The currently authorized and proposed estimates for each party are summarized in the table below.

TABLE 12-26
COMPARISON OF CURRENTLY AUTHORIZED, PG&E, CAL ADVOCATES AND TURN NET SALVAGE ESTIMATES FOR ACCOUNT 367, MAINS

Line No.	2020 GRC Authorized Estimate	PG&E Estimate	Cal Advocates Estimate	TURN Estimate
1	(54)	(75)	(59)	(59)

Figure 12-30 provides a comparison of the historical data to each estimate.

FIGURE 12-30
ACCOUNT 367 MAINS
COMPARISON OF NET SALVAGE ESTIMATES TO HISTORICAL NET SALVAGE DATA



Q 192 Have TURN or Cal Advocates provided any support for their estimates specific to this account?

A 192 No. Their proposals are based on the concept of gradualism. However, because PG&E's proposal is only a 21-percentage point change in net salvage and because PG&E's estimate is considerably less negative than the data for at least the past 10 years, there is no need for additional gradualism. Indeed, as can be seen in the figure above, PG&E's estimate is already gradual when compared to the historical data.

Q 193 Please explain why your estimate is most appropriate for this account.

A 193 As discussed above, the historical data are supportive of a negative 75 percent net salvage estimate. My recommendation is a change of 21 percentage points, which is already a gradual change. TURN and Cal Advocates have not provided sufficient justification to limit the change to this account, particularly because PG&E's proposal is already a gradual change.

9) Account 376, Mains

Q 194 Please summarize the currently authorized and proposed estimates for this account.

A 194 The currently authorized and proposed estimates for each party are summarized in the table below.

TABLE 12-27
COMPARISON OF CURRENTLY AUTHORIZED, PG&E, CAL ADVOCATES AND TURN NET SALVAGE ESTIMATES FOR ACCOUNT 376, MAINS

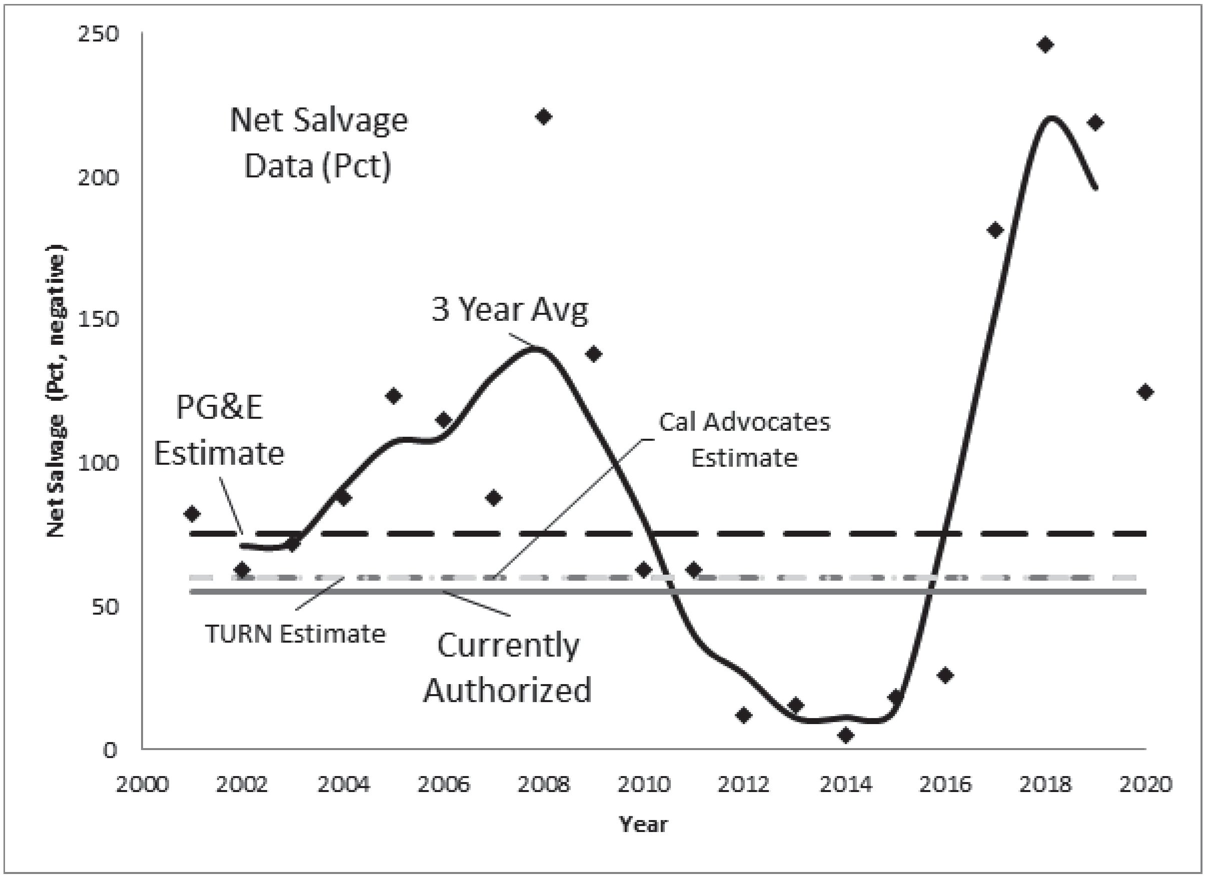
Line No.	2020 GRC Authorized Estimate	PG&E Estimate	Cal Advocates Estimate	TURN Estimate
1	(55)	(75)	(60)	(60)

Figure 12-31 provides a comparison of the historical data to each estimate. I note here that, as discussed in the 2020 GRC, the experience from 2012 through 2016 was less negative than normal[181] and not as reflective of future experience (as evidenced by the higher cost of removal in more recent years.

---

181 See A.18-12-009, HE-85: Exhibit (PG&E-10), Ch. 11 Vol 1; HE-86: Exhibit (PG&E-10), Ch. 11 Vol 2 in PG&E's 2020 GRC.

FIGURE 12-31
ACCOUNT 376 MAINS
COMPARISON OF NET SALVAGE ESTIMATES TO HISTORICAL NET SALVAGE DATA



Q 195 Have TURN or Cal Advocates provided any support for their estimates specific to this account?

A 195 No. Their proposals are based on the concept of gradualism. However, because PG&E's proposal is only a 20-percentage point change in net salvage, there is no need for additional gradualism.

Q 196 Please explain why your estimate is most appropriate for this account.

A 196 As discussed above, the historical data are supportive of a negative 75 percent net salvage estimate. My recommendation is a change of 21 percentage points, which is already a gradual change. TURN and Cal Advocates have not provided sufficient justification to limit the change to this account.

10) Account 378, Measuring and Regulating Station Equipment

Q 197 Please summarize the currently authorized and proposed estimates for this account.

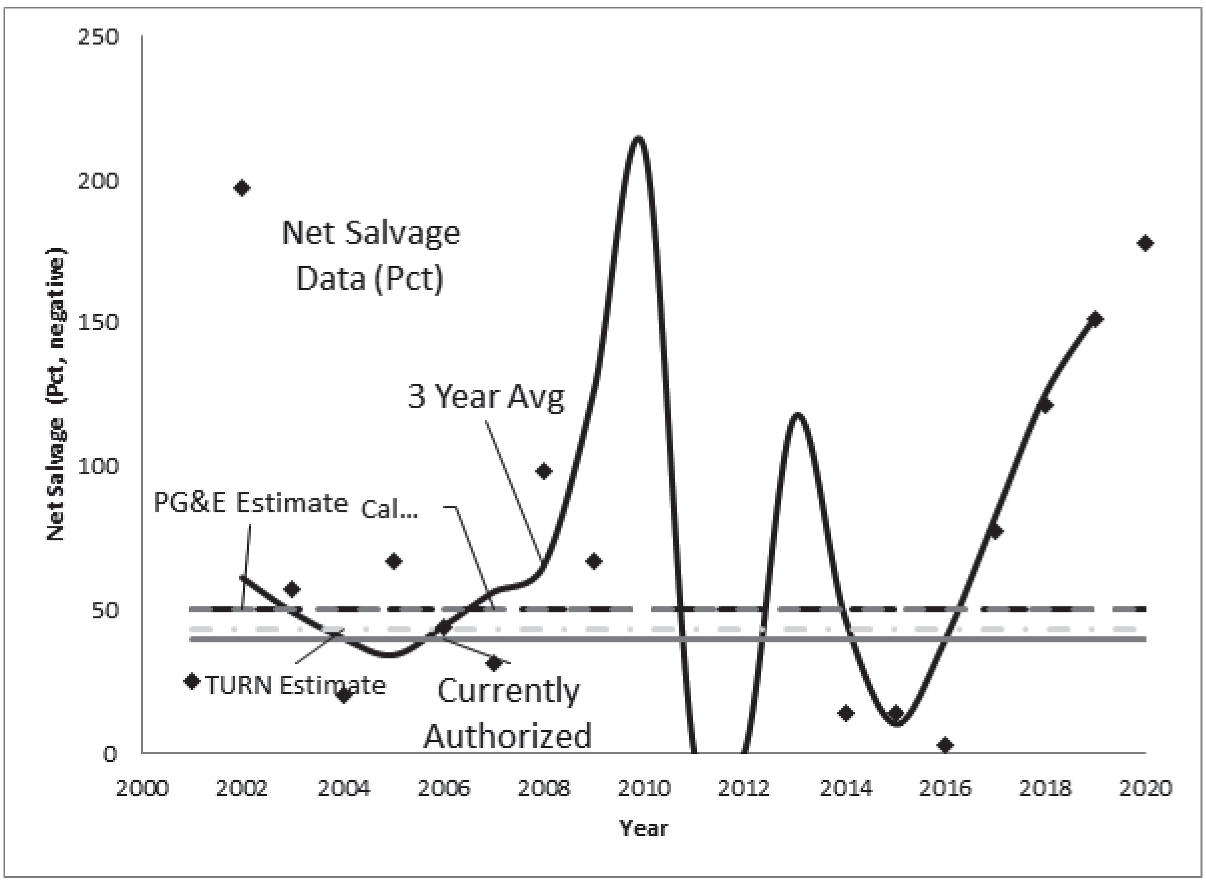
A 197 The currently authorized and proposed estimates for each party are summarized in the table below.

TABLE 12-28
COMPARISON OF CURRENTLY AUTHORIZED, PG&E, CAL ADVOCATES AND TURN NET SALVAGE ESTIMATES FOR ACCOUNT 378, MEASURING AND REGULATING STATION EQUIPMENT

Line No.	2020 GRC Authorized Estimate	PG&E Estimate	Cal Advocates Estimate	TURN Estimate
1	(40)	(50)	(50)	(43)

Figure 12-32 provides a comparison of the historical data to each estimate.

FIGURE 12-32
ACCOUNT 378 MEASURING AND REGULATING STATION EQUIPMENT
COMPARISON OF NET SALVAGE ESTIMATES TO HISTORICAL NET SALVAGE DATA



Q 198 Has TURN provided any support for Mr. Garrett's estimate specific to this account?

A 198 No. TURN's proposal is based on the concept of gradualism. However, because PG&E's proposal is only a 10-percentage point change in net salvage, there is no need for additional gradualism.

Q 199 Please explain why your estimate is most appropriate for this account.

A 199 As discussed above, the historical data are supportive of a negative 50 percent net salvage estimate. My recommendation is a change of 10 percentage points, which is already a gradual change. TURN has not provided sufficient justification to limit the change to this account.

11) Account 380, Services

Q 200 Please summarize the currently authorized and proposed estimates for this account.

A 200 The currently authorized and proposed estimates for each party are summarized in the table below.

TABLE 12-29
COMPARISON OF CURRENTLY AUTHORIZED, PG&E, CAL ADVOCATES AND TURN NET SALVAGE ESTIMATES FOR ACCOUNT 380, SERVICES

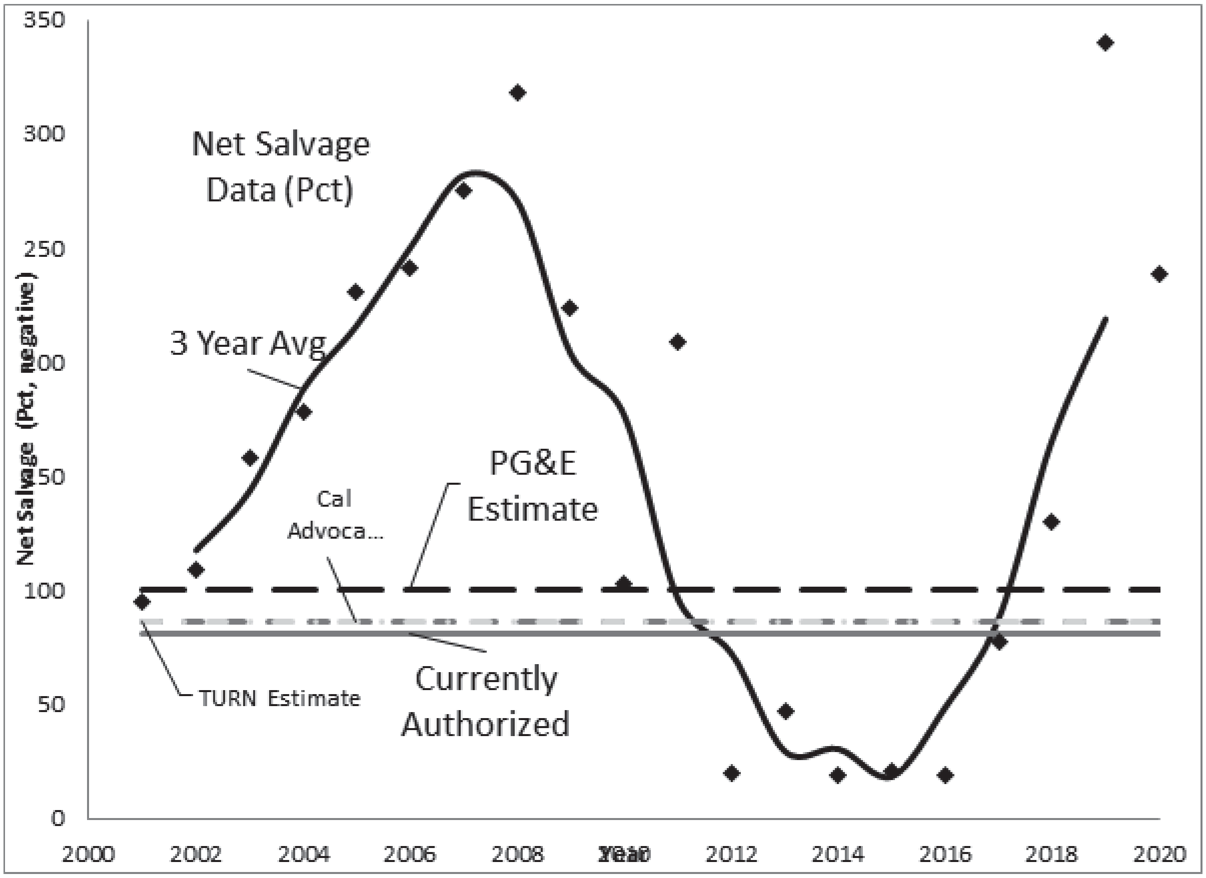
Line No.	2020 GRC Authorized Estimate	PG&E Estimate	Cal Advocates Estimate	TURN Estimate
1	(100)	(81)	(100)	(86)

Figure 12-33 provides a comparison of the historical data to each estimate.[182]

---

182 Similar to Account 376, Mains, as discussed on p. 11-841 of the workpapers supporting Chapter 11 of Exhibit (PG&E-10) in PG&E's 2020 GRC, the data from 2012-2016 was less negative than normal and less negative than should be expected going forward.

FIGURE 12-33
ACCOUNT 380 SERVICES
COMPARISON OF NET SALVAGE ESTIMATES TO HISTORICAL NET SALVAGE DATA



Q 201 Have TURN or Cal Advocates provided any support for their estimates specific to this account?

A 201 No. Their proposals are based on the concept of gradualism. However, because PG&E's proposal is only a 19-percentage point change in net salvage, there is no need for additional gradualism.

Q 202 Please explain why your estimate is most appropriate for this account.

A 202 Prior to the 2020 GRC, the authorized net salvage estimate for this account was negative 124 percent.[183] In the 2020 GRC, I noted that it was "reasonable to expect this trend [of more negative net salvage] to continue and… the data to return to levels of net salvage more similar to the years prior to 2012."[184] This has proven the case for this account, and the

---

[183] A.18-12-009, HE-80: Exhibit (PG&E-10), Ch. 11.

[184] Exhibit (PG&E-23), p. 11-100, lines 14-16.

recorded net salvage since 2017 has grown increasingly more negative. As discussed above, the historical data are certainly supportive of a negative 100 percent net salvage estimate. My recommendation is a change of 19 percentage points, which is already a gradual change. TURN has not provided sufficient justification to limit the change to this account.

5. Account 303, Software

a. TURN's Proposal to Double the Life of Software Accounts is Unreasonable and Unsupported

Q 203 What has TURN proposed for PG&E's software accounts?

A 203 For Electric Account 303.03, Gas Account 303.02 and Common Account 303.02, TURN proposes doubling the service life from 5 years to 10 years.[185] TURN does not propose a change to Common Account 303.04, for which PG&E has proposed to continue to use the current 13-year life.

Q 204 What are the currently authorized lives for these accounts?

A 204 The currently authorized lives for the three accounts for which Mr. Garrett proposes a change is five years. PG&E has not proposed to change the lives for these accounts, which have been used since the 2011 GRC.

Q 205 Do you believe it is appropriate to double the life of these software accounts?

A 205 No. There is no reason to believe that we should expect PG&E's software applications to remain in service for twice as long as the Commission has authorized in previous depreciation studies. These accounts are amortized, which means there is not data available for the statistical life analysis as there would be for depreciable accounts. Therefore, the information upon which to base the estimate for these accounts has to be based on the expectations of PG&E's personnel who are most knowledgeable about these software systems and their operations. While Mr. Garrett again attempts to disparage the input of PG&E SMEs when developing service life estimates,[186] their knowledge is far more relevant and appropriate than the general discussion Mr. Garrett provides.

---

[185] TURN-18, p. 4, Table 1.

[186] TURN-18, p. 53, lines 7-12.

Q 206 Does Mr. Garrett provide any concrete analysis that would justify doubling the service life of the software accounts?

A 206 No. Mr. Garrett discusses how PG&E failed to provide him with adequate details related to software in discovery,[187] the fact that certain types of software have longer lives (which is true, but PG&E already has a Common account 303.04 with a 13 year life and the longer-lived software assets are included in that account)[188] and that Mr. Garrett successfully argued for a 10-year software service life for one company in a state that is not California.[189] Nowhere in his testimony is there actual analysis that he has performed to demonstrate that the software assets in the PG&E accounts he proposes to change should be depreciated using a ten-year life and not the five-year life which has been approved in the last several GRCs.

Q 207 Is TURN's proposal consistent with the concept of gradualism?

A 207 No. TURN proposes to double the service life for these accounts. For the Common plant software account, which includes the majority of the investment in PG&E's 5-year software accounts, TURN's proposal results a change in the depreciation rate from the currently authorized 17.19 percent rate[190] to a rate of 5.85 percent.[191] Based on 2020 balances, TURN's proposal results in a change in depreciation expense from the $154.4 million resulting from the currently authorized rates to $37.1 million.[192] This is a $117.3 million reduction in depreciation expense, or a decrease of 76 percent. This is a significant change for a single account and is not consistent with the concept of gradualism discussed in Section C.1.e.

It is important to recognize that a small change for an account with a 5-year life has a similar result to a larger change for an asset with a longer life. For example, a change from five years to six years is a 20 percent increase in service life. In percentage terms, this is equivalent to an

---

187 See TURN-18, pp. 51-54.

188 See TURN-18, pp. 55-56.

189 See TURN-18, p. 57, lines 3-13.

190 See D.18-12-009, Appendix D for the depreciation rates authorized in the 2020 GRC.

191 See TURN-18, Exhibit DJG-4, p. 6.

192 See TURN-18, Exhibit DJG-4, p. 6.

increase in service life of eight years for an asset with a 40-year life (as this is also a 20 percent increase in service life). Thus, even an increase in life from five to six years for software is a larger change (at least in percentage terms) than the Commission considered to be appropriate in the 2014 GRC. This is particularly true because the software industry has evolved such that, particularly with more applications moving to be cloud-based, if anything we should expect shorter service lives. Mr. Garrett has no PG&E-specific information to suggest that its software lives have been too long for the past decade, much less that the service life should be doubled.

Q 208 Mr. Garrett states that the "depreciation expense PG&E proposes to charge to customers each year to recover its software costs is $158 million."[193] If PG&E had been using a 10-year life for software, would depreciation expense be significantly lower (such as proposed by Mr. Garrett)?

A 208 No. It is important to understand that, because PG&E uses amortization accounting for this account, the service life for the account impacts depreciation expense differently than it does for most other accounts (such as transmission and distribution plant accounts). For amortization accounts, assets are retired once they reach an age equal to the service life for the account. Thus, not only does the authorized service life impact the depreciation rate, but it also impacts the plant balance for the account because the authorized life determines what is retired in each year. As a result, for accounts with relatively consistent levels of annual additions, the authorized service life does not have as large of an impact on the depreciation expense as one might expect based on TURN's proposal. Instead, it is the *change* in life proposed by Mr. Garrett that results in such a large change in depreciation expense.

Q 209 Please provide an example to demonstrate this concept.

A 209 Consider a software asset class for which $200 million is added each year. If the account has a 5-year service life, then assets are retired once they reach five years of age. Once the account is mature (i.e., assets have been added and retired consistently for a number of years), the plant balance would be $1 billion and would remain at $1 billion, as the same amount

---

193 TURN-18, p. 51, lines 9-10.

would be added each year as retired each year (since each year $200 million would reach age five and be retired). The annual depreciation rate would be 20 percent (1 divided by the 5-year life) and depreciation expense would be $200 million per year (which is 20 percent multiplied by the plant balance of $1 billion).

If the account instead had a 10-year life, then the balance would be $2 billion once the account matures. Because $200 million is added each year and nothing would be retired until the tenth year, the balance would grow to $2 billion. Each year thereafter $200 million would be added and $200 million would be retired. Thus, while the depreciation rate would be 10 percent (compared to 20 percent with a 5-year life), the plant balance would be twice as high. The annual depreciation expense would be the same $200 million (10 percent multiplied by $2 billion) as the case in which a 5-year life is used. However, rate base would be higher and as a result the total cost to customers would actually be higher.

This example demonstrates that, at least for a stable account for which a similar amount is retired in each year, the impact on depreciation expense is actually not as significant as one might believe based on TURN's proposal. Had PG&E used a 10-year life for software for the past decade, then the depreciation expense for the account would be closer to what PG&E proposes than what TURN proposes. Further, rate base would be higher, increasing costs to customers.

Q 210 Given the concepts discussed above, why does TURN's proposal result in such a significant change in depreciation expense?

A 210 The reason TURN's proposal results in such a large decrease in expense is primarily due to the *change* in life, not the actual life that TURN proposes. Consider again the same example discussed above. Using the remaining life technique, a change to a longer life means that the resulting depreciation rates are lower in order to account for the higher depreciation rates used in the past (and the resultant higher accumulated depreciation). This is why Mr. Garrett proposes a depreciation rate of 5.85 percent for Common Account 303.02 even though he proposes a 10-year life (which would correspond to a 10 percent depreciation rate had PG&E always used a

10-year life for the account).[194] I note that if a 10-year life were adopted, the depreciation rate will not remain this low, but instead will increase in future studies as the level of accumulated depreciation converges towards what would be expected based on a 10-year life. Thus, TURN's proposal is not actually a long-term benefit to ratepayers but is instead a significant reduction in depreciation in the short-term that will have to be paid for by future customers.

Q 211 Why does the change in service life have such a significant impact on the resultant depreciation rate in the short-term?

A 211 As discussed above, assets in these software accounts have been retired after 5 years, consistent with the authorized 5-year service life. The only investment still on the books is five years old or less. TURN's proposal will reduce the depreciation rate based on a 10-year life. However, assets older than five years of age (and less than 10 years of age) will not be placed back into service. Thus, for the next five years, TURN's depreciation rate will be applied to a much lower plant balance than had the 10-year life been used for the past decade. Eventually, however, PG&E's plant balance will grow significantly (because assets will not be retired until they reach 10 years of age), offsetting any benefit of the lower depreciation rate TURN proposes. Thus, TURN's proposal is only a benefit for the next five years, during which customers will pay much less than their fair share.

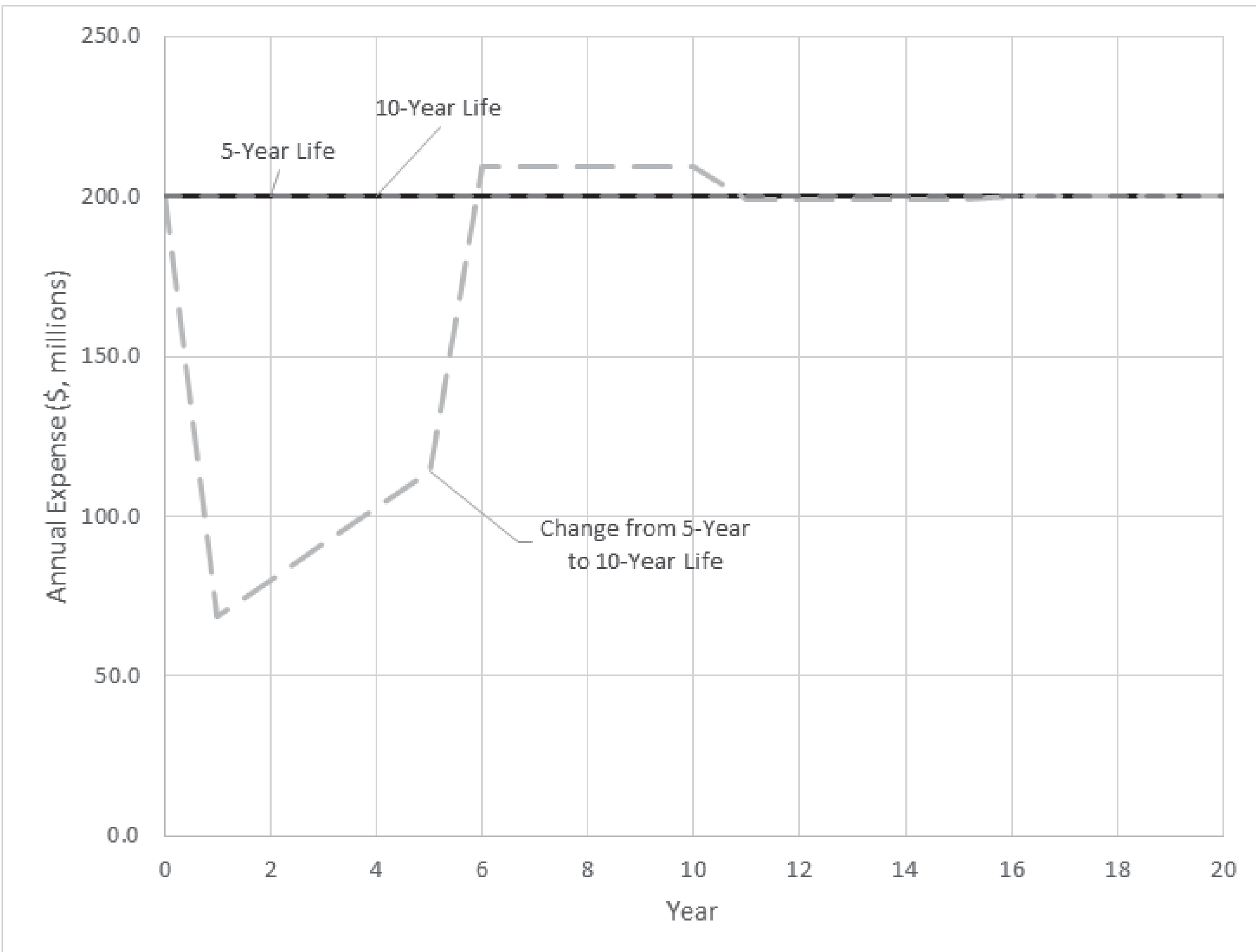
Q 212 Based on the example discussed above, please show the impact of TURN's proposal.

A 212 Figure 12-34 below provides a graph of the annual depreciation accruals for each of the scenarios described above. For the first scenario (shown as a solid black line), the account has historically had a 5-year life and continues to have a 5-year life. This scenario illustrates PG&E's proposal. For the second scenario (shown as a darker gray dashed line), the account has historically had a 10-year life and will continue to have a 10-year life. As the chart shows, the annual accrual amounts for both of these scenarios are the same. For the third scenario, which models TURN's proposal, the account has historically had a 5-year life but changes to a 10-year life. The figure

194 See TURN-18, Exhibit DJG-4, p. 6.

shows the annual accruals for each of the next 20 years after this change. As the chart shows, for TURN's proposal, depreciation accruals are initially reduced significantly, but return to the same level over time as the account balance grows.

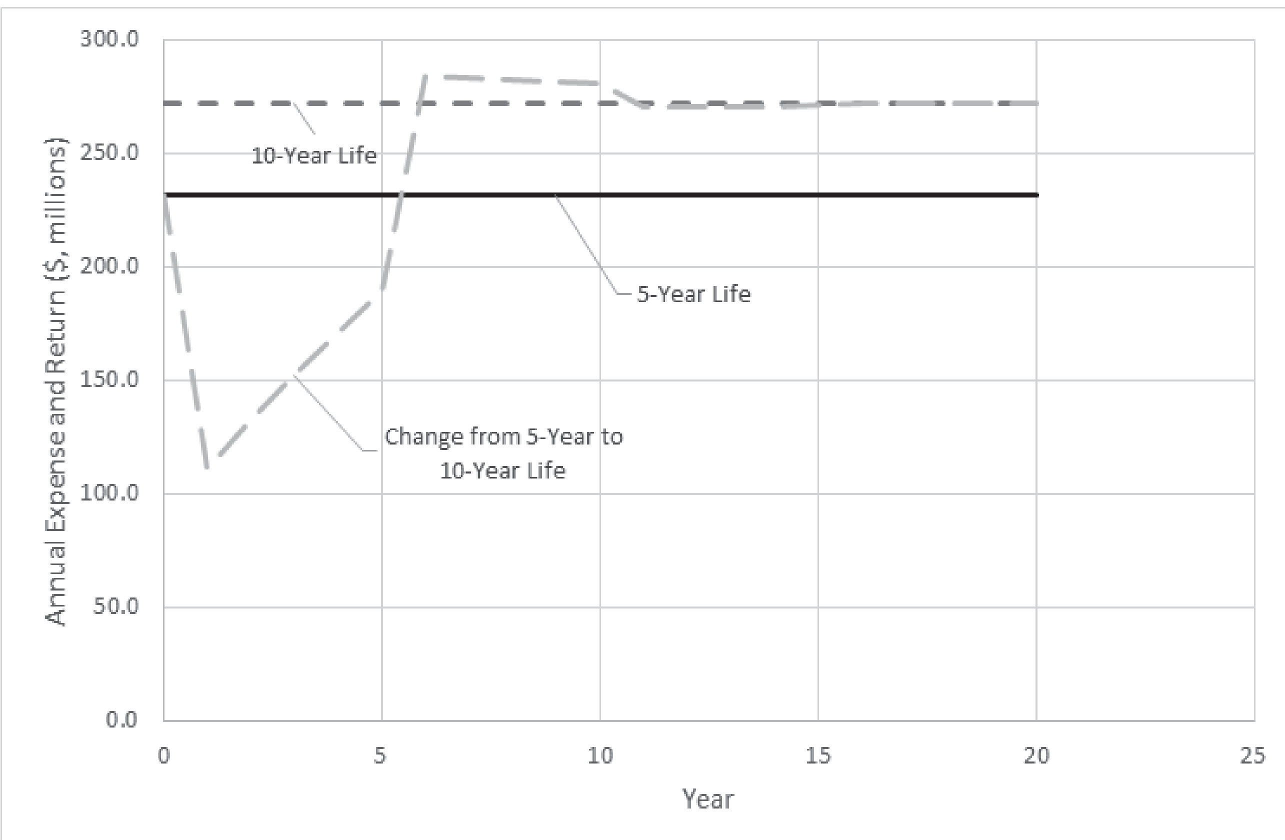
FIGURE 12-34
ANNUAL DEPRECIATION EXPENSE FOR DIFFERENT SERVICE LIVES FOR ACCOUNT 303, SOFTWARE



Q 213 Figure 11-24 compares the annual depreciation expense for each scenario. How does the return on rate base impact each scenario?

A 213 Figure 11-25 below provides the total of the annual expense and the return on rate base for the account (assuming an illustrative 8 percent rate of return). As the chart illustrates, the total cost to customers is higher using a 10-year life than a 5-year life. This occurs because the use of a 10-year life results in a higher rate base, even though the depreciation expense is the same. The chart also shows that TURN's proposal, while resulting in a short-term reduction, ends up resulting in a higher cost to customers after the conclusion of this short-term reductions.

FIGURE 12-35
TOTAL OF ANNUAL EXPENSE AND RETURN ON RATE BASE FOR DIFFERENT SERVICE LIVES FOR ACCOUNT 303, SOFTWARE



Q 214 Based on this analysis, what can you conclude about each proposal?

A 214 There are multiple conclusions that are demonstrated by this example. First, PG&E's historical use of a 5-year life for software has not been harmful to customers and in fact, because rate base is lower, results in a lower cost to today's customers than had a 10-year life been used. Second, TURN's proposal only results in a short-term reduction in rates and will eventually lead to higher costs for future customers. Finally, the extreme change in depreciation resulting from TURN's proposal provides a significant benefit to customers who receive service over the next few years but will increase costs thereafter. TURN's proposal, therefore, does not result in an equitable allocation of costs. It also follows that even if the Commission were to determine that a longer life was appropriate for this account, a more gradual change would be appropriate, so as to not unfairly benefit customers over the next few years at the expense of future customers.

Q 215 What reasons does Mr. Garrett provide for his proposal to double the lives for these accounts?

A 215 Mr. Garrett provides a discussion of various types of software assets that could last longer than five years and concludes that PG&E's software assets will, on average, last longer than five years. He also provides citations to two other cases. However, Mr. Garrett's discussion is largely the same as I have seen in his testimony in other cases and he fails to acknowledge important differences between PG&E's software accounts and those of other utilities.

Q 216 Does PG&E use a 5-year life for all of its software assets?

A 216 No. PG&E also has an account that has a significantly longer 13-year life. This account has a balance of more than $350 million and includes larger software applications such as its Customer Information System. Much of Mr. Garrett's discussion is focused on his argument that larger software systems can have longer lives than five years. However, he fails to acknowledge that this is already accounted for by the fact that PG&E has a software account with a much longer life and that about a third of PG&E's software investment is in this longer account with a longer service life. If Mr. Garrett believes that some of PG&E's software assets will have longer lives, he could have reviewed the investment in this account and proposed to move assets to the longer-life software account. However, he did not do so and instead proposes to double the life for all assets in the 5-year software accounts, which are different types of systems than those he discusses in his testimony.

Q 217 Does the 5-year life for these accounts mean that no assets will have a longer life than five years?

A 217 No. The 5-year life is an ASL. Some assets may have longer lives but some will also have shorter lives. Further, although some applications may last longer than five years, enhancements and upgrades will be in service for a shorter period of time. Additionally, PG&E's computer hardware has a five-year service life, which aligns with the software life. Given these considerations, as well as that larger software systems already have a much longer life, a 5-year life continues to be reasonable for the assets in these accounts.

The reasonableness of the 5-year life for these accounts is also discussed in more detail in the next section. Further, PG&E's expectation is that, if anything, the service lives for software will be shorter in the future as the industry evolves. Mr. Garrett's proposal moves in the opposite direction of what would be appropriate.

Q 218 Are Mr. Garrett's discussions of the potential for longer lives for larger enterprise systems[195] convincing?

A 218 No. First, his discussion effectively ignores that PG&E already has an account with a much longer service life that includes larger software systems. Second, while Mr. Garrett makes general reference in the discussion on page 55 of Exhibit TURN-18 to the longer lives of certain types of software systems, he fails to acknowledge that these types of systems are typically upgraded periodically. These upgrades have shorter service lives than the overall system, which reduces the overall average life.

Q 219 Mr. Garrett discusses Enterprise Resource Planning software, and SAP in particular, as examples of software systems that have longer lives.[196] Is SAP in any of PG&E's 5-year software accounts?

A 219 No. As discussed in Exhibit (PG&E-24), Chapter 17 of PG&E's 2020 GRC, when SAP was originally implemented it was not capitalized and, as a result,

---

195 TURN-18, p. 55, lines 13-19.

196 TURN-18, pp. 55-56.

is not in any of the accounts at issue. There are enhancements and upgrades to SAP included in some of PG&E's software accounts. However, a 5-year life is appropriate for many of these investments, since they are periodic upgrades, rather than the full costs of implementing SAP. As a result, none of the arguments Mr. Garrett makes regarding SAP are relevant to PG&E.

Q 220 Do Mr. Garrett's discussions of other cases provide support for his proposal? [197]

A 220 No. Mr. Garrett fails to acknowledge important differences or distinctions between those cases and what he is proposing in the instant case. First, Mr. Garrett cites to a Florida Power & Light (FPL) case in which FPL requested a longer life for its SAP software system.[198] While this is correct *for this software system*, FPL continues to use a 5-year life for most of its software applications, including many newer applications. Thus, FPL's practice is similar to PG&E's in that FPL uses a 5-year life for most software assets but uses a longer life for certain longer-life applications. In contrast, what Mr. Garrett proposes is quite different from FPL, as he proposes a 10-year life for most software applications and a 13-year life for other systems, but no account with a five-year life.

Q 221 Is Mr. Garrett aware of the differences between his proposal and the service lives used by FPL?

A 221 No, at least not based on his response to discovery. Mr. Garrett does not know that FPL uses a 5-year life for most software.[199] This is fairly surprising given the plain language cited by Mr. Garrett states indicates that FPL uses a 5-year life for software and that the 20-year life was for a specific software system.[200] The fact that Mr. Garrett is unaware of FPL's actual practices, and that most of FPL's software systems use the same

---

197 TURN-18, pp. 56-57.

198 TURN-18, p. 56, lines 2-18.

199 See TURN's response to Data Request PGE_TURN006-Q02, dated 6/27/22 in Appendix A, at the end of this exhibit.

200 See TURN-18, p. 56, lines 9-16. Specifically, the citation states that "FPL's policy for accounting for new software requires…amortization on a straight-line basis over a period of five years" and that FP&L's request was "to extend the amortization period of **this** software system from five to twenty years." (Emphasis added).

5-year life as PG&E's 5-year software accounts, means that his analysis and support for his proposal based on FPL's case is inaccurate. Instead, FPL's approach for software is more supportive of PG&E's proposal.

Q 222 Does Mr. Garrett cite to any other cases in support of his proposal?

A 222 Yes. Mr. Garrett also cites to a PSO case in Oklahoma.[201] However, he fails to acknowledge in his testimony the important distinction that PSO had proposed a 5-year life for all software applications, whereas PG&E has a 5-year life for many applications but a longer 13-year service life for larger applications. Thus, Mr. Garrett's proposal in the instant case is not the same as PSO's proposal in the PSO case he cites.

b. PG&E's Response to Claims Made by TURN

Q 223 Are there any other claims made by TURN/Garrett that PG&E wishes to address?

A 223 Yes. PG&E responds to several additional claims made by TURN witness Garrett in this section, which is sponsored by PG&E witness Ajay Pathak.

Q 224 TURN characterizes the information provided by PG&E on its software accounts as "does not provide actual support for its proposed five-year service life … ."[202] Do you agree with this statement?

A 224 No. As a part of opening workpapers, PG&E provided a robust work paper package that provides an analysis of software assets supported by Information Technology (IT) specific detail. First, the analysis starts with a description of the differences between "software assets," "software applications," and "software products." This discussion is accompanied by a high-level diagram that shows the various layers of a generic, high-level technology stack and multiple areas where software assets appear.[203] Second, PG&E continues the analysis by describing the importance of replacing aging assets and keeping current with asset health to prevent impacts to operations. IT further illustrates the relationship between software and hardware assets within each technology solution by IT asset family, and the anticipated useful lives of the software assets in the

---

201 TURN-18, p. 57, lines 1-13.

202 TURN-18, p. 54, lines 6-7.

203 Exhibit (PG&E-7) (Feb. 28, 2022), WP 8-123.

"Relevance to Software Asset Class" section of each asset family.[204] Third, PG&E further differentiates software and hardware assets by establishing specific Software/Hardware (SW/HW) groups by function and relating them to expected software useful lives.[205] Finally, PG&E concludes the analysis by showing a selection of investment capital additions for both software asset class 302 and 304 identified by SW/HW group.[206] In addition to the work papers described above, PG&E provided data responses that addressed various details of software asset investments – from each software component used to build individual technology solutions; individual operational assessments of software useful lives, and recent studies on software useful lives provided by external consultants. [207]

Q 225 TURN states that in the data responses provided by PG&E, the records that were provided "show a five year life based on the earlier-adopted service life. rather than the actual experienced services life."[208] Do you agree with this statement? Discuss.

A 225 No, I do not. While the records cited in the responses provided to TURN were informed by the "vintage retirement/amortization process" for this asset class, those data points were further reviewed, expanded and validated by the software application owners. The lives discussed in the workpapers noted above were based on this review, and not simply a restatement of adopted service lives as TURN incorrectly asserts.

Q 226 TURN describes PG&E's software assets as "large enterprise software systems" that "perform reliably over a long period of time."[209] Do you agree with this characterization of the software asset investments in PG&E's software account? Discuss.

---

204 Exhibit (PG&E-7) (Feb. 28, 2022) WP 8-124 through 8-129.

205 Exhibit (PG&E-7) (Feb. 28, 2022) WP 8-129 through 8-130.

206 Exhibit (PG&E-7) (Feb. 28, 2022) WP 8-131 through 8-132.

207 PG&E's response to Data Request TURN_026-Q24, dated 10/20/21 and attachment TURN_026-Q24Atch01, TURN_26-Q24Atch02, TURN_26-Q24Atch03, and Confidential attachment TURN_26-Q24Atch04CONF; PG&E's response to Data Request TURN_105-Q03, TURN_105-Q04, dated 2/15/22 and attachment TURN_026-Q03Atch01 in Appendix A, at the end of this exhibit.

208 TURN-18, p. 54, lines 19-20

209 TURN-18, p. 55, lines 6-9.

A 226 No, I do not. In the work papers that were cited above, PG&E describes the wide variety of software assets in each asset family.[210] Some are simple software code efforts designed to support a hardware asset or manage multiple devices and associated data; others are software code solutions that act as interfaces between two separate software systems; still others are large, complex software code changes that update systems with new functionality. The type of software investment is as varied as the business needs that they support. For each of these types of software assets, PG&E has provided a range of expected useful lives based on usage and expected industry technology innovations.

Q 227 TURN claims that "while a five-year average life may have been appropriate for older, more basic software systems, it does not reflect the much longer service life of newer, more complex systems."[211] Do you agree? Discuss.

A 227 No, I do not. First, software systems should not be confused with software assets. Software systems are comprised of various software and hardware assets. Second, an older system in many aspects can be much more complex than a newer system. Older systems are typically difficult to use and maintain because the technology ages out and cannot support users' evolving needs. Third, new systems are not typically designed to be complex as that is not conducive to user needs. Most new systems are designed to be modular, agile and cloud first. Finally, many key software vendors, like SAP, have already signaled intent to move all of their products and services to the cloud. This will effectively push PG&E to consider shorter software lives in order to take advantage of the technological innovations offered by cloud technology solutions.

D. Conclusion

Q 228 Does this conclude your rebuttal testimony?

A 228 Yes, it does.

---

[210] Exhibit (PG&E-7) (Feb. 28, 2022) WP 8-124 through 8-129.

[211] TURN-18, p. 56, lines 17-18.

PACIFIC GAS AND ELECTRIC COMPANY

CHAPTER 12A

REBUTTAL TESTIMONY OF

DAVID B. SAWAYA

GAS THROUGHPUT DATA

PACIFIC GAS AND ELECTRIC COMPANY
CHAPTER 12A
REBUTTAL TESTIMONY OF
DAVID B. SAWAYA
GAS THROUGHPUT DATA

TABLE OF CONTENTS

PACIFIC GAS AND ELECTRIC COMPANY
CHAPTER 12A
REBUTTAL TESTIMONY OF
DAVID B. SAWAYA
GAS THROUGHPUT DATA

A. Introduction

Q 1 Please state your name and the purpose of this rebuttal testimony.

A 1 My name is David Sawaya. This testimony responds to the direct testimony of Maurice Brubaker on behalf of the Indicated Shippers and Northern California Generation Coalition (IS/NCGC).[1] Mr. Brubaker is the only witness who specifically addresses the gas throughput data I provided in Chapter 12A of Exhibit (PG&E-10). In Chapter 12 of Exhibit (PG&E-23), PG&E witness Ned Allis addresses the testimony of Mr. Brubaker, TURN and Cal Advocates on depreciation. I summarize Mr. Brubaker's positions in Section B below.

B. Summary of Issues

Q 2 Please provide a summary of parties' policy positions to which you are responding.

A 2 This testimony responds to IS/NGCC's testimony concerning the following allegations in Mr. Brubaker's testimony:

- "PG&E has not adequately supported its throughput projections"[2]
- "PG&E has not developed and proposed a series of actions designed to result in a reduction in gas usage."[3]
- "PG&E does not take into account alternative uses of its distribution system"[4]

Each issue is discussed in Section C below.

---

[1] IS/NCGC-1.

[2] IS/NCGC-1, p. 3, lines 9-10.

[3] IS/NCGC-1, p. 3, lines 11-12.

[4] IS/NCGC-1, p. 9, lines 16-17.

C. PG&E's Response

1. PG&E conducted an analysis of six throughput projections from two different sources to reach a conclusion as to which throughput forecast to use within its UoP proposal

Q 3 Did PG&E limit its examination to throughput forecasts developed by Energy and Environmental Economics, Inc. ("E3") in developing its UoP proposal?

A 3 No. As noted in Opening Testimony, PG&E considered two forecasts from the 2020 California Gas Report (CGR)[5] and four gas throughput scenarios from E3.[6]

Q 4 What is the purpose of the CGR and what factors does the report analyze in relation to forecast gas throughput?

A 4 As noted by the Commission in a 1995 decision directing gas utilities to produce the CGR, the "projections in the CGR are for long-term planning."[7] The 2020 CGR examines, in detail, a variety for drivers of gas throughput including energy efficiency, building electrification resulting from fuel switching from natural gas appliances to electric, an increase in greenhouse gas (GHG)-free electric generation resources, and warming temperatures due to climate change.

Q 5 Did PG&E elect to utilize a CGR forecast for its UoP proposal? If not, why?

A 5 As noted in opening testimony, "[d]ue to its intended use in informing long-term gas system planning, PG&E considered the 2020 CGR 'average year demand' forecast as the primary source of throughput assumptions to be used in the UoP model."[8] However, PG&E did not ultimately select the CGR's "average year demand" forecast because the 2020 CGR's forecast timeframe, which only extends to 2035, was not adequate for the UoP methodology.

Q 6 What alternative throughput projection did PG&E conclude should be used?

---

5 California Gas and Electric Utilities, 2020 California Gas Report (Aug. 24, 2020), at: <https://www.socalgas.com/sites/default/files/2020-10/2020_California_Gas_Report_Joint_Utility_Biennial_Comprehensive_Filing.pdf> (as of July 1, 2022.

6 Exhibit (PG&E-10) (Feb. 28, 2022), p. 12A-2, line 5 to p. 12A-3, line 16.

7 Decision (D.) 95-01-039, 1995 Cal. PUC LEXIS 38. *3; 58 CPUC2d 552.

8 Exhibit (PG&E-10) (Feb. 28, 2022), p. 12A-4, lines 5-7.

A 6 PG&E initially determined that “E3’s medium-high electrification scenario” was the most appropriate substitute for the “2020 CGR ‘average year demand’ forecast” because it has the required timeframe for the UoP methodology and it has positive correlation of .994 with the “2020 CGR ‘average year demand’ forecast” during the comparable time frame.[9]

Q 7 What throughput projection did PG&E ultimately use for its UoP methodology and why?

A 7 Ultimately, PG&E elected to use “E3’s medium electrification scenario,” which has a positive correlation of .988 with the “2020 CGR ‘average year demand’ forecast” during the comparable time frame.[10] To understand the reasons for this decision, please refer to Chapters 11 and 12 of Exhibit (PG&E-10) and Exhibit (PG&E-23). As PG&E witness Ned Allis discusses in Chapter 12 of Exhibit (PG&E-23), the use of the medium electrification scenario for the UoP Method results in lower depreciation expense than the medium-high electrification scenario.[11]

2. Proposed regulatory action by State and Regional Agencies will substantially increase building electrification thereby reducing gas throughput

Q 8 IS/NGCS states that a major challenges for building electrification is the replacement of “appliances that are behind the customer’s meter.”[12] Are there any proposed regulatory actions that would be expected to increase the conversion of gas appliances to electric appliances?

A 8 Yes. The California Air Resources Board (CARB) and the Bay Area Air Quality Management District (BAAQMD)[13] are developing rules that would effectively ban the sale of gas space and water heating appliances at a future date. The proposed rules from CARB and BAAQMD, if approved, would go into effect in 2030 and 2027, respectively.

---

9 Exhibit (PG&E-10) (Feb. 28, 2022), p. 12A-4, lines 21-24.

10 Exhibit (PG&E-10) (Feb. 28, 2022), p. 12A-4, line 21 to p. 12A-5, line 5.

11 *See,* for example, the discussion in Section C.2.b of Chapter 12 of Exhibit (PG&E-23).

12 IS/NCGC-1, p. 6, lines 5-6.

13 BAAQMD, Rules 9-4 and 9-6 Building Appliances (updated Jan. 21, 2022), available at <https://www.baaqmd.gov/rules-and-compliance/rule-development/building-appliances< (as of July 1, 2022).

3. PG&E's activities are not the driver of projected throughput decline on the gas distribution system

Q 9 IS/NGCS states that "PG&E has not developed and proposed a series of actions designed to result in a reduction in gas usage."[14] Are PG&E's activities related to decarbonization a consideration in the throughput projections PG&E considered for its depreciation proposal?

A 9 No. The projections that PG&E considered for use within the units of production (UoP) depreciation methodology are system-level gas throughput forecasts. The forecasts and scenarios considered do not assume that PG&E's decarbonization activities are a material driver of forecast future gas throughput. Instead, the projections incorporate the impact of external forces on gas throughput, including a warming climate, customer decisions, and government policies and regulations that result in electrification and/or a change in gas usage.

4. The introduction of non-fossil gases, such as renewable natural gas (RNG) and hydrogen, are not expected to impact throughput on PG&E's gas system

Q 10 IS/NGCS states that PG&E has not considered alternative uses of its gas distribution system to transport RNG and hydrogen.[15] Would you expect the introduction RNG and hydrogen into PG&E's distribution system to materially impact overall throughput?

A 10 No. The introduction of RNG and hydrogen into PG&E's gas distribution system would not be expected to increase demand for gas or materially impact gas throughput on the distribution system. Rather, the introduction of alternative gases into the gas system would be expected to displace existing fossil gas throughput because alternative gases would not increase a customer's energy needs.

Q 11 Does this conclude your rebuttal testimony?

A 11 Yes, it does.

---

[14] IS/NCGC-1, p. 3, lines 11-12.

[15] IS/NCGC-1, p. 9, lines 16-22.

PACIFIC GAS AND ELECTRIC COMPANY

CHAPTER 13

INCOME AND PROPERTY TAXES

THIS CHAPTER HAS NO REBUTTAL

(PG&E-23)

PACIFIC GAS AND ELECTRIC COMPANY

CHAPTER 14

REBUTTAL TESTIMONY OF

PAUL HUNT

WORKING CASH

PACIFIC GAS AND ELECTRIC COMPANY
CHAPTER 14
REBUTTAL TESTIMONY OF
PAUL HUNT
WORKING CASH

TABLE OF CONTENTS

PACIFIC GAS AND ELECTRIC COMPANY
CHAPTER 14
REBUTTAL TESTIMONY OF
PAUL HUNT
WORKING CASH

A. Introduction

Q 1 Please state your name and the purpose of this rebuttal testimony.

A 1 My name is Paul Hunt. This testimony responds to the direct testimony of the Public Advocates Office at the California Public Utilities Commission (Cal Advocates)[1] and The Utility Reform Network (TURN)[2] related to working cash. I summarize these parties' positions in Section B below.

B. Summary of Issues

Q 2 Please provide a summary of parties' policy positions to which you will be responding.

A 2 This testimony responds to parties' testimony concerning the following issues: (1) PG&E's need for working cash; (2) PG&E's projection of customer deposits in 2023 and the appropriate ratemaking for such deposits; (3) the revenue lag incorporated in calculating working cash; and (4) the expense lags for federal and state income taxes and goods and services incorporated in working cash calculations. Each issue is discussed in Sections C and D below.

C. Need for Working Cash

Q 3 TURN claims that PG&E will have "excess cash" from its rate-neutral securitization that "should be available to defray PG&E's working cash needs."[3] How do you respond to this claim?

A 3 TURN is mistaken. There will not be any significant cash remaining from the rate-neutral securitization that can be employed to offset PG&E's working cash requirement. It is surprising that TURN argues otherwise, since, as a party to the rate-neutral securitization application, A.20-04-023, and PG&E's

---

1 CA-15.

2 TURN-19E.

3 TURN-19E, p. 21, lines 17-18.

related financing order application, A.21-01-004,[4] it has information about the disposition of the securitization funding.

TURN's argument rests on an incomplete reading of PG&E's securitization application and on a single sentence in PG&E's 2022 first quarter Form 10-Q, filed with the Securities and Exchange Commission, dated April 28, 2022. With respect to the securitization application, it stated:

> The proposed Securitization would enable PG&E to retire $6 billion of temporary utility debt that will be used to pay wildfire claims on emergence *and* to accelerate the final payment to wildfire victims as described in PG&E's Plan…[5]

The above referenced sentence in PG&E's 2022 first quarter Form 10-Q, in its entirety, reads as follows: "*Among other uses,* as a result of the proposed transaction, the Utility would retire $6.0 billion of Utility debt."[6] On the same page of Form 10-Q there is a reference to the financing of "$7.5 billion of the Utility's 2017 catastrophic wildfire costs and expenses"[7] in connection with the securitization.

In the rate-neutral securitization proceeding, PG&E provided this breakdown of uses of the proceeds from the $7.5 billion securitization:[8]

- $6.0 billion – retirement of temporary utility debt;
- $1.35 billion – funding remaining obligations to the Fire Victim Trust; and
- $0.15 billion – issuance costs and accrued interest.

In May 2022, PG&E issued the first series of recovery bonds authorized by the CPUC decisions in the securitization application and the financing

---

4 In fact, TURN's intervenor compensation requests filed in these two dockets indicate that Ms. Dowdell, TURN's witness on working cash, worked a total of 351.5 hours on A.20-04-023 and 4.25 hours on A.21-01-004. See, A.20-04-023, TURN's Intervenor Compensation Claim (Oct. 5, 2021), Attachment 2, J. Dowdell section; and, A.21-01-004, TURN's Intervenor Compensation Claim (Oct. 7, 2021), Attachment 2, J. Dowdell section.

5 A.20-04-023, PG&E's Application for Administration of Stress Test Methodology, et al. (Apr. 30, 2020), p. 3 (emphasis added).

6 PG&E's SEC Form 10-Q, 2022 First Quarter (Apr. 28, 2022), p. 33 (emphasis added), <https://investor.pgecorp.com/financials/sec-filings/sec-filings-details/default.aspx?FilingId=15760855> (as of June 28, 2022).

7 PG&E's SEC Form 10-Q, 2022 First Quarter (Apr. 28, 2022), p. 33. See fn. 6 for link to the document.

8 A.20-04-023, PG&E's Post-Hearing Opening Brief (Jan. 15, 2021), pp. 9-10.

application.[9] The first series of recovery bonds has a face amount of $3.6 billion, so it is only part of the full securitization. The prospectus for these bonds states in part:

> In accordance with the financing order, PG&E will use the ultimate proceeds it receives from the sale of the recovery property to reimburse itself for previously incurred recovery costs, including the retirement of a portion of the $6.0 billion of related "Temporary Debt" currently outstanding … *and* a portion of loans outstanding under the Utility Revolving Credit Agreement.[10]

From the information presented above, it should be abundantly clear that TURN's claims regarding the availability of excess cash from PG&E's securitization are incorrect and the Commission should disregard them. Correspondingly, the Commission should ignore TURN's allegation of "roughly $24 million per year … accruing to shareholders … ."[11] The facts above indicate that PG&E will fully use the funding from the recovery bond proceeds to recover catastrophic wildfire costs and other recovery costs and to finance or refinance the same.[12] PG&E needs the working cash component of rate base it is requesting in this case for its business operations as in any other GRC.

D. PG&E's Response to Parties' Specific Policy Positions

1. Customer Deposits (Cal Advocates)

Q 4 What is the first policy position you are addressing?

A 4 The first issue I will address is Cal Advocates' position on customer deposits.

Q 5 What are the differences between PG&E's position on customer deposits and Cal Advocates' position?

---

9 D.21-04-030, p. 93, Ordering Paragraph (OP) 17; D.21-05-015, p. 98, par. ii and iii, OP 1.

10 Prospectus, $3,600,000,000 Senior Secured Recovery Bonds, Series 2022-A; Pacific Gas and Electric Company, Sponsor, Depositor and Initial Servicer; PG&E Wildfire Recovery Funding LLC, Issuing Entity (May 3, 2022), p. 138 (emphasis added), <https://d18rn0p25nwr6d.cloudfront.net/CIK-0000075488/af09330c-c0b8-4cdd-b8e0-022aabf8ff70.pdf> (as of June 27, 2022).

11 TURN-19E, p. 22, lines 7-8.

12 D.21-05-015, pp. 97-98, OP 1.

A 5 There are two differences, which I will address in turn: (1) the correct projection of customer deposits for 2023, and (2) the correct ratemaking treatment for customer deposits.

a. Forecast of Customer Deposits

Q 6 What is the difference between PG&E's position on the 2023 level of customer deposits and Cal Advocates' position?

A 6 PG&E projects an average customer deposits balance for 2023 of $81.5 million.[13] In contrast, Cal Advocates argues for a higher balance of $100 million.[14]

Q 7 Do you agree with Cal Advocates' position? Please discuss.

A 7 No, PG&E does not support Cal Advocates' position on this issue. Cal Advocates states that Covid-19 customer deposit restrictions ended on June 30, 2021[15] and that a projection of PG&E's customer deposits for 2023 should be based on PG&E's average level of customer deposits for 2019.[16]

PG&E updated its 2023 projection of customer deposits in October 2021 based on data through the end of 2020 in a data response to Cal Advocates.[17] After PG&E issued the data response, its customer deposits continued to fall and from May 2021 through May 2022, they have averaged $78.63 million.[18] Based on current trends, PG&E's projection of $81.5 million for 2023 will likely overstate the true level of customer deposits

---

13 Exhibit (PG&E-10) (Feb. 28, 2022), p. 14-15, lines 19-19.

14 CA-15, p. 31, line 2.

15 This is correct for nonresidential customer deposits but it is not correct for residential customer deposits. PG&E Gas Rule No. 7, <https://www.pge.com/tariffs/assets/pdf/tariffbook/GAS_RULES_7.pdf>, and PG&E Electric Rule No. 7 <https://www.pge.com/tariffs/assets/pdf/tariffbook/ELEC_RULES_7.pdf>, as of June 28, 2022.

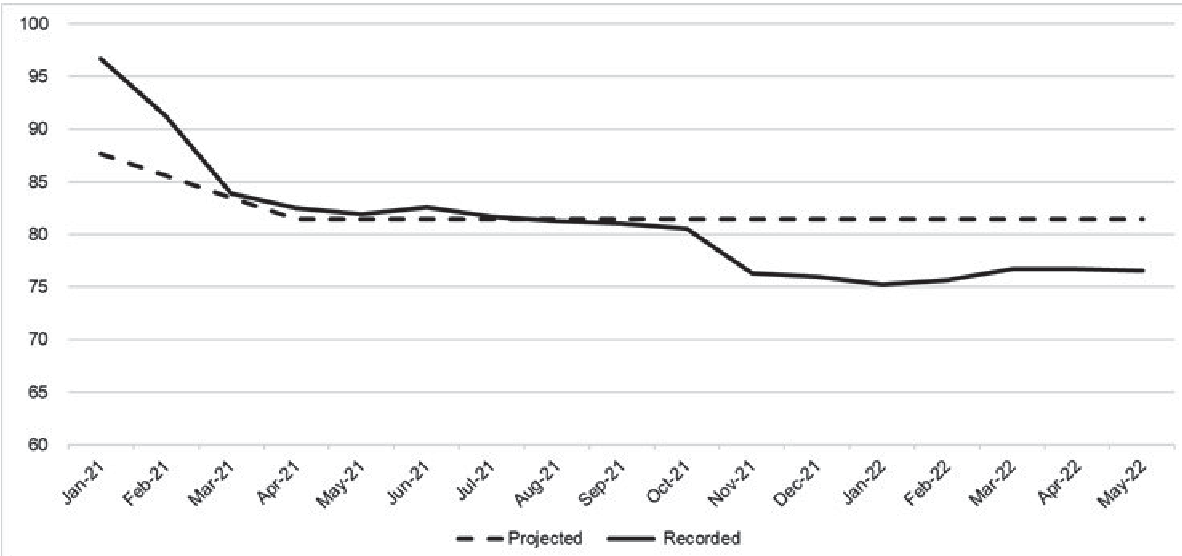
16 CA-15, p. 30, line 24 to p. 31, line 2.

17 PG&E's response to Data Request CalAdvocates_083-Q01, dated 10/13/21 in Appendix A, at the end of this exhibit. See also Exhibit (PG&E-10) (Feb. 28, 2022), WP 14-154, line 13.

18 See Exhibit (PG&E-23), WP 14-1. This average can be calculated from the data in column C.

in 2023. The decline in PG&E's customer deposits in 2021 and 2022 is shown in the following chart.

FIGURE 14-1
2021-2022 CUSTOMER DEPOSITS
(MILLIONS OF DOLLARS)



Q 8 How should the Comission set the forecast level of customer deposits in this case?

A 8 PG&E recommends that the Commission adopt PG&E's projection of $81.5 million for 2023.

b. Ratemaking Treatment for Customer Deposits

Q 9 How does PG&E recommend the Comission adjust its 2023 test year revenue requirement to account for customer deposits?

A 9 PG&E recommends that the Commission adopt PG&E's revenue requirement reduction of $2.831 million for 2023.[19]

Q 10 What is the difference between PG&E's position on the 2023 revenue requirement reduction related to forecast customer deposits and Cal Advocates' position?

A 10 PG&E's adjustment equals the projected customer deposit balance for 2023 multiplied by a projection of the difference between the interest rate PG&E expects to pay in 2023 on customer deposits (0.70 percent) and PG&E's

[19] Exhibit (PG&E-10) (Feb. 28, 2022), WP 17-177, lines 10-12.

embedded cost of long-term debt (4.17 percent).[20] Cal Advocates simply states: "PG&E requires new customers to provide refundable customer advances when PG&E provides services to the new customers. The electric distribution and gas distribution rate base is reduced by the average customer advance balance."[21]

Q 11 Do you agree with Cal Advocates' position? Please discuss.

A 11 No, PG&E does not support Cal Advocates' position on customer advances as it might be applied to customer deposits. In a data request response, Cal Advocates confirmed that customer advances and customer deposits are not the same thing.[22] For ratemaking purposes, PG&E treats customer deposits as a source of debt capital to finance PG&E's operations.[23] Pursuant to the Commission's decisions, and as shown above, PG&E's forecast level of customer deposits, with a projected interest rate equal to the commercial paper rate, is used to adjust PG&E's cost of debt in calculating the return on rate base included in the GRC revenue requirement.

Q 12 How does PG&E recommend the Comission resolve this issue?

A 12 PG&E recommends that the Commission implement PG&E's revenue requirement adjustment for customer deposits as described above.

2. Revenue Lag and Bank Lag

Q 13 What is the second policy position you are addressing?

A 13 The second issue I will address is Cal Advocates' position on bank lag and TURN's position on revenue lag. I have combined these two policy positions because the bank lag is a component of the revenue lag.

a. Bank Lag (Cal Advocates)

Q 14 What is the difference between PG&E's and Cal Advocates' positions on the bank lag?

---

[20] Exhibit (PG&E-10) (Feb. 28, 2022), 14-154, lines 15-20.

[21] CA-15, p. 29, lines 22-24.

[22] Cal Advocates' responses to PG&E's Data Requests PGE-CalAdvocates_003-Q03(c), and PGE-CalAdvocates_003-Q04, dated 6/29/22 in Appendix A, at the end of this exhibit.

[23] D.14-08-032, pp. 629-630; and pp. 720-721, Finding of Fact (FOF) 310. D.19-12-056, pp. 47-48; p. 52, FOF 38; p. 54, Conclusion of Law (COL) 27; and, p. 55, OP 6.

A 14 Based on recorded data from 2020, PG&E estimated the bank lag to be 0.58 days.[24] Cal Advocates argues that the projected bank lag for 2023 should be 0.13 days.[25]

Q 15 Do you agree with Cal Advocates' position? Please discuss.

A 15 No, PG&E does not support Cal Advocates' position on this issue. Cal Advocates argues that since PG&E anticipates that 77.2 percent of customer bills will be paid electronically in 2023, PG&E's bank lag estimate should be reduced by 77.2 percent.[26] Cal Advocates implicitly assumes that electronic payments have a zero lag. They don't. While an electronic payment may appear to be instantaneous from the customer's perspective, delays in the receipt of funds can and do occur depending on how the payment is processed. For example, PG&E's arrangement with payment processors typically results in the receipt of funds one business day following the customer's payment submission.

Unfortunately, Cal Advocates far overstates any reasonable reduction in PG&E's bank lag for 2023. In the same data request response that provided the 77.2 percent projection of electronic payments for 2023,[27] PG&E provided corresponding actual data for the first half of 2021, 75.9 percent.[28] For the recorded year of 2020, the percentage of electronic payments was 61 percent.[29] So, the 0.58 bank lag for 2020 already reflects a high percentage of electronic payments. Between 2020 and PG&E's projection for 2023, electronic payments are projected to increase by about 16 percent, not 77.2 percent. Based on the data in PG&E's workpapers for 2020, the bank lag for electronic payments is 0.44 days, not zero.[30] So, any reduction in the revenue lag from changing the percentage of electronic

---

24 Exhibit (PG&E-10) (Feb. 28, 2022), WP 14-140, line 21.

25 CA-15, p. 34, lines 9-11.

26 CA-15, p. 34, lines 4-7.

27 PG&E's response to Data Request CalAdvocates_015-Q12(e), dated 8/20/21 in Appendix A, at the end of this exhibit.

28 PG&E's response to Data Request CalAdvocates_015-Q12(c), dated 8/20/21 in Appendix A, at the end of this exhibit.

29 Exhibit (PG&E-23), WP 14-5, line 22.

30 Exhibit (PG&E-23), WP 14-5, line 23.

payments would be small, about 0.6 days.[31] But that assumes 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.[32] Thus, PG&E's revenue lag estimate is reasonable.

Q 16 How does PG&E recommend the Commission resolve this issue?

A 16 PG&E recommends that the Commission deny Public Advocates' request to reduce the bank lag.

b. Revenue Lag (TURN)

Q 17 What is the difference between PG&E's position on the revenue lag and TURN's position?

A 17 PG&E estimates a revenue lag of 48.66 days.[33] In contrast, TURN argues for a revenue lag of 46.92 days.[34]

Q 18 Do you agree with TURN's position? Please discuss.

A 18 No, PG&E does not support TURN's position on this issue. First and most important, TURN ignores the data indicating that the revenue lag based on 2020 data is not abnormally high. PG&E's workpapers calculate the revenue lag for the years 2016 through 2019, prior to the Covid pandemic.[35] The average revenue lag for those four years is 48.82 days, which is higher than PG&E's 48.66 number in its direct testimony.[36]

Second, although TURN attempts make much of arrearage data, it is not the end-of-year arrearage data that matter for the revenue lag calculation, but the average year values. For 2019, average residential arrearages were $230.0 million; for 2020, average residential arrearages were $353 million.[37] As a percentage of net daily average outstanding revenues, these amounts were 10.2 percent in 2019 and 15.8 percent in 2020. While

---

31 Exhibit (PG&E-23), WP 14-2, line 6.

32 Exhibit (PG&E-10) (Feb. 28, 2022), WP 14-134, line 17.

33 Exhibit (PG&E-10) (Feb. 28, 2022), p. 14-18, Table 14-3, line 31 to p. 14-21, line 31.

34 TURN-19E, p. 9, lines 3-5.

35 Exhibit (PG&E-10) (Feb. 28, 2022), WP 14-134, line 19.

36 Exhibit (PG&E-10) (Feb. 28, 2022), p. 14-18, Table 14-3, line 31 to p. 14-21, line 31.

37 TURN-19E, p. 8, Table 2.

there is a noticeable increase in these percentages between 2019 and 2020, they are not the only factor affecting the revenue lag calculation. Indeed, inconveniently for TURN's logic, the revenue lag in 2019 was 52.03 days, higher than the revenue lag of 48.66 days for 2020 that TURN claims is abnormal.

Third, TURN's proposal to base the 2023 GRC revenue lag forecast as an average of *forecasts* from the 2017 GRC and the 2020 GRC means that the 2020 GRC revenue lag forecast would be based on some seriously old data, as the 2020 GRC forecast is the recorded revenue lag for 2017[38] and the 2017 GRC forecast is the recorded revenue lag for 2014.[39]

Q 19 TURN claims that the reduction in working cash from its revenue lag recommendation is $124.278 million. Is TURN's calculation correct?

A 19 No. Keeping in mind that PG&E does not agree with TURN's revenue lag recommendation, even if PG&E did agree with TURN on this issue, TURN's estimated working cash reduction would be incorrect. TURN has the wrong level of average daily expenses for Gas Distribution in Column D of Table 4.[40] Instead of $17.546 million, it should be $7.546 million. TURN should have calculated the working cash reduction from its revenue lag recommendation as $83.122 million.[41]

Q 20 How does PG&E recommend the Commission resolve TURN's revenue lag recommendation?

A 20 PG&E recommends that the Commission deny TURN's request to reduce the revenue lag.

c. Revenue Lag (Combined)

Q 21 How does PG&E recommend the Comission set the forecast level of revenue lag in this case?

---

38 A.18-12-009, HE-80: Exhibit (PG&E-10), p. 13-11, Table 13.2, line 31; p. 13-12, Table 13.3, line 31; and, p. 13-13, line 31. A.18-12-009, HE-89: Exhibit (PG&E-10), WP 13-104, line 15.

39 A.15-09-001, HE-PG&E-10: Exhibit (PG&E-10), p. 13-10, Table 13-2, line 31; p. 13-11, Table 13-3, line 31; and, p. 13-13, Table 13-5, line 31. A.15-09-001, HE-PG&E-10 WP 13-17, Exhibit (PG&E-10), WP 13-123, line 15.

40 TURN-19E, p. 10, Table 4, Col. D and Note (4).

41 Exhibit (PG&E-23), WP 14-3, line 5.

A 21 PG&E recommends that the Commission accept PG&E's recommended revenue lag of 48.66 days.

3. Goods and Services Expense Lag (TURN)

Q 22 What is the difference between PG&E's position on the goods and services expense lag and TURN's position?

A 22 Based on recorded data from 2020, PG&E estimated the goods and services expense lag to be 16.49 days.[42] TURN argues that the projected goods and services lag for 2023 should be 37.3 days.[43]

Q 23 Do you agree with TURN's position? Please discuss.

A 23 No, PG&E does not support TURN's position on this issue.

TURN's fundamental argument is that PG&E should be "optimizing cash flow by…lengthening the time to pay suppliers."[44] At its most basic level, this is an argument to treat suppliers poorly by making them bear the burden of working cash. TURN attempts to sanitize this argument by stating its proposal in clinical terms: "The higher the number of expense lag-days, the higher the amount of vendor-provided working cash and the lower the amount of working cash required from ratepayers."

Although TURN's statement is technically correct, there are two principal problems with it. The first is TURN's reference to "vendor-supplied working cash." 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. Second, PG&E will pay vendors sooner in cases where PG&E can obtain a discount from the vendor or other favorable terms. In fact, PG&E's payment portal 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 is completely silent on these aspects of the goods and services payment lag.

---

[42] Exhibit (PG&E-10) (Feb. 28, 2022), p. 14-18, Table 14-3, line 24 to p. 14-21, line 24.

[43] TURN-19E, p. 15, lines 3-5.

[44] TURN-19E, p. 10, lines 7-8.

TURN attempts to support its goods and services expense lag analysis by appealing to studies produced by PwC UK (United Kingdom). TURN also refers to a study published by JP Morgan.[45] Common to all three studies is most of their authors are based outside the United States; of 11 authors listed across the three studies, only 2 are based In the United States.[46] These studies are also silent on the impact of payment practices on vendors and the benefits that might be realized by different payment terms. The PwC studies are also dominated by companies outside of the United States and by companies that are not regulated utilities. In the more detailed PwC study, for 2019-20 (primarily based on data from 2017 and 2018), 13.4 percent of the companies were located in the United States and Canada.[47] Similarly, the PwC study for 2019-20 only classified 3.8 percent of the companies as utilities.[48] We don't know how many of these utilities are regulated utilities. The JP Morgan study appears to be based on over 900 firms selected from the S&P Composite 1500 index.[49] JP Morgan excluded financial services and real estate firms and companies with "high volatility in working capital and … incomplete data … ."[50] According to Standard & Poor's, utilities comprise only 3.1 percent of the S&P Composite

---

45 TURN-19E, p. 12, fns. 29-31.

46 TURN's responses to PG&E Data Requests PGE-TURN_011-Q05, -Q06 and -Q07, dated 6/30/22 in Appendix A, at the end of this exhibit.

47 PwC, Working Capital Report 2019/20: Creating value through working capital (2019), p. 16, in Attachment A at the end of this chapter.

48 PwC, Working Capital Report 2019/20: Creating valuethrough working capital (2019), p. 13, in Attachment A at the end of this chapter.

49 J.P. Morgan, J.P. Morgan Working Capital Index 2021, <https://www.jpmorgan.com/content/dam/jpm/treasury-services/documents/jpmc-working-capital-index-2021.pdf> (as of July 6, 2022), p. 3, in Attachment C at the end of this chapter.

50 J.P. Morgan, J.P. Morgan Working Capital Index 2021, <https://www.jpmorgan.com/content/dam/jpm/treasury-services/documents/jpmc-working-capital-index-2021.pdf> (as of July 6, 2022), p. 3, in Attachment C at the end of this chapter.

1500 Index.[51] Even if all of the utilities remained after JP Morgan's exclusions, utilities would be only a small share of the overall study.

Equally important, we don't know much about how the studies were performed. Asked in a data request for an explanation of how each of the three reports calculates Days Payable Outstanding for a utility, TURN could only respond that "TURN did not review or audit the formulas or data underlying PWC's calculations"[52] and "TURN did not attempt to evaluate or audit the detailed formulas or data underlying JP Morgan's calculations."[53] To summarize, the usefulness of these studies to provide guidance to the Commission is severely limited and the Commission should not rely on them.

Q 24 How does PG&E recommend the Commission resolve this issue?

A 24 PG&E recommends that the Commission accept PG&E's goods and services expense lag of 16.49 days.

4. Federal and State Income Tax Expense Lags (Cal Advocates, TURN)

Q 25 What are the differences between PG&E's position on federal and state income tax expense lags and Cal Advocates' and TURN's positions on these issues?

A 25 Based on the analyses presented in Exhibit (PG&E-10), Chapter 14,[54] regarding these issues, PG&E proposes that the federal and state income tax expense lags be set equal to the revenue lag of 48.66 days.

Q 26 What is Cal Advocates' position on this issue?

A 26 Cal Advocates recommends a federal income tax expense lag of 90 days. Cal Advocates' position on the state income tax expense lag is unclear. At first, it appears that Cal Advocates recommends a state income tax expense

---

51 S&P Dow Jones Indices, S&P Composite 1500® (June 30, 2022), "Sector* Breakdown," <https://www.spglobal.com/spdji/en/idsenhancedfactsheet/file.pdf?calcFrequency=M&force_download=true&hostIdentifier=48190c8c-42c4-46af-8d1a-0cd5db894797&indexId=1636> (as of July 6, 2022), p. 5.

52 TURN's responses to PG&E Data Requests PGE-TURN_011-Q05 and PGE-TURN_011-Q06, dated 6/30/22 in Appendix A, at the end of this exhibit.

53 TURN's response to PG&E's Data Request PGE-TURN_011-Q07, dated 6/30/22 in Appendix A, at the end of this exhibit.

54 Exhibit (PG&E-10) (Feb. 28, 2022), p. 14-9, line 3 to p. 14-14, line 29.

lag of 90 days.[55] However, Cal Advocates refers to "PG&E's initial forecast."[56] While PG&E's initial proposal for the federal income tax expense lag was 90 days, PG&E's initial proposal for the state income tax expense lag was only 75.90 days.[57]

Q 27 Do you agree with Cal Advocates' position? Please discuss.

A 27 No, PG&E does not support Cal Advocates' position on this issue. With respect to the state income tax expense lag, PG&E does not support 90 days nor 75.90 days.

PG&E explained in a data response to Cal Advocates that its original calculation of a 90-day federal income tax expense lag was superseded by testimony served on August 27, 2021.[58] This is also true with respect to PG&E's original calculation of a state income tax expense lag of 75.90 days.

PG&E does not anticipate paying cash income taxes in the test year 2023 because of continuing Net Operating Losses (NOLs) that do not yield a cash benefit until the time they are applied to offset income tax owed.[59] Where these NOLs arise from "bonus" or accelerated depreciation, deferred taxes are created and the resulting tax benefits are provided to ratepayers as a reduction to rate base.[60] Where these NOLs belong to shareholders, generally as a result of shareholder payment of claims to wildfire victims, they should not affect the working cash calculation. Setting the corresponding expense lag equal to the revenue lag is the correct way to ensure this outcome.[61] To do otherwise is to assume that current taxes collected in rates are available to fund rate base, when in fact that cash will largely be used to pay off the debt raised in 2020 to pay a portion of claims to wildfire victims. That debt will be paid off through funding of the Customer Credit Trust, as discussed more later.

---

55 CA-15, p. 33, lines 13-23.

56 CA-15, p. 33, line 22.

57 Exhibit (PG&E-10) (6/30/21), p. 14-13, Table 14-3 (see line 9) to p. 14-16, line 9.

58 PG&E's response to Data Request CalAdvocates_068-Q08 and Q09, dated 9/28/21 in Appendix A, at the end of this exhibit.

59 Exhibit (PG&E-10) (Feb. 28, 2022), p. 14-11, lines 13-28.

60 Exhibit (PG&E-10) (Feb. 28, 2022), p. 14-10, line 1 to p. 14-11, line 12.

61 Exhibit (PG&E-10) (Feb. 28, 2022), p. 14-11, line 13 to p. 14-12, line 17.

For the reasons explained above, it is logical for PG&E to set the federal and state income tax expense lags equal to the estimated revenue lag, as doing so eliminates any impact on the working cash calculation from shareholder NOLs.

Q 28 Cal Advocates claims that “PG&E is violating the ‘rate-neutral’ approach that the Commission ordered PG&E to follow … .”[62] How do you respond to this claim?

A 28 Asked in a data request to provide workpapers and supporting documents associated with the text cited in this question, Cal Advocates provided none.[63] In the same data response, Cal Advocates did provide several citations to D.21-04-030.[64] Without exception, these citations address rate neutrality solely in the context of the features of the rate-neutral securitization and do not reference the General Rate Case (GRC) in any way.

In D.20-05-053, the Commission wrote the following regarding 2017 and 2018 wildfire claims:

> PG&E may not seek cost recovery for [2017 and 2018] wildfire claims except in connection with the proposed nominally offset securitization described in the documents attached to PG&E’s March 24, 2020 motion for official notice, and therefore those costs are not a factor in determining if the plan is neutral, on average, to ratepayers.[65]

Regarding the securitization, as explained in PG&E’s direct testimony, consistent with the requirements of Decisions 21-04-030 and 21-05-015, PG&E will issue rate-neutral securitized debt serviced by non-bypassable customer charges. Subsequently, as the tax benefits of the NOLs that belong to shareholders are realized, PG&E will contribute the cash to a Customer Credit Trust to provide a credit to customers.[66] PG&E has begun contributing funds to the Customer Credit Trust and it has begun providing

62 CA-15, p. 33, lines 17-18.

63 Cal Advocates’ response to PG&E’s Data Request PGE-CalAdvocates_003-Q09(a), dated 6/29/22 in Appendix A, at the end of this exhibit.

64 Cal Advocates’ response to PG&E’s Data Request PGE-CalAdvocates_003-Q09(b), dated 6/29/22 in Appendix A, at the end of this exhibit.

65 D.20-05-053, p. 82.

66 Exhibit (PG&E-10) (Feb. 28, 2022), p. 14-12, lines 18-23.

credits to customers. It is this interplay that makes the securitization rate neutral.

PG&E's proposed federal and state income tax expense lags do *not* and should not affect the recovery bonds that will be issued in the securitization or the fixed recovery charges related to those bonds. Likewise, the expense lags do not recover wildfire claim costs. In addition, the expense lags would not be different if the securitization had never been proposed or never happened since the securitization per se does not affect the form of the NOLs. Absent the securitization, the NOLs related to payment of claims to wildfire victims would still be used to pay off the debt raised in 2020 to pay a portion of those claims. Cal Advocates' claim that PG&E's proposal regarding these expense lags somehow violates rate neutrality associated with the bankruptcy reorganization or the securitization of wildfire costs is incorrect. Rather, it is important to maintain separation between the rate-neutral securitization, the payment of claims to wildfire victims, and the GRC to avoid any cross-over impacts.

Thus, setting the federal and state income tax expense lags to be longer than the revenue lag effectively assumes the taxes collected in rates are available to fund rate base, thus inappropriately reduce PG&E's authorized working cash amount. Doing so would ignore pertinent facts and the Commission's findings in OII 24 that have governed Commission policy in this area for many years, and would ignore the requirements of rate neutral securitization. Modifying the federal income tax expense lag to provide additional benefits to ratepayers is not warranted.

OII 24 clearly established the principle that factors outside of the GRC should not be considered in deriving the income tax amounts included in the GRC revenue requirement.[67] The Commission determined that expenses reducing tax obligations, such as shareholder payment of claims to wildfire victims, that are not allowed for ratemaking should not be used to benefit ratepayers.[68] The Commission concluded that if these tax benefits were allocated to ratepayers, shareholders would suffer an unjustified loss of net

---

[67] D.84-05-036, pp. 16-17.

[68] D.84-05-036, p. 16.

income equal to the full amount of the disallowed tax deduction, while ratepayers would receive an unjustified windfall arising from rates based on tax benefits that did not belong to them.[69] Losses realized outside the GRC should not be used to provide a benefit to customers in establishing the GRC revenue requirement. Setting PG&E's federal and state income tax expense lags greater than the revenue lag, however, would provide just such a benefit to customers by incorrectly reducing PG&E's allowed level of working cash because of the impact of shareholder NOLs on PG&E's federal and state income tax payments. As shown in PG&E's direct testimony and in the testimony above, setting the federal and state income tax expense lags equal to the revenue lag of 48.66 days avoids an incorrect outcome.

Q 29 Cal Advocates estimates that changing the income tax expense lags to 48.66 days results in an increase in working cash requirement of $124.09 million.[70] Do you agree with this calculation?

A 29 No, I do not. The $124.09 calculation is simply the difference between what Cal Advocates claims is PG&E's initial estimate of working cash, $934 million, and PG&E's current estimate of working cash, $1.058 billion.[71] Asked for workpapers and supporting documents related to this calculation, Cal Advocates simply pointed back to the testimony.[72] While Cal Advocates is correct on the total working cash amounts provided in PG&E's original testimony and PG&E's updated testimony, there were errata changes included in PG&E's February 28, 2022 testimony,[73] therefore it is not correct to use the difference in total working cash to estimate the impact of correcting the income tax expense lags. The correct working cash change is approximately $76.6 million.[74]

---

69 D.84-05-036, pp. 16-17; also see p. 49, Findings of Fact (FOF) 14 and 15.

70 CA-15, p. 32, lines 21-22.

71 CA-15, p. 32, fn. 87.

72 Cal Advocates' response to PG&E's Data Request PGE-CalAdvocates_003-Q08, dated 6/29/22 in Appendix A, at the end of this exhibit.

73 Exhibit (PG&E-10) (Feb. 28, 2022), Ch. 14.

74 Exhibit (PG&E-23), WP 14-4, line 36.

Q 30 What is TURN's position on the issue of the federal and state income tax expense lags?

A 30 TURN recommends much longer federal and state income tax expense lags than Cal Advocates: 292 days for the federal income tax expense lag and 365 days for the state income tax expense lag.[75]

Q 31 Do you agree with TURN's position? Please discuss.

A 31 No. TURN's position is flawed because TURN has effectively confused cash accounting and accrual accounting. As a result, TURN's calculations of the income tax expense lags are baseless.

TURN's mistake is easily seen in the headings in Tables 6 and 7 in TURN's testimony.[76] Column E in both tables is titled "Authorized Taxes Due per Day in $000."[77] This is not correct when considering cash payments; PG&E does *not* remit income taxes to the federal and state governments on a daily basis. When corporations such as PG&E pay estimated income taxes, they do it on a quarterly basis, not a daily basis.[78] As a result, one of the basic assumptions of TURN's tax expense lag calculation is incorrect.

What TURN is really doing is calculating the percentage of annual tax expense that was paid during that year and then multiplying that percentage by 365, the number of days in the year, to calculate its estimate of the income tax expense lag. That is easily seen in TURN's Tables 6 and 7: divide the entry in Column D by the entry in column B, multiply by 365 and the result will be the entry in Column F.[79] But then suppose for a hypothetical year that the total annual tax expense was paid during the year, so that the entry in Column D is zero (no remaining taxes unpaid). TURN's

---

75 TURN-19E, p. 20, lines 3-4.

76 TURN-19E, pp. 18-19.

77 TURN-19E, pp. 18-19.

78 For both federal and California corporate income taxes, estimated tax payments are due on the 15th day of April, June, September, and December for corporations using the calendar year as their tax year, with some adjustments for weekends and holidays. See, Internal Revenue Service Publication 509, <https://www.irs.gov/pub/irs-pdf/p509.pdf>; and, California Franchise Tax Board, 2022 Corporation Estimated Tax, Form 100-ES, <https://www.ftb.ca.gov/forms/2022/2022-100-es.pdf > (as of July 6, 2022).

79 TURN-19E, pp. 18-19.

method would result in an expense lag of zero. But that is clearly *not* the right answer because PG&E does not remit income taxes on a daily basis.

TURN makes the same mistake in footnote 64 in its testimony on working cash[80] and in its workpaper associated with that footnote.[81] In the workpaper, divide the entry in Column D by the entry in column B, multiply by 365 and the result will be the entry in Column F. Because TURN assumes that 20 percent of the tax is paid in the test year, the payment lag equals 80 percent of a full year. It is easy to see again that if all the tax was paid in the test year, the payment lag would be zero by TURN's method, which would be incorrect.

Q 32 In TURN's testimony at p. 17, TURN compares PG&E's tax expense with actual cash tax payments.[82] How do you respond to this discussion?

A 32 TURN is essentially asking the question: if cash tax payments are less than authorized tax expense, what happens to the difference? The answer is that while it is not possible to trace individual dollars to their ultimate destination using PG&E's financial statements, those statements show that the cash flows related to federal and state income taxes were a prime source for funding PG&E's capital expenditures during this period; those capital expenditures are embedded in capital assets that serve PG&E customers today and in the future. The mechanism that achieves this result is deferred income taxes that is a reduction to rate base, as discussed in PG&E's direct testimony.[83]

Each year, PG&E files Form 10-K with the Securities and Exchange Commission, an annual report for the prior year. Form 10-K includes a statement of cash flows that shows at a high level, sources and uses of cash within PG&E. Data from the Consolidated Statements of Cash Flows show that income tax-related cash flows financed capital expenditures, allowing PG&E to maintain and expand its capital assets to serve customers.

---

80 TURN-19E, p. 20, fn. 64.

81 TURN-19, WP, Tab Tax Lag Day Cals, "PG&E Estimated Federal Income Tax Lag Days Based on 20% NOL Exclusion and No Tax Credits" (Worksheet Rows 59-74).

82 TURN-19E, p. 17, lines 7-11.

83 Exhibit (PG&E-10) (Feb. 28, 2022), p. 14-12, line 27 to p. 14-13, line 13.

Table 14-1 below shows excerpted data from PG&E's Consolidated Statements of Cash Flows included in annual Form 10-K reports filed with the United States Securities and Exchange Commission.

In Table 14-1, lines 1 through 12 show selected cash flow items from the Statements that are related to financing capital expenditures.[84] Net income (earned "return on capital") in line 2 is cash from operations after payment of expenses that is available to shareholders as dividends or for reinvestment in capital equipment to serve customers.

Line 13 is the calculated amount of net income that is retained each year for that reinvestment. Other sources of cash for reinvestment are depreciation, amortization, and decommissioning (line 3, repeated as line 15; can be thought of as "return of capital") and the net amount of current and deferred taxes (line 14, which is the sum of lines 4 and 5).

Line 6 is the total net cash provided by operating activities. Adjusting this amount by lines 10 and 11 calculates net cash provided by operating activities after dividends have been paid to preferred and common stock shareholders. That adjusted amount is shown in line 16.

Line 16 provides a base on which to assess the relative importance of reinvested net income, net cash flows related to deferred taxes, and cash flows from depreciation and related items, in financing PG&E's capital expenditures. Years 2018 through 2020 were not normal years for this assessment because of wildfire-related losses and PG&E's financial reorganization in bankruptcy.

In years 2011 through 2017, and 2021, depreciation, amortization, and decommissioning were the largest share of cash provided by operating activities. But the second largest share, and in some years a significant multiple of retained net income, was cash from deferred and current taxes. Far from being idle cash benefitting PG&E's shareholders in some way, the cash flow from federal and state income tax expense collected in rates since 2011 was invested in capital assets to serve PG&E's customers.

---

84 There are other line items in the Statements, but they are not pertinent to the discussion here.

Q 33 At the end of its discussion of the SCE case, TURN suggests that OII 24 can be disregarded in extraordinary situations and alludes to the Air California-Westgate "situation."[85] How do you respond to this discussion?

A 33 The facts of the Air California-Westgate case are quite different from PG&E's current and projected situation.[86] Westgate-California Corporation entered bankruptcy in 1974, but failed to reorganize successfully, and was liquidated in 1982. A liquidation[87] may be an extraordinary situation contemplated in OII 24, since a liquidated entity no longer exists as a tax-paying entity. TURN's testimony presumes a situation that is not remotely similar to PG&E at present.

Q 34 How does PG&E recommend the Commission resolve this issue?

A 34 PG&E recommends that the Commission accept PG&E's federal and state income tax expense lags of 48.60 days.

Q 35 Does this conclude your rebuttal testimony?

A 35 Yes, it does.

---

85 TURN-19E, p. 16, line 20, to p. 17, line 2.

86 Air California was controlled by Westgate-California Corporation, which also controlled a baseball team, a tuna cannery, real estate holdings, and taxicab franchises. AP, Final Chapter Written in Saga of Westgate, New York Times (May 6, 1982), <https://www.nytimes.com/1982/05/06/business/final-chapter-written-in-saga-of-westgate.html%20as%20of%20June%2029> (as of July 6, 2022).

87 Bankruptcy and subsequent liquidation is very different from bankruptcy and reorganization. In the former situation, the bankrupt corporation ceases to exist, while in the latter, the bankrupt corporation is reestablished as a going concern.

TABLE 14-1
PACIFIC GAS AND ELECTRIC COMPANY
EXCERPTED DATA FROM CONSOLIDATED STATEMENTS OF CASH FLOWS
(MILLIONS OF DOLLARS)

Line No.		2011	2012	2013	2014	2015	2016	2017	2018	2019	2020	2021
1	**Cash Flows from Operating Activities**											
2	Net income (loss)	845	811	866	1433	862	1402	1691	(6818)	(7622)	411	138
3	Depreciation, amortization, and decommissioning	2215	2272	2077	2432	2611	2754	2854	3036	3233	3469	3403
4	Deferred income taxes and tax credits, net	582	684	1103	731	714	1042	1103	(2548)	(2952)	1141	1846
5	Income taxes receivable/payable	(192)	(50)	(377)	395	38	(29)	159	(5)	5	0	0
6	Net cash provided by operating activities	3763	4928	3416	3632	3747	4344	5916	4704	4810	(19047)	2448
7	**Cash Flows from Investing Activities**											
8	Capital expenditures	(4038)	(4624)	(5207)	(4833)	(5173)	(5709)	(5641)	(6514)	(6313)	(7690)	(7689)
9	**Cash Flows from Financing Activities**											
10	Preferred stock dividends paid	(14)	(14)	(14)	(14)	(14)	(14)	(14)	0	0	0	0
11	Common stock dividends paid	(716)	(716)	(716)	(716)	(716)	(911)	(784)	0	0	0	0
12	Net cash provided by financing activities	349	(424)	1597	1157	1468	1194	110	2708	1395	26070	4379
13	Net income less dividends	115	81	136	703	132	477	893	(6818)	(7622)	411	138
14	Net of deferred and current taxes	390	634	726	1126	752	1013	1262	(2553)	(2947)	1141	1846
15	Depreciation, amortization, and decommissioning	2215	2272	2077	2432	2611	2754	2854	3036	3233	3469	3403
16	Net cash provided by operating activities after adjustment for dividends	3033	4198	2686	2902	3017	3419	5118	4704	4810	(19047)	2448
17	Net income less dividends, percentage of adjusted net cash provided by operating activities	3.79%	1.93%	5.06%	24.22%	4.38%	13.95%	17.45%	-144.94%	-158.46%	-2.16%	5.64%
18	Net of deferred and current taxes, percentage of adjusted net cash provided by operating activities	12.86%	15.10%	27.03%	38.80%	24.93%	29.63%	24.66%	-54.27%	-61.27%	-5.99%	75.41%
19	Depreciation, amortization, and decommissioning, percentage of adjusted net cash provided by operating activities	73.03%	54.12%	77.33%	83.80%	86.54%	80.55%	55.76%	64.54%	67.21%	-18.21%	139.01%

PACIFIC GAS AND ELECTRIC COMPANY

CHAPTER 14

ATTACHMENT A

PWC WORKING CAPITAL REPORT 2019/20

2019

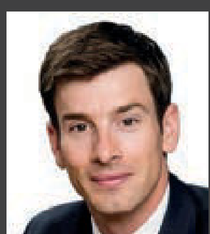
Working Capital Report 2019/20: Creating value through working capital

Unlocking cash in a digital age

pwc

Table of contents:

Daniel Windaus
Partner, PwC UK



Stephen Tebbett
Partner, PwC UK

Why it matters

Working capital is the cash tied up in the everyday running of a business

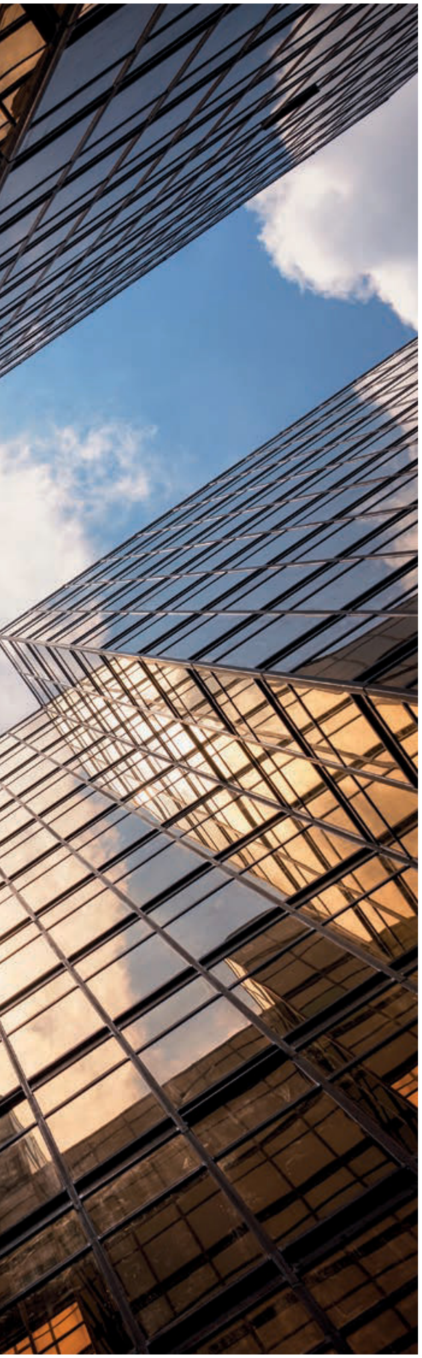
Each year, PwC UK review the financial performance of the largest global listed companies, assessing their working capital performance and related key indicators. In this year's report we have continued to review five-year trends (2014 – 2018) and reflected on the advent of digital and its potential for creating value through improved working capital management.

In the face of rapidly-changing business models and disruption, cash and working capital are fundamentals that businesses can easily lose sight of. Harnessing the power of digital presents a singular opportunity to take back control, addressing the challenges presented by organisational silos, complex systems and conflicting targets. Companies that are able to exploit digital's benefits will lead the way in unlocking cash and creating more value.

Digital enablers are now sufficiently accessible and flexible that they should be a standard tool for accelerating working capital improvement. Data analytics can be used to help achieve transparency in relation to cash performance and to better align the efforts of different commercial and operational functions. Furthermore, artificial intelligence (AI), specialist cloud-based solutions and robotic process automation (RPA) are becoming increasingly central to the optimisation of working capital.

Over the past five years, we have seen the gap between the higher and lower working capital performers stay relatively stable. More than half of the industry sectors have made some progress in addressing the working capital challenge, but not all. This indicates that there is still plenty of opportunity to create value through optimising working capital levels.

Source: PwC analysis. Analysis uses data available from 13,328 globally listed companies between January 2014 and June 2019



What's the story?

Looking at the financial performance of the largest global listed companies in the past five years, we have noticed five key trends:

1. **Working Capital is the next value driver**
   Improvements in returns have mostly come through EBIT. Some of the value created has, however, been offset by stalling net working capital (NWC) performance, restraining the improvement in return on invested capital (ROIC). Addressing excess working capital would lift overall ROIC by up to 30bps (basis points).

2. **Working Capital is finally improving**
   While net working capital increased by €360bn in 2018 (up 9.4% on 2017), relative performance in terms of days has improved marginally by 0.1 days.

3. **As predicted, Payables Days have been unsustainable**
   For the second successive year we have seen a decrease in Days Payable Outstanding (DPO), underlining that the use of DPO as a quick fix is not sustainable in the long term as a working capital management strategy.

4. **Receivables and Inventory are major sources of opportunity**
   Many companies have finally started to achieve significant improvements in both "days sales outstanding (DSO) and "days inventory outstanding" (DIO). This has been much needed in light of the downward pressure on DPO. DSO has shown its first improvement in five years as companies have begun to address the asset side of the balance sheet.

5. **The need for cash is increasing**
   While revenues are up 10% over, in 2017, in 2018 operating cash flows (OCF) have declined as a proportion of sales. Companies are facing operational challenges in converting revenue into cash. During the same period, capital expenditure (CAPEX), as a percentage of revenues has continued to decline, which could suggest that companies are managing cash levels by limiting investment.

€1.2tr
excess working capital tied up on global balance sheets

3.8%
decrease in Days Payables Outstanding

8/18
sectors have improved working capital

> **“ The asset side of the balance sheet is finally getting some much-needed attention and is moving closer in line with Payables days.**

The working capital profile

Globally, our research has revealed an absolute increase in net working capital (NWC) of €360bn in 2018 (up 9.4% on 2017). In relative terms, however, NWC days have improved for the first time in five years.

The increase in NWC was offset by a 9.6% increase in revenue from the previous year, resulting in a small decrease in NWC Days to 47.5. In our 2016 and 2017 working capital studies, we highlighted a trend of companies maintaining working capital performance at the expense of their suppliers, and noted that this approach would not be sustainable in the long term.

For the second successive year there has been a decrease in DPO, strongly suggesting that the continuing push on creditor days is not sustainable. This was compounded by increased government and regulatory pressure on prompt payment, especially in Europe. After performance plateaued in 2017, DPO has now started to decline more sharply, falling by four days compared to 2016 as companies ensure suppliers are paid earlier and the value chain is not squeezed. This is the most significant swing in the past five years in what has been historically the most popularly deployed working capital lever.

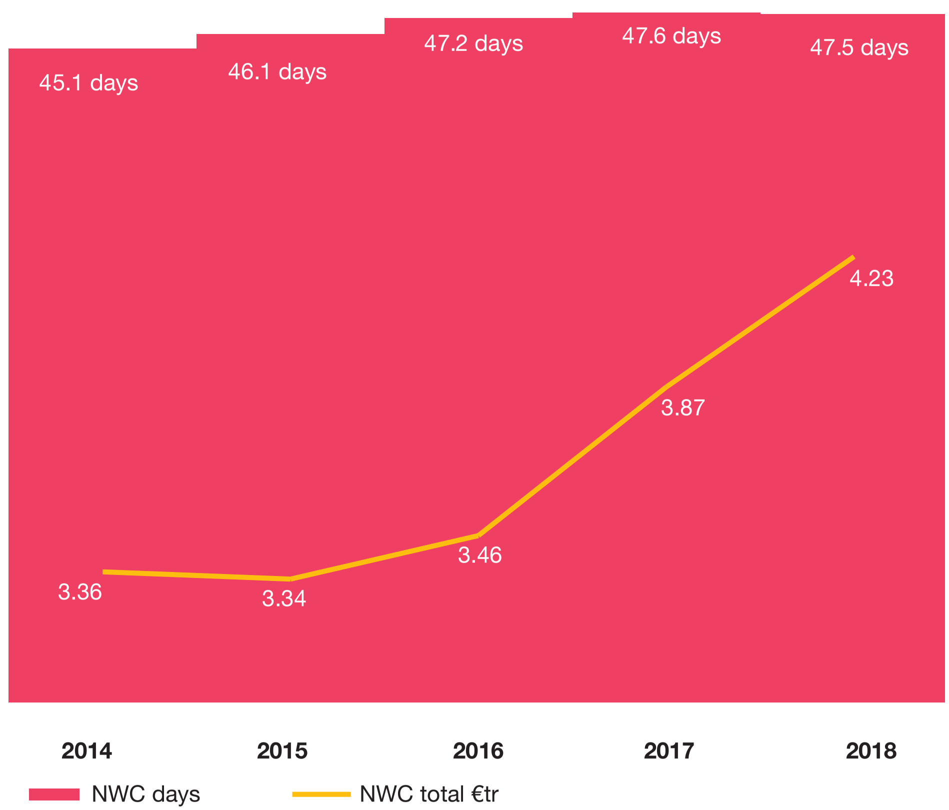
This readjustment of the Trade Payables position is placing pressure on some companies’ ability to improve performance in Trade Receivables and Inventory, which historically many companies have found difficult to achieve.

After years of deterioration in Receivables and Inventory performance, many companies have finally started to achieve significant improvements in both DSO and DIO. DSO has shown its first improvement in five years, reflecting more focused collections activity and cautious granting of payment terms ahead of anticipated market uncertainties. Inventory performance has continued to improve, a trend that started in 2017.

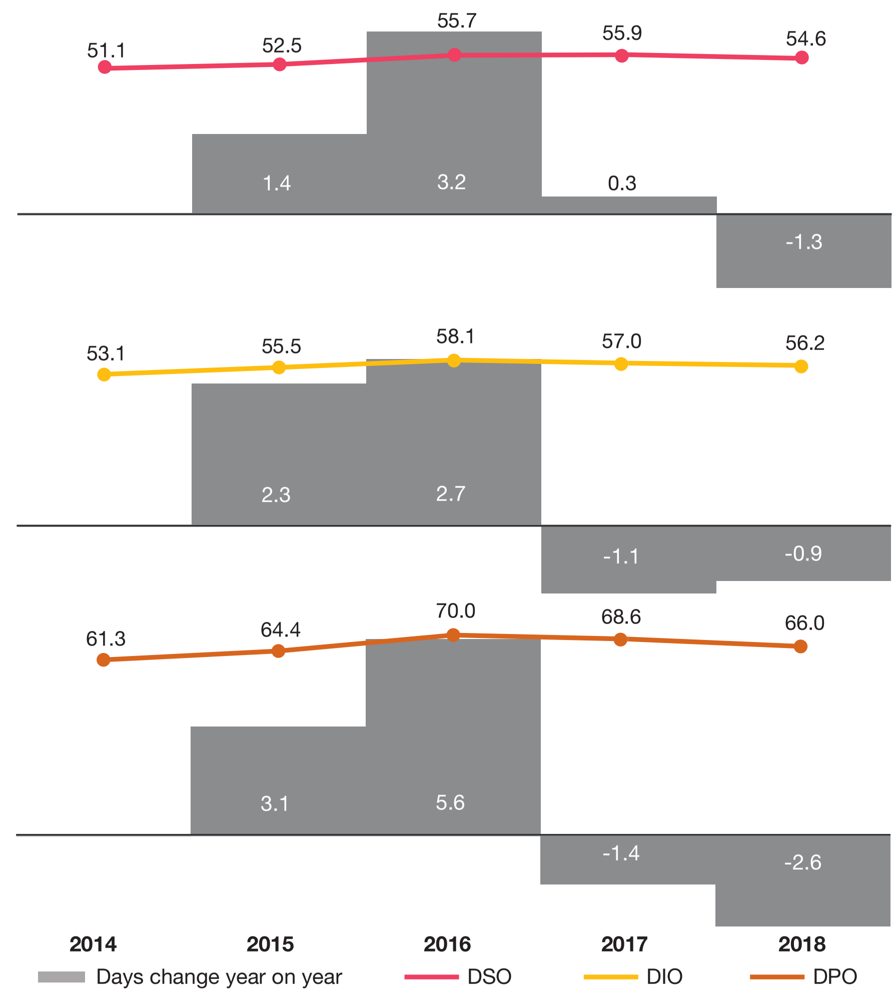
We assess that these developments suggest the asset side of the balance sheet is moving closer in line with Payables days, even if overall DPO is still 9 to 10 days longer than Inventory or Receivables days.

As we explore in the study, these trends are not the same across all companies and industries. A closer inspection reveals that the Industrial Manufacturing and Energy sectors were major contributors to revenue growth during the past year. When these two sectors are excluded, there was actually a global decline in NWC performance of 1.7 days.

Net working capital and working capital days



DSO, DIO and DPO trend

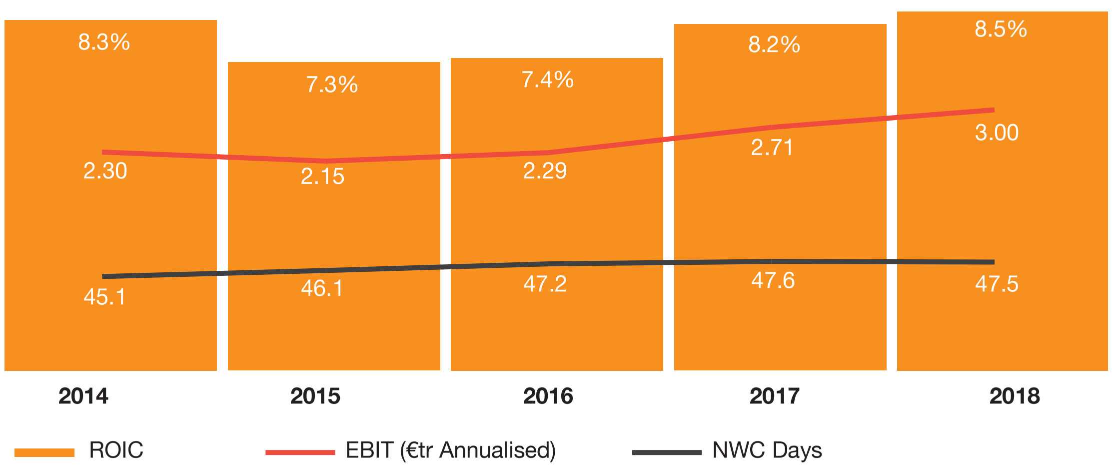


The next value creation lever

At a time of digital disruption and dramatic shifts in business models across industries, companies' ability to create value has never been more important.

Working capital presents a value creation opportunity not only in "business as usual" circumstances but also in a deals environment. Our analysis suggests that more can be done to boost ROIC through working capital management.

EBIT/ROIC trend



Capital-efficient, profitable growth underpins value creation — and while companies have managed to improve returns as measured by ROIC, they have mostly achieved this through closely managing EBIT. Some of the value created through EBIT growth has, however, been offset by stalling NWC performance, restraining the improvement in ROIC.

A singular focus on 'profitable growth' is still common, and ignores other value creation levers. Often, such a focus will include extending customer terms to 'buy' market share or increasing inventory ahead of forecasted ambitious growth. More often than not, the latter approach leads to overstocking and to an increase in slow-moving and obsolete stock.

Our recent report "Creating value beyond the deal" surveyed 600 senior corporate executives from a range of industries and geographies. In the research, 83% of sellers said there is room for improvement on extracting working capital. This suggests a need for companies to have a comprehensive value creation plan – a guideline, not a checklist, with working capital as a core component.

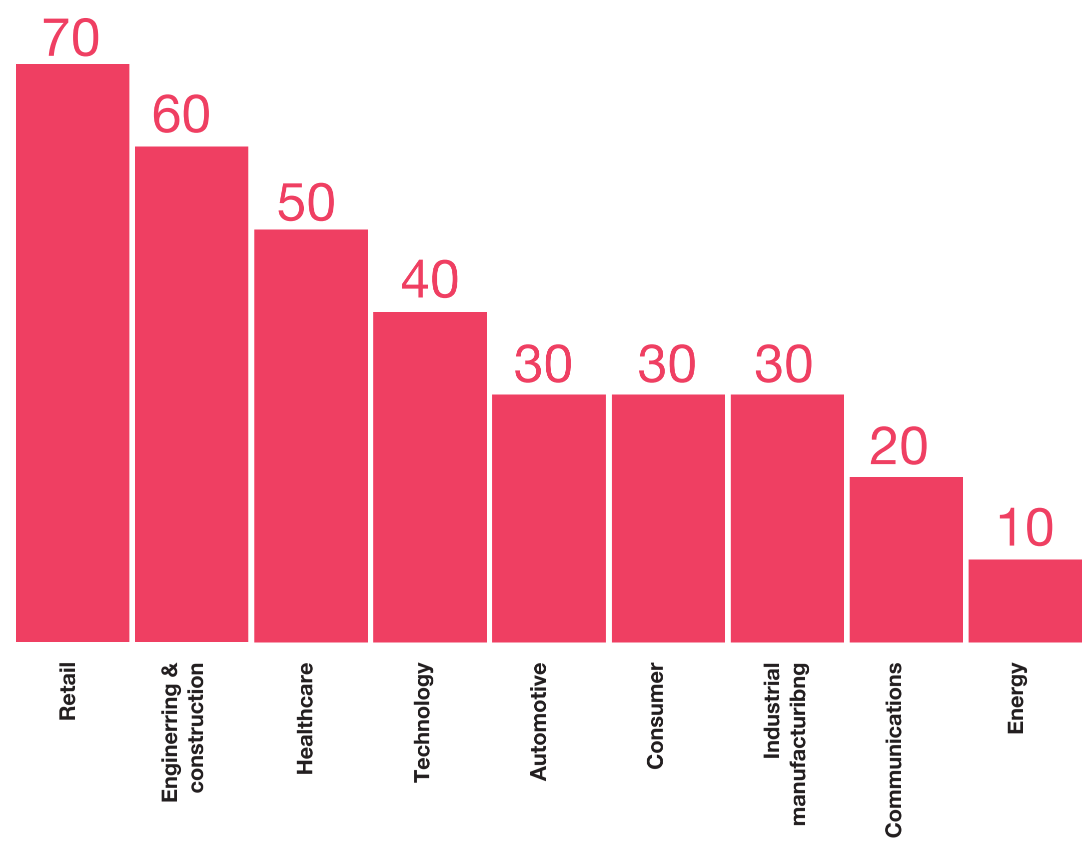
We further assess that the overall trend in returns could have been further improved by around 30 bps if companies were to address excess working capital. The most significant uplift would likely come from sectors that are already under pressure both in terms of revenues and working capital, such as Retail, Engineering and Automotive.

We judge that companies that are able to release more cash from working capital, would likely further improve their return on investment – particularly if revenue growth were to slow.

We believe the total global cash opportunity that companies could release through better working capital management is €1.2tr, which would lift overall ROIC to 8.8%.

Working capital therefore presents an attractive prize in both “business as usual” and deal situations — and should be high on the agenda for prospective buyers and sellers as they look to build a comprehensive value creation plan pre and post-deal.

BPS improvement in ROIC through eliminating excess Working Capital



Eight out of 18 sectors have improved working capital since 2017

Industry Performance

When we analyse how sector performance has evolved in the past year, we find large disparities – with only eight sectors out of 18 showing an improvement.

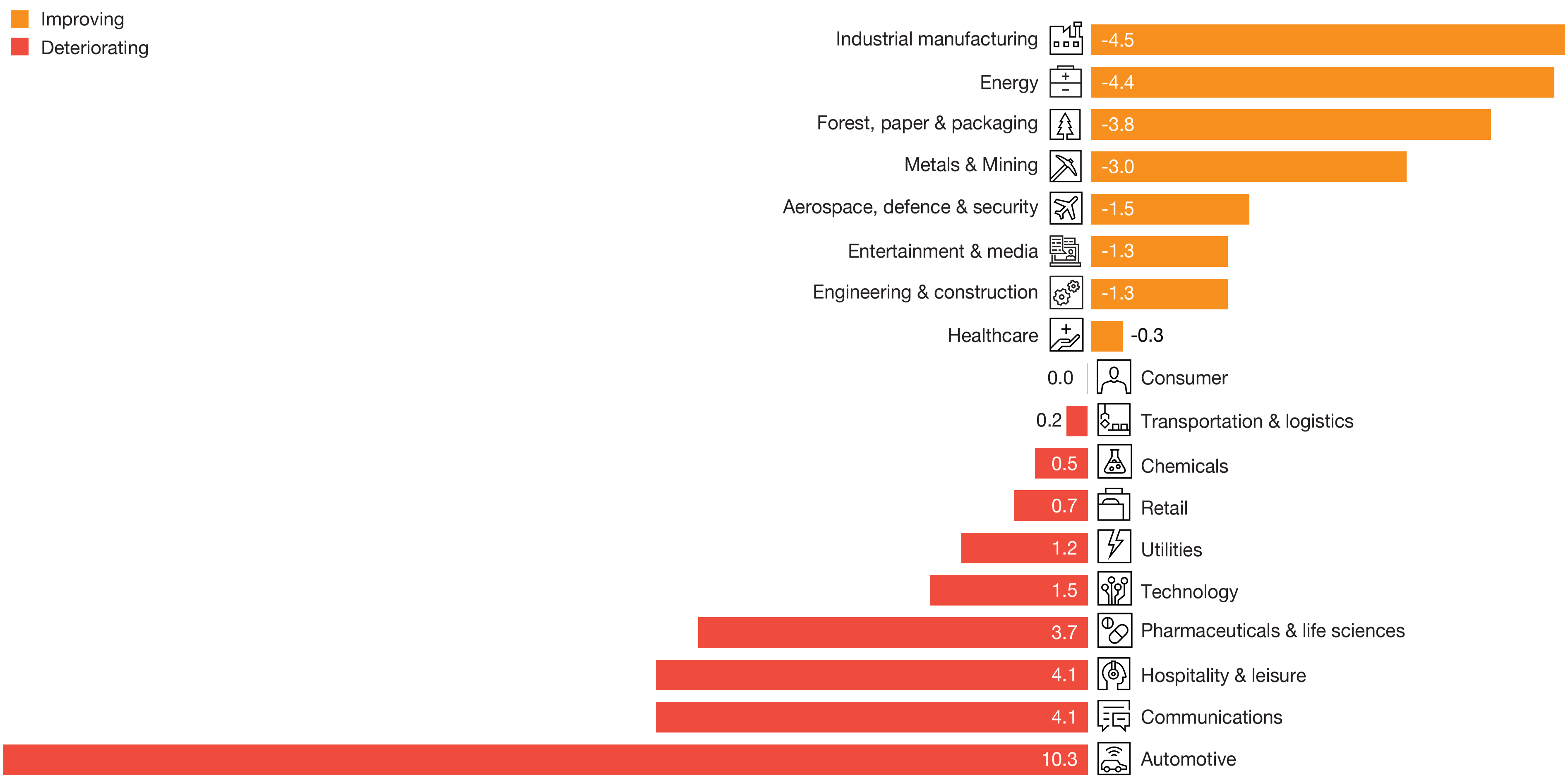
Industrial manufacturing saw an improvement of 4.5 days in NWCD in the past year, the largest reduction of any sector. This was driven by improvements on the asset side of the balance sheet, with significant decreases in both DSO (6 days) and DIO (2.9 days).

The Energy sector came a close second, with companies achieving a 4.4 day reduction in NWCD, driven by decreases in DSO (6.5 days) and DIO (5.5 days), offset by an 8.5-day reduction in DPO.

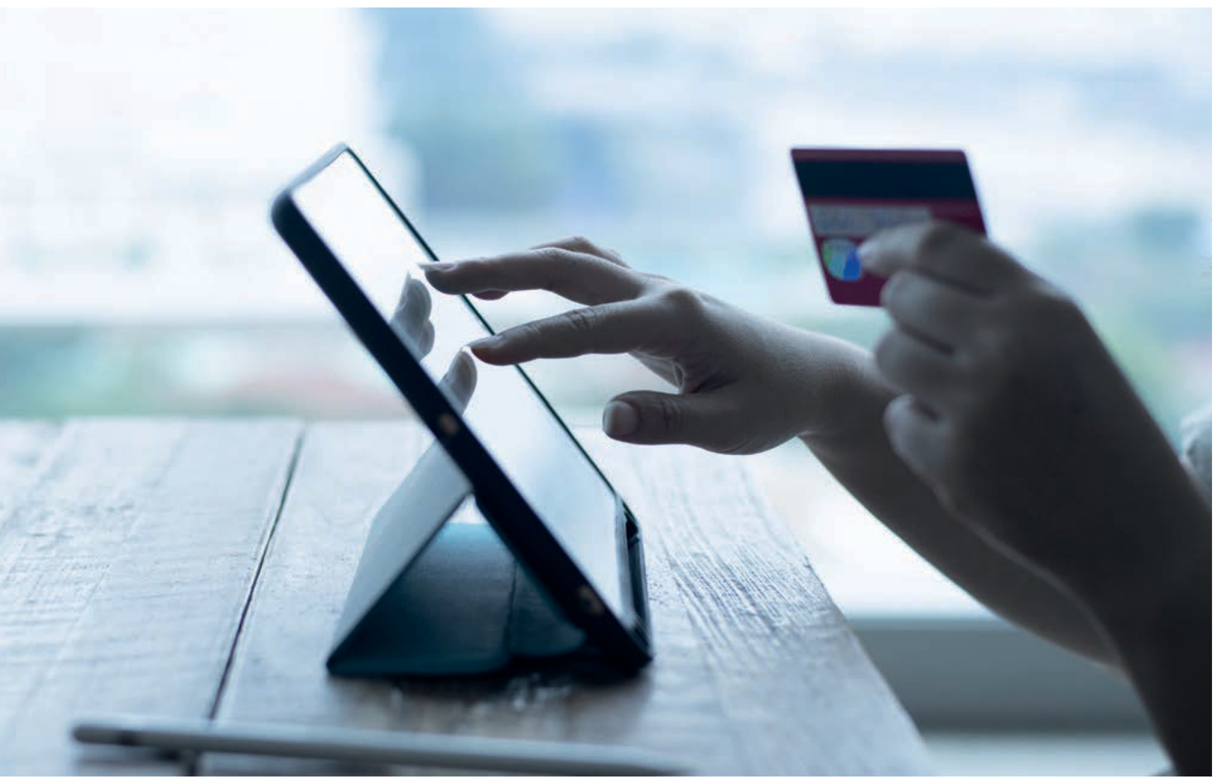
By contrast, the Automotive sector has experienced the largest deterioration in performance in the past year. This has been driven by an increase in DSO of 8 days. Global trade uncertainties are likely affecting DIO and the working capital impact that is expected.

Furthermore, while sector-level trends give us an indication of the challenges facing certain industries, performance also varies widely at a company level within each sector.

Working capital change 2017-2018 expressed in days



Some sectors are still lengthening payables to maintain Net Working Capital



The visualisation on page 11 shows the key levers that are driving changes in working capital performance at a sector level.

Sectors in orange have seen a reduction in net working capital days (NWCD) in the past year, while those in red have seen a decline in performance.

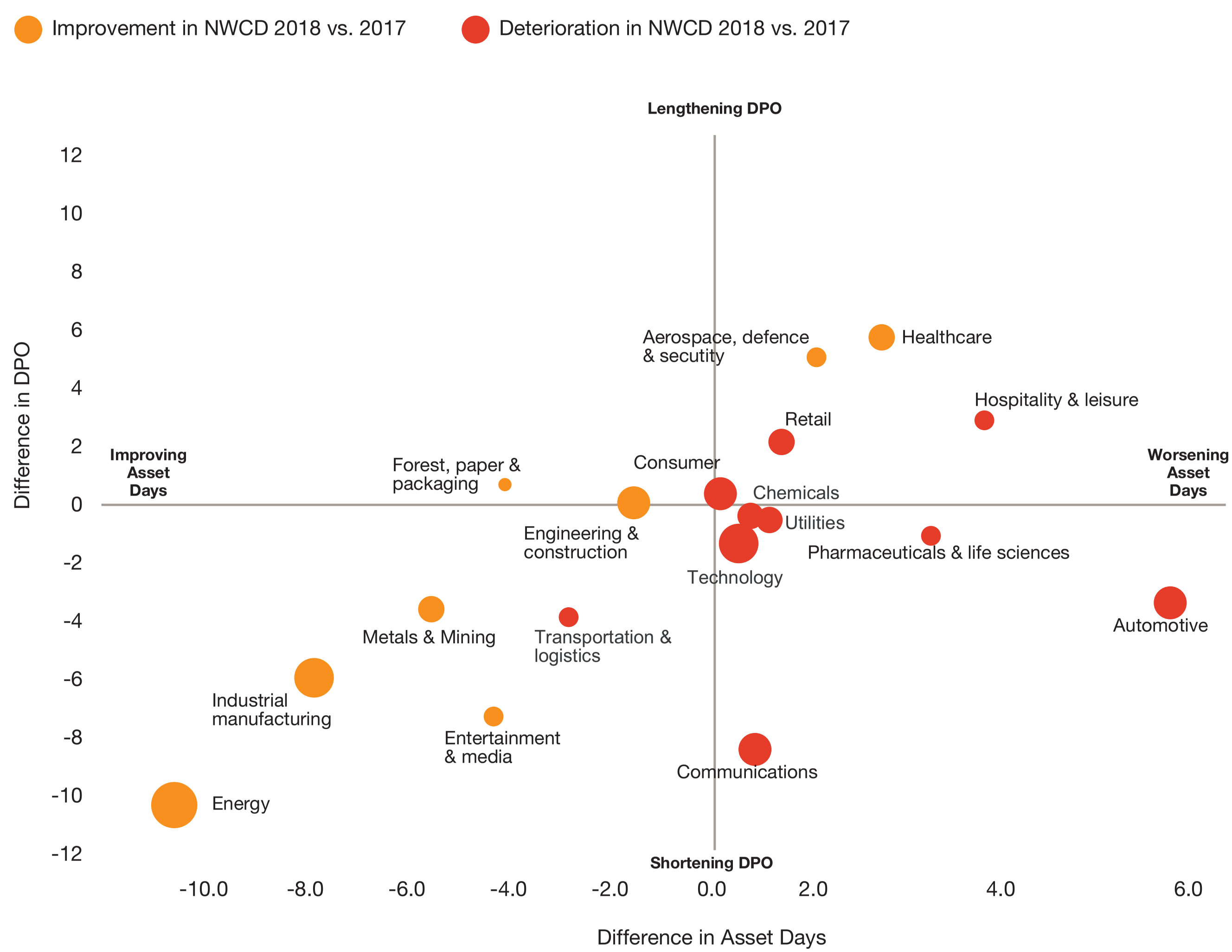
While at a global level DSO and DIO have declined, this is only the case for seven sectors, led by Energy (10.4-day reduction) and Industrial manufacturing (7.6-day reduction). Due to their large size, these sectors have a significant weighting that gives them a relatively strong influence on overall global performance.

This year we have seen seven sectors lengthen their payable terms, a reduction from the 11 sectors that did this in 2017. The Aerospace and Healthcare sectors have stretched payables to improve overall working capital performance, despite worsening asset performance.

The sectors in the bottom left-hand quadrant – Industrial manufacturing, Entertainment & Media, Energy, and Metals & Mining – have improved overall working capital performance despite a reduction in DPO. This suggests that these sectors are seeing the benefits of a more holistic approach to working capital improvement.

> **Automotive performance is under pressure from all angles, while Industrial Manufacturing and Energy have seen improvement despite shortening DPO.**

DPO/Asset days



Asset days = (trade receivables and inventory)/revenue *365

14-AtchA-13

> **Consumer companies are the only sector where the top quartile has improved and the bottom quartile has worsened.**

A large gap between the best and the rest

Data from the past five years indicates tha the gap between the highest and lowest working capital performers has stayed relatively stable at a global level, increasing by just 0.2 days.

At a more detailed level, all metrics have seen the performance gap widen. With DSO, the gap has increased by 0.6 days, driven by the bottom quartile worsening by 1.5 days and the top quartile worsening by 0.9 days. Similarly, the DIO gap has grown by 1.4 days. This has been driven by an improvement in the top quartile of 0.2 days and a decline in the bottom quartile of 1.2 days.

DPO is the only metric where both the top and bottom quartile have improved. However, the significant improvement in the top quartile of 2.7 days has outpaced the 0.3 day improvement in the bottom quartile.

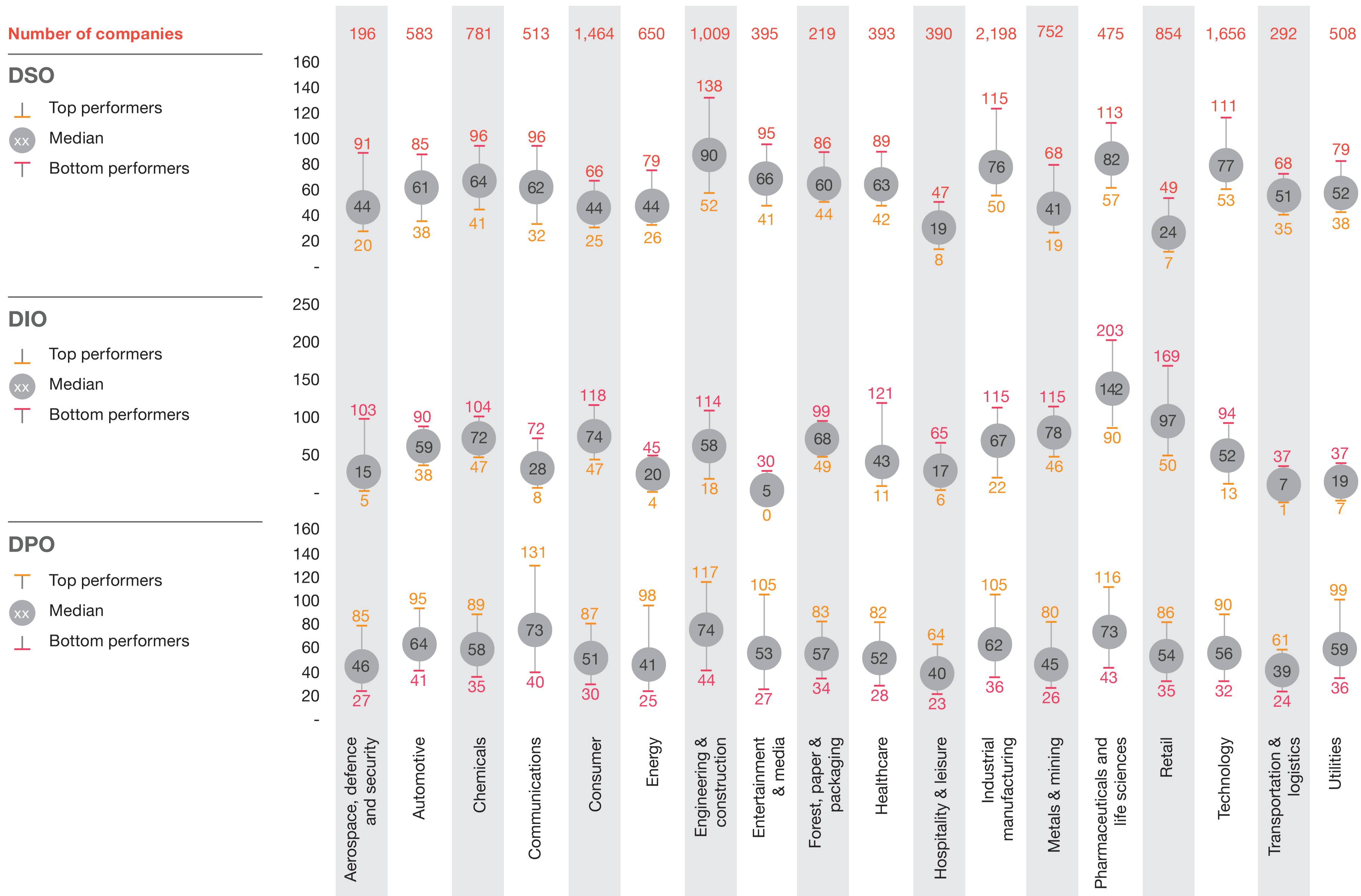
This overall trend is not consistent across industries, either in terms of the size of the gap or the degree of change from the prior year. For example, Aerospace, Defence & Security has a gap of 119 days between the top and bottom quartiles, the largest of any sector. By contrast, the gap in Transportation & Logistics is just 34 days.

Some sectors have seen the gap narrow.

- Healthcare has seen a reduction in the gap of 6.1 days. This has been driven by a small decrease in performance in the bottom quartile of 0.2 days, compared to a large decline in performance of the top quartile companies of 6.3 days.
- Utilities has seen the gap decrease by 5.8 days, driven by an improvement in the bottom quartile of 1.7 days, while the top quartile has declined by 4 days.

Conversely, some sectors have seen the opposite trend, with the gap widening.

- Pharmaceuticals and Life Sciences has seen an increase in the gap of 4.7 days, driven by worsening performance in the bottom quartile of 9.4 days.
- Consumer companies are the only sector where the top quartile has improved and the bottom quartile has worsened, leading to an increase in the gap to 4.8 days.


Number of companies
DSO
Top performers
Median
Bottom performers
DIO
Top performers
Median
Bottom performers
DPO
Top performers
Median
Bottom performers
196
583
781
513
1,464
650
1,009
395
219
393
390
2,198
752
475
854
1,656
292
508
Aerospace, defence and security
Automotive
Chemicals
Communications
Consumer
Energy
Engineering & construction
Entertainment & media
Forest, paper & packaging
Healthcare
Hospitality & leisure
Industrial manufacturing
Metals & mining
Pharmaceuticals and life sciences
Retail
Technology
Transportation & logistics
Utilities

Unlocking cash in the digital age

Digital technologies have been a driver of innovation and transformation for many aspects of business, across industries. This year's 22nd PwC Annual Global CEO Survey found that 72% of UK CEOs agree that key enablers and disruptors such as AI will have a significant impact on the way they do business in the next five years.

Harnessing the power of technologies such as data analytics, artificial intelligence (AI) and robotic process automation (RPA) is also becoming increasingly central to the optimisation of working capital.

Digital enablers have the potential to overcome the complexity and fragmentation that have historically hindered companies' working capital performance. Consumer markets such as retail and automotive present good examples of this potential. Both sectors have been struggling in the last several years with deterioration in working capital ratios, as well as limited visibility along their entire supply chain. Companies in both industries have found that predictive analytics and AI can be deployed to expand forecasting models to include an ever-wider range of data points, from the latest demand data to what's trending on social media. As the diversity of data points grows, machine learning is helping to improve accuracy, which – for example – can help organisations identify and set the optimal inventory levels.

However, the overall adoption rates for digital enablers remain low, with many companies lacking the capability or understanding of how to use them to generate value. In PwC UK's work with clients, we see a number of areas that need to be on the working capital agenda to drive optimal performance:

- applying data analytics to transform information into insight and focus operational activity
- delivering immersive visualisation to finance, factory floor, commercial reps and procurement alike, building a shared awareness of the importance of cash
- deploying predictive analytics to enhance inventory models or the efficiency of customer collection processes
- using drone technology to achieve accelerated inventory count
- applying RPA to automate back-office processes, such as billing
- deploying AI algorithms to enable early payment to suppliers while managing dilution risk
- using behavioural economics and social media flags to prevent bad debts in Order to Cash processes and debt management
- fine-tuning ERP systems to accommodate leading practice processes and supplementing capability with specialist cloud-based applications where applicable.

We have seen many companies where deploying a data-centric and digitally-enabled working capital approach has delivered a significant improvement in performance. To start the journey to digitally-enhanced working capital practices, we believe executives need to think through four key steps:

1. Build your data foundation

2. Apply advanced analytics

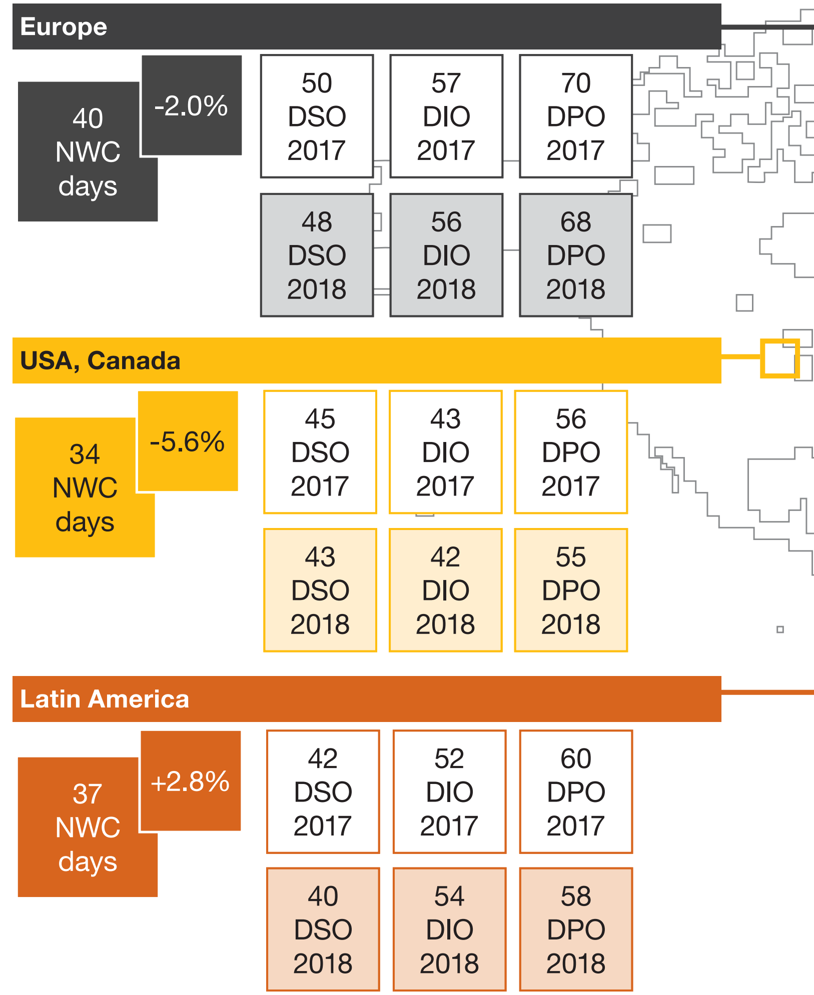
3. Improve business performance

4. Explore innovation opportunities

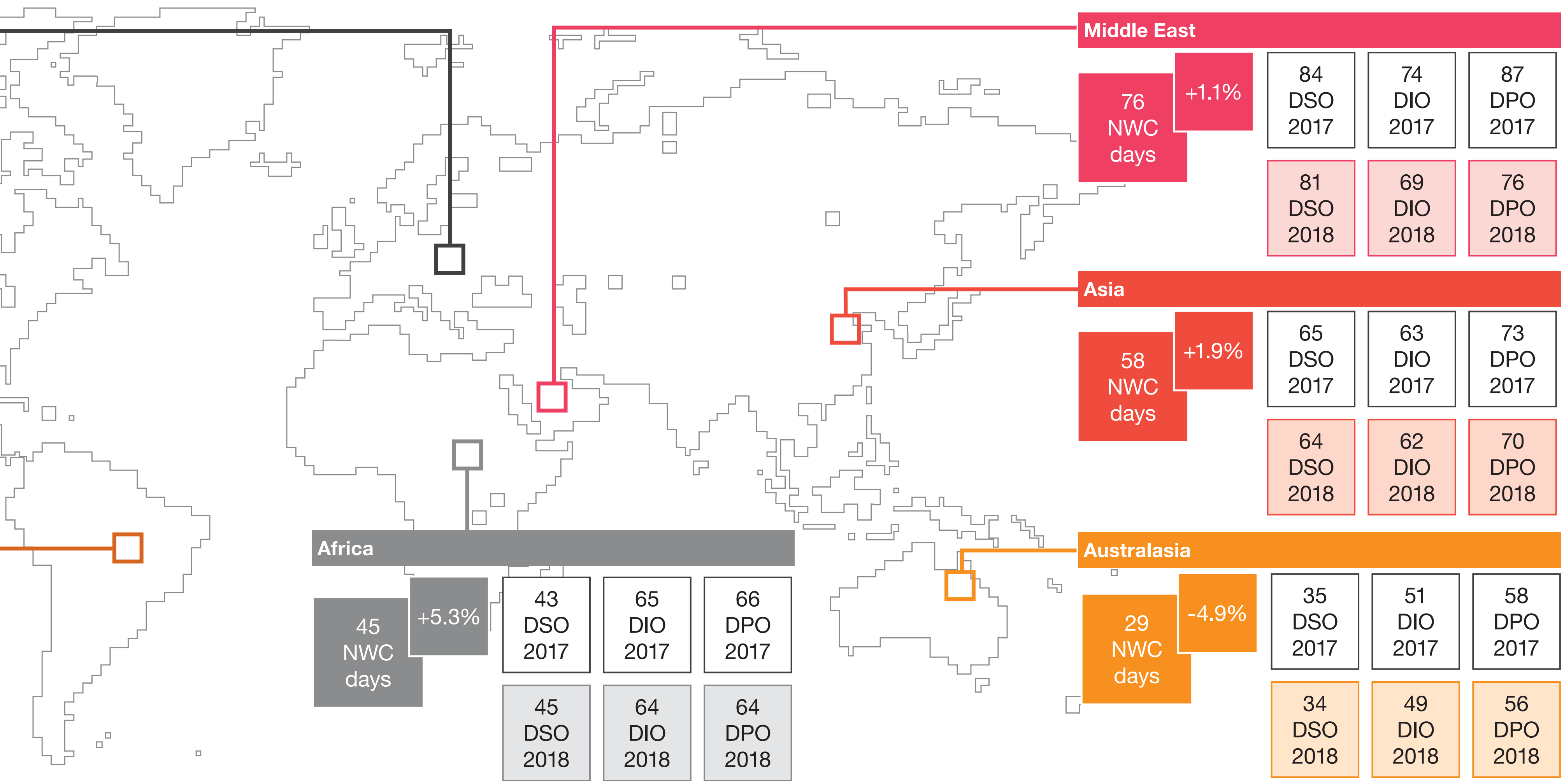
A global view

In an increasingly turbulent global trading environment, regional differences in working capital performance persist, driven by variations in payment methods, cultural norms and levels of cash maturity. Within any given region, there is a wide spectrum of working capital performance.

As we saw in last year's study, the continued rise in the impact and weighting of the Asian market also marks a shift in the centre of gravity with regard to working capital.



% = Year on year change


Middle East
76
NWC
days
+1.1%
84
DSO
2017
74
DIO
2017
87
DPO
2017
81
DSO
2018
69
DIO
2018
76
DPO
2018
Asia
58
NWC
days
+1.9%
65
DSO
2017
63
DIO
2017
73
DPO
2017
64
DSO
2018
62
DIO
2018
70
DPO
2018
Africa
45
NWC
days
+5.3%
43
DSO
2017
65
DIO
2017
66
DPO
2017
45
DSO
2018
64
DIO
2018
64
DPO
2018
Australasia
29
NWC
days
-4.9%
35
DSO
2017
51
DIO
2017
58
DPO
2017
34
DSO
2018
49
DIO
2018
56
DPO
2018

A view from Europe: a need to focus on “value preservation”

> **Net Working Capital days in the UK has deteriorated at a rate of 6% per year over the past five years, while the EU as a whole has seen Net Working Capital days deteriorate at a lower average rate of 1% per year.**

Overall working capital performance across Europe has seen a steady but marginal increase in terms of Net Working Capital days over the past five years.

However, there are major events on the horizon that have the potential to impact working capital performance in the region, including Brexit and the slowdown in major economies such as Germany.

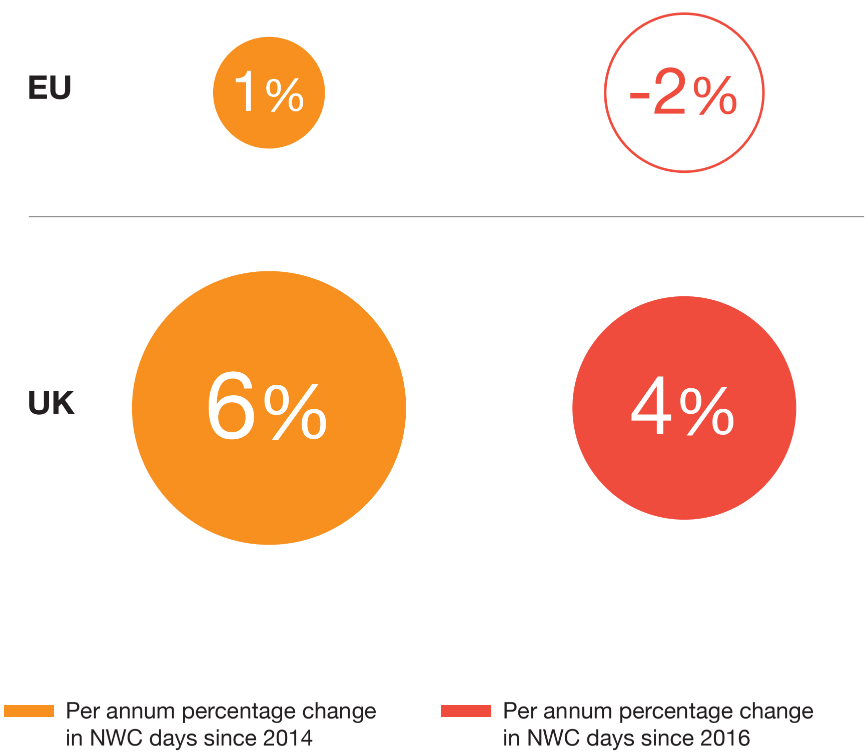
Historically, the UK has been more cash-focused than continental Europe, and it continues to exhibit more efficient (i.e. lower) levels of working capital. However, Net Working Capital days in the UK has deteriorated at a rate of 6% per year over the past five years, while the EU as a whole has seen Net Working Capital days deteriorate at a lower average rate of 1% per year. This has been driven by upward pressure on working capital, especially in France and Germany, where working capital days have been increasing by 5% year on year.

In contrast, the UK has seen a rise of 4% per year since 2016 – a trend that holds true across all the individual elements of working capital. Receivables days have grown twice as fast in the UK as in the EU27, while inventory days have deteriorated faster in the UK.

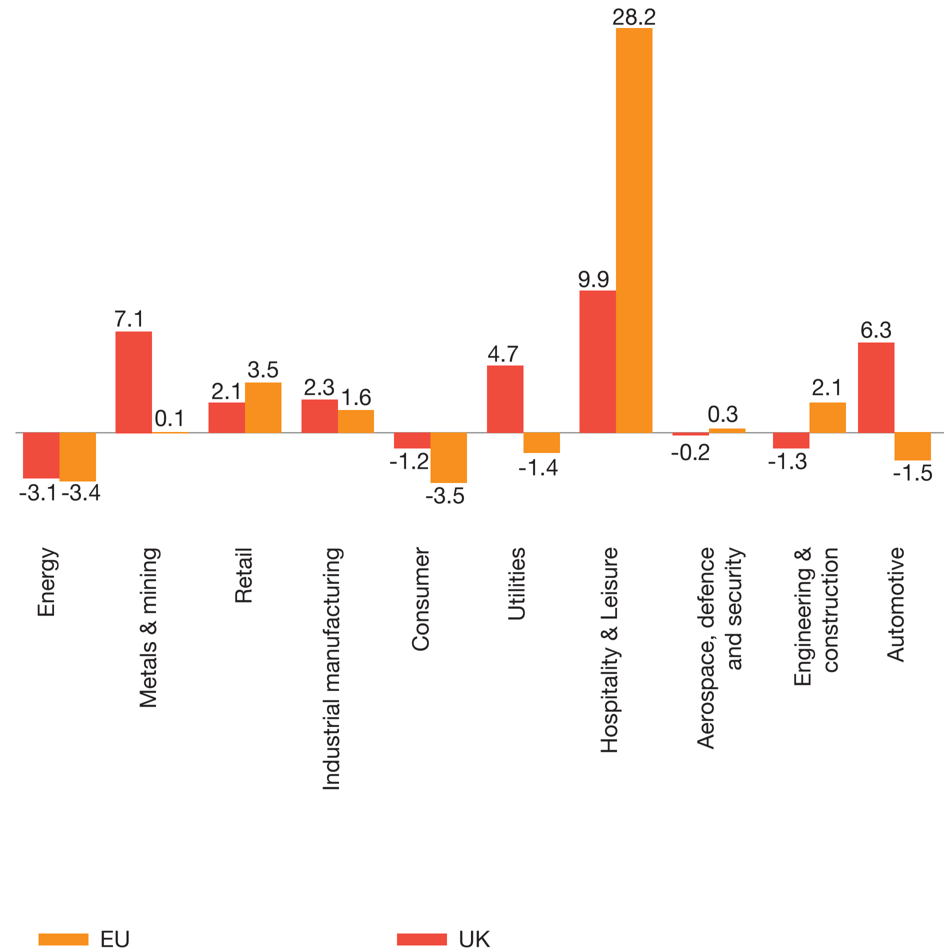
Some industries have been assessed as more at risk than others, as our findings indicate:

- 59% of sectors in the UK are still outperforming the EU27
- However, six of the largest 10 sectors in terms of revenue in the UK have seen a deterioration in working capital
- The largest relative deteriorations have occurred in the Metals & Mining, Hospitality, and Automotive sectors
- Retail and Automotive also exhibit lower working capital performance than other sectors, as well as experiencing a more significant deterioration in performance in the UK than the EU27
- The EU27 have now caught up with the UK in terms of operational cash flow performance. Since 2016, operational cash flow as a percentage of revenue has deteriorated by 2% per year in the UK. CAPEX has also deteriorated in the UK by 5% per year since 2016, and is now at its lowest level for the past five years. This suggests that keeping control of working capital is becoming increasingly important.

Rate of change in Net Working Capital days



EU vs UK per annum percentage change in Net Working Capital days from 2014 to 2018



6%

In 2018, there was a significant improvement of 6%, driven by DSO and DIO.

25%

Over the past five years, the Consumer and Healthcare sectors have seen improvements in working capital.

A view from North America

Working capital performance in North America has been relatively flat over the past five years, with an overall 2% increase in investment in working capital.

Interestingly, both DSO and DIO performance have declined by approximately 8% each, offset by a 15% improvement in DPO. This is not surprising, given the market trend towards companies extending terms with their suppliers and introducing other techniques.

In 2018, there was a significant improvement of 6%, driven by DSO and DIO of 4% and 3% respectively offset by a 1% decline in DPO performance. There are a number of possible explanations for this: DPO increases may have subsided, while companies might be beginning to address their large investments in accounts receivable and inventory to further streamline their balance sheets.

Over the past five years, the Consumer and Healthcare sectors have seen improvements of nearly 25% in working capital, while Energy has experienced a 50% increase. In 2018, some interesting differences have also emerged between different industries:

- Energy and Healthcare have experienced the largest improvements in working capital, with double-digit decreases year-on-year.
- Other sectors showing signs of improvement include Manufacturing, Consumer, Technology, and Utilities, with notable decreases in the high-single digits.
- The Communications and Automotive industries were the key outliers, with net increases in working capital of around 10%.
- Despite the low interest rate environment, the uncertainty about the global economy and the fact that companies would rather redeploy working capital to more productive uses, working capital improvement should become a greater focus for North American companies looking to unlock cash, while at the same time driving operational excellence and making themselves fitter for growth.

A view from Asia

Over the past five years, the Asia Pacific region has shown a slight deterioration in overall NWC performance.

DSO has increased from 60 to 64 days, but this is matched by a similar rise in DPO from 66 days to 70 days. The market fundamentals having a direct impact on working capital performance in the region include, the ongoing devaluation of some major Asian currencies; the relatively higher interest rates in Asian markets; the uncertainty and nervousness around the China/US trade war.

From an industry perspective, overall NWC days have worsened in five out of Asia's 10 largest sectors, most prominently in Automotive, Communications, and Retail. We judge the overall results for the region are materially driven by its largest economy—China—which has shown a mild deterioration in overall working capital performance. With China's GDP growth running at a five-year low of 6.6%, its economy is facing intensifying downward pressure and a resulting squeeze on liquidity.

Against this background, China's NWC days have increased by 2%, a rise we assess is mainly attributable to a 14% surge in DSO. The five-year average DPO in China is 21 days higher than the average for the region, with companies in China habitually paying suppliers significantly later than in most other countries in the region.

The need for cash is increasing

Over the past five years, CAPEX spending relative to revenue has declined at a compound annual rate of 3.0%.

In the past four years, companies have also been experiencing a more gradual decline in operating cash flow relative to revenue.

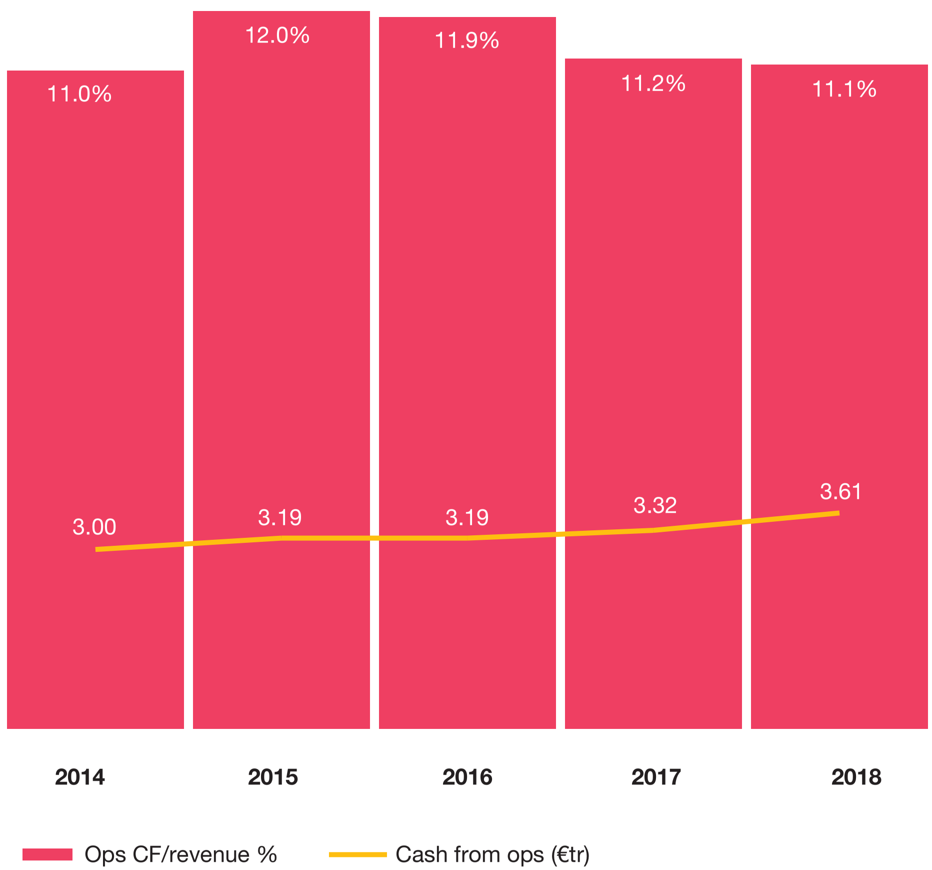
While both operating cash flow and CAPEX are increasing in absolute terms, neither is keeping pace with rising global revenue levels.

In absolute terms, the increase in CAPEX represents only 55% of the increase in operating cash flows, illustrating the competing demands on companies' cash.

Investment may help in the current uncertain global trading environment, both to exploit opportunities and to protect against the impacts of disruption in rapidly-changing markets.

With this in mind, addressing Working Capital structurally and sustainably is an opportunity that companies need to prioritise.

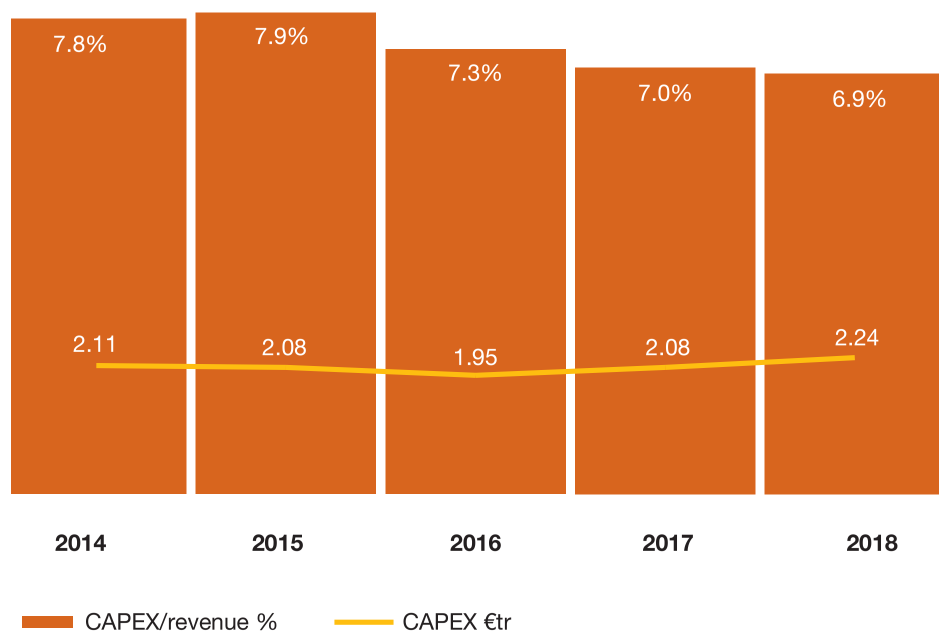
Operating cash flow/revenue trend



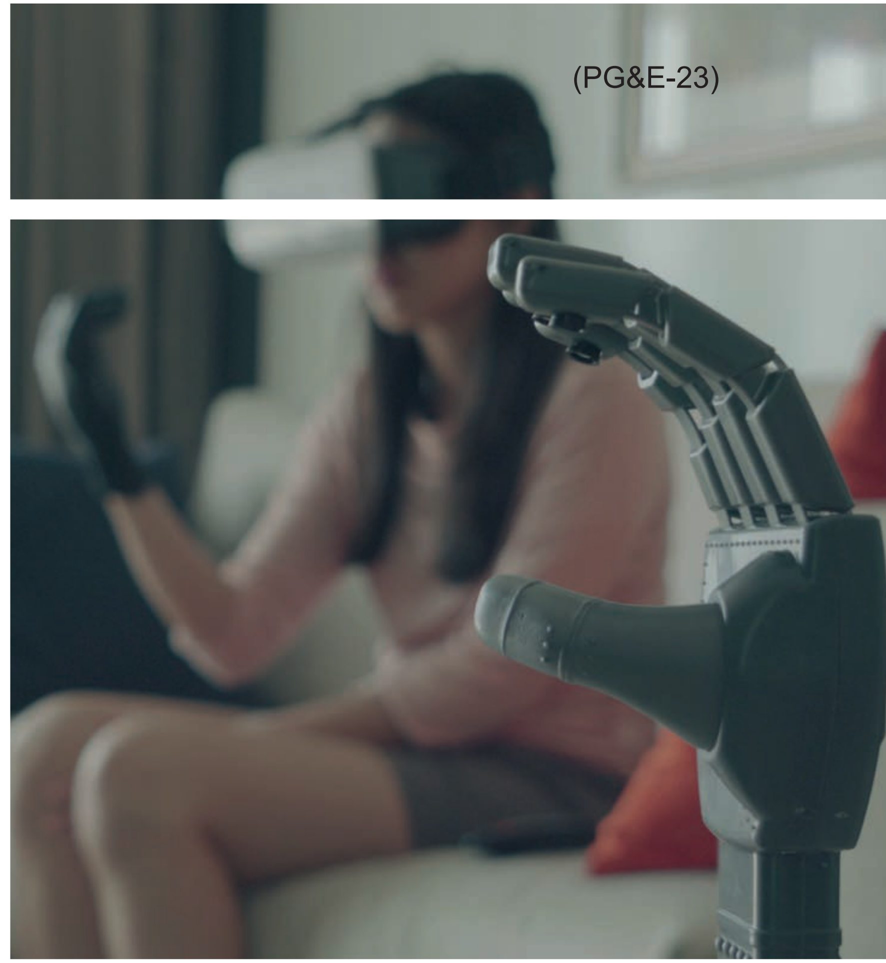
CAPEX/revenue trend

-3.0%

Compound year-on-year decline 2014-2018



How we can help

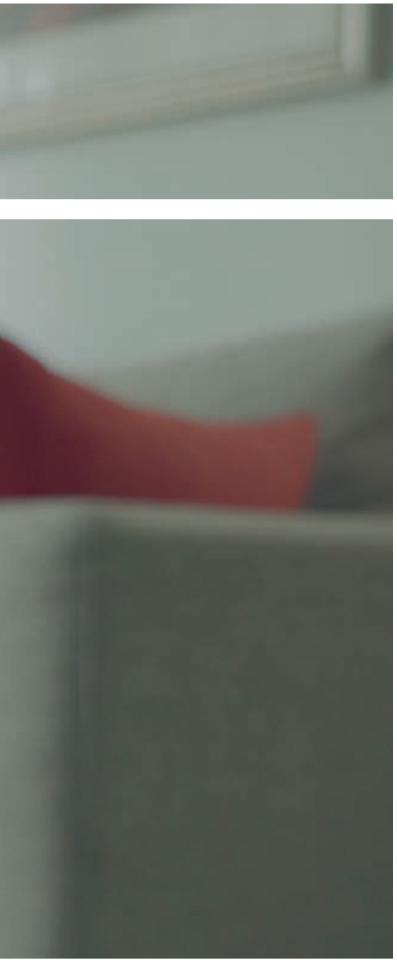


We help our clients to:

- identify and realise cash and cost benefits across the end-to-end value chain
- optimise operational processes that underpin the working capital cycle
- implement digital working capital solutions and data analytics
- achieve rapid cash conservation in crisis situations
- create a 'cash culture' and upskill the organisation through our working capital academy
- roll out trade and supply chain financing solutions.

Our Working Capital improvement approach

Quick scan → **Diagnostic** → **Design** → **Implementation**



Where and how we could help you to release cash from Working Capital

Accounts receivable

- Tailored, proactive collections
- Credit risk policies
- Aligned and optimised customer terms
- Billing timeliness & quality
- Contract & milestone management
- Systematic dispute resolution
- Dispute root cause elimination
- “Surge” operational bandwidth
- Negotiation strategy and support

Inventory

- Lean & agile supply chain strategies
- Global coordination
- Forecasting techniques
- Production planning
- Inventory tracking
- Balancing cost, cash and service level considerations
- Inventory parameters & controls defining target stock

Accounts payable

- Consolidated spending
- Increasing control with centre-led procurement
- Helping avoid leakage with purchasing channels
- Payment terms
- Supply chain finance benefits assessment & implementation
- Helping eradicate early payments
- Payment methods
- Negotiation strategy and support

Authors

Europe


Daniel Windaus
Partner, PwC UK
T: +44 7725 633 420
E: daniel.windaus@pwc.com


Stephen Tebbett
Partner, PwC UK
T: +44 7717 782 240
E: stephen.tebbett@pwc.com


Henry Rosier
Working Capital, PwC UK
T: +44 7808 796 915
E: henry.n.rosier@pwc.com

North America


Joe Rafuse
Partner, PwC Canada
T: +1 416 671 2273
E: joe.rafuse@pwc.com


Rob Vettoretti
Managing Director, PwC USA
T: +1 (678) 296 9465
E: r.vettoretti@pwc.com

Asia


Peter Greaves
Partner, PwC Hong Kong
T: +852 9557 7700
E: peter.greaves@hk.pwc.com

Global Working Capital contacts

Denmark
Rene Brandt Jensen
E: rene.brandt.jensen@dk.pwc.com

Finland
Michael Hardy
E: michael.hardy@fi.pwc.com

France
François Guilbaud
E: francois.guilbaud@pwc.com

Germany and Austria
Rob Kortman
E: rob.kortman@pwc.com

Ireland
Declan McDonald
E: declan.mcdonald@ie.pwc.com

Italy
Paolo Menafoglio
E: paolo.menafoglio@pwc.com

Japan
Michio Ikeda
E: michio.ikeda@pwc.com

Malaysia/Vietnam
Ganesh Gunaratnam
E: ganesh.gunaratnam@pwc.com

Middle East
Mihir Bhatt
E: mihir.bhatt@ae.pwc.com

Norway
Robert Dijkstra
E: robert.dijkstra@pwc.com

Poland
Pawel Dżurak
E: pawel.dzurak@pl.pwc.com

Russia
Alexey Sizov
E: alexey.sizov@ru.pwc.com

Spain
Arnaud Ojeda
E: arnaud.ojeda@pwc.com

Switzerland
Benjamin Rutz
E: benjamin.rutz@ch.pwc.com

The Netherlands
Danny Siemes
danny.siemes@pwc.com

pwc.com/workingcapitalopportunity

PACIFIC GAS AND ELECTRIC COMPANY

CHAPTER 14

ATTACHMENT B

PWC WORKING CAPITAL STUDY 21/22

Working Capital Study 21/22

From recovery to growth in the face of supply chain instability

pwc

Contents

Executive summary

The corporate focus is shifting from stabilise and survive to recovery and growth. But unstable supply chains are disrupting operations and heightening the pressure on working capital – the cash needed to run the day-to-day operations of any business.

Why it matters

Net working capital (NWC) days reached a record high in 2020, driven by the shock and uncertainty of the COVID 19 pandemic. Amid ongoing supply chain disruption, managing and right-sizing working capital will continue to be a major challenge. While many of the spikes in working capital had unwound by mid-2021, the ending of government support, elevated levels of debt and the decrease in returns all mean that capital efficiency has to be front of mind as we go into 2022.

The pandemic exposed the slow reaction of supply chains to external shocks, leading to a significant rise in NWC during Q2 and Q3 2020. This lack of agility in adapting working capital levels to disruptive external events is a concern as we face continued challenges in the global supply chain.

With ongoing instability in the global supply chain, including port closures, limited shipping lane availability, lack of HGV drivers, and shortage of raw materials, managing inventory is a key focus. Instances of both excess and insufficient stock are higher than ever. The heightened complexity and lack of visibility over most supply chains mean the move from 'just in time' to 'just in case' planning in order to manage supply risk may bring further working capital challenges.

That is why 65% of executives in our recent Business Survey named working capital efficiency as a critical objective for change management and restructuring activities.

65%

of executives in our recent Business Survey named working capital efficiency as a critical objective for change management and restructuring activities.

What the survey tells us

Net Working Capital

5%

spike in NWC days

2020 saw the largest movement in NWC days in five years, driven by a revenue decline which nominal working capital has not been able to respond to. This movement has taken NWC days to a five-year-high.

Payment morale has deteriorated

7%

increase in both days sales outstanding (DSO) and days payables outstanding (DPO) annually

Rather than being a structural change in how working capital is managed, these movements largely stem from poor payment practices on both sides of the fence.

High debt, low returns

Net debt is at a five-year-high

Companies have also experienced the lowest return on invested capital (ROIC) over the same period.

14-AtchB-4

Supply jolt

63%

of respondents in manufacturing rank supply chain issues as a key concern.

While some companies may look to lengthen stock coverage to ensure supply, the risks of over and undershooting of inventories are high.

Inventory on the rise

6%

Up in 12 of 17 sectors analysed since Q2 2019 and 6% overall.

Many sectors have yet to return to their pre-pandemic level of performance.

Working capital efficiency critical

65%

of executives named working capital efficiency as the main objective for change management and restructuring activities.

The pandemic impacted Net Working Capital

14-AtchB-6

As anticipated in our previous study, the turmoil of the pandemic saw NWC days reaching a record high in 2020. Global revenues saw an 8% decline from two years before, which was a significant factor in the increase in NWC days.

The movement in working capital reflects what happens when companies look to pull short-term levers. DSO reached a five-year-high, increasing 7% annually to 54.1 days as customers delayed payments. At the same time, and partially as a knock-on impact, companies stretched their creditors, with DPO also increasing by 7%, breaking a four-year trend of shortening payment days. With increased uncertainty over demand and supply, inventory days also saw an increase of 5%. However, the impact wasn't felt evenly across all industries and regions, and the lack of agility to react to changes at pace will continue to be a significant driver of working capital.

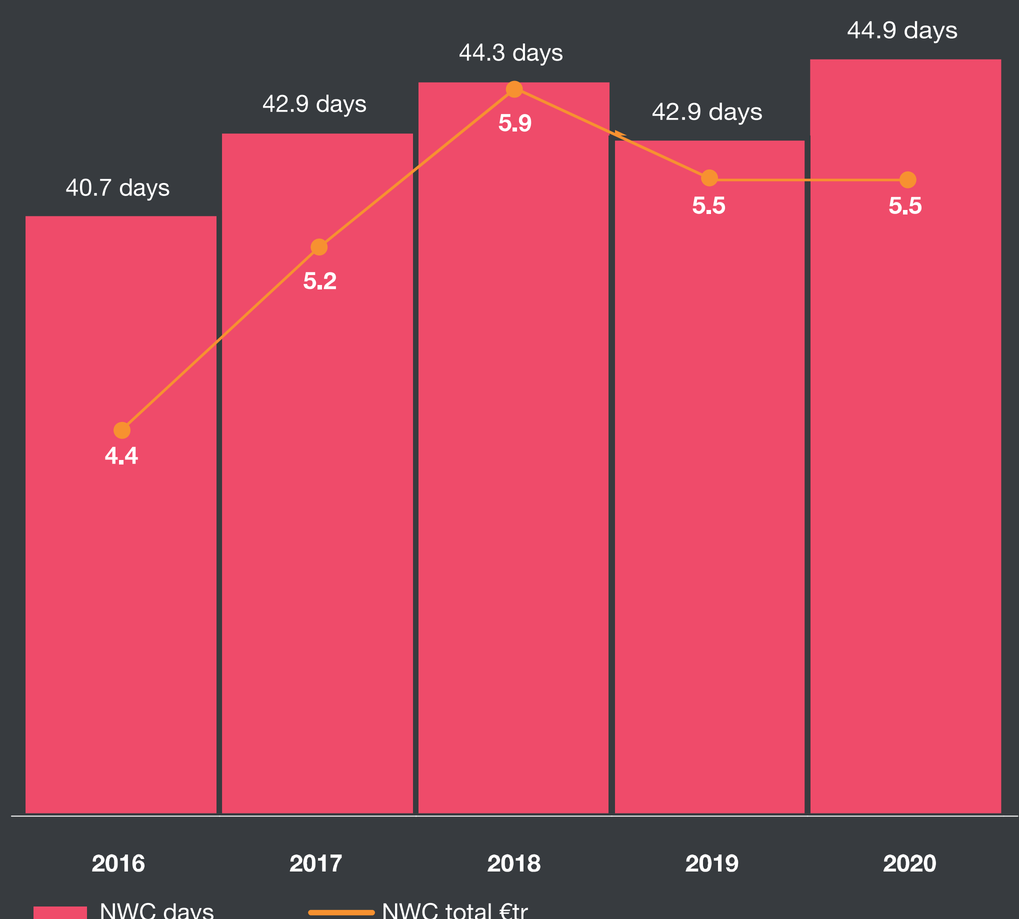
8%

decline in global revenues from two years prior.

5%

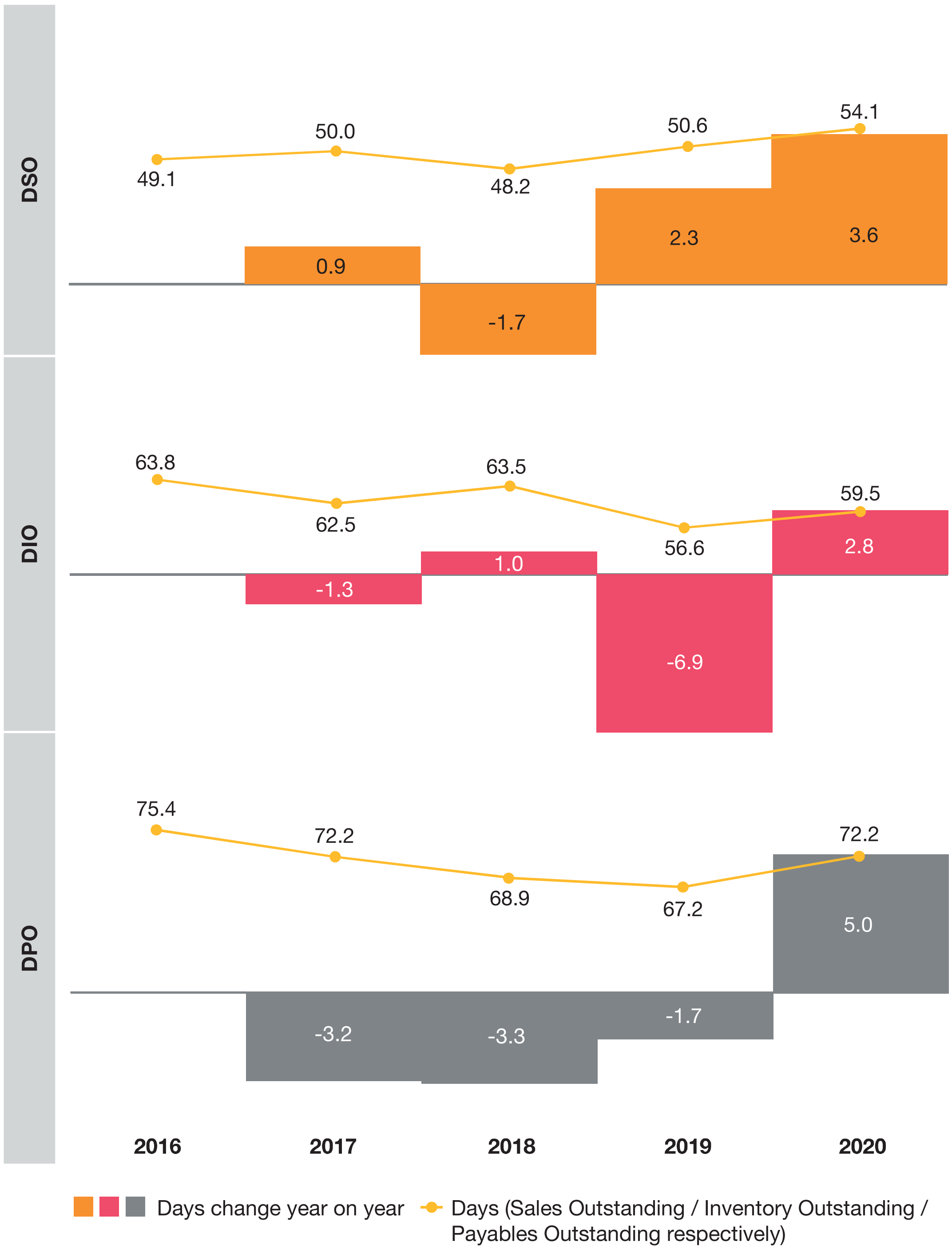
increase in inventory days.

Figure 1: Net working capital and working capital days



14-AtchB-7

Figure 2: DSO, DIO and DPO trends



While working capital consumed a larger portion of capital, significant government support and readily available debt have allowed many companies to sustain a strong cash position, for now at least. Cash days (represented as days of cover for operating expenses) have increased by 14 days to a five-year-high.

With the winding down of government support, it's important to keep a close eye on capital efficiency and liquidity. ROIC took a hit, dropping by 1.4% to its lowest level for five years. At the same time, net debt levels are at five-year-high.

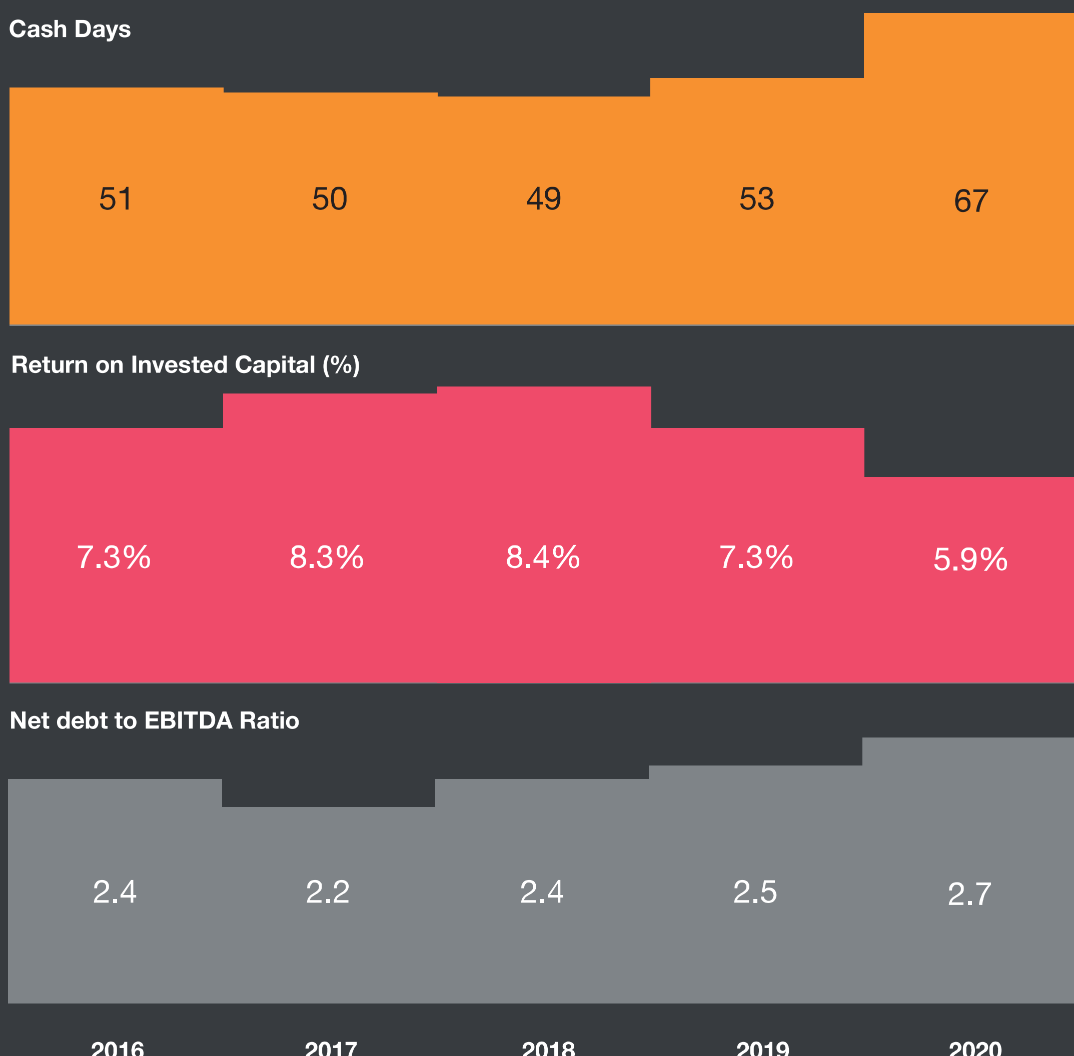
1.4%

drop in ROIC, its lowest level for five years.

8%

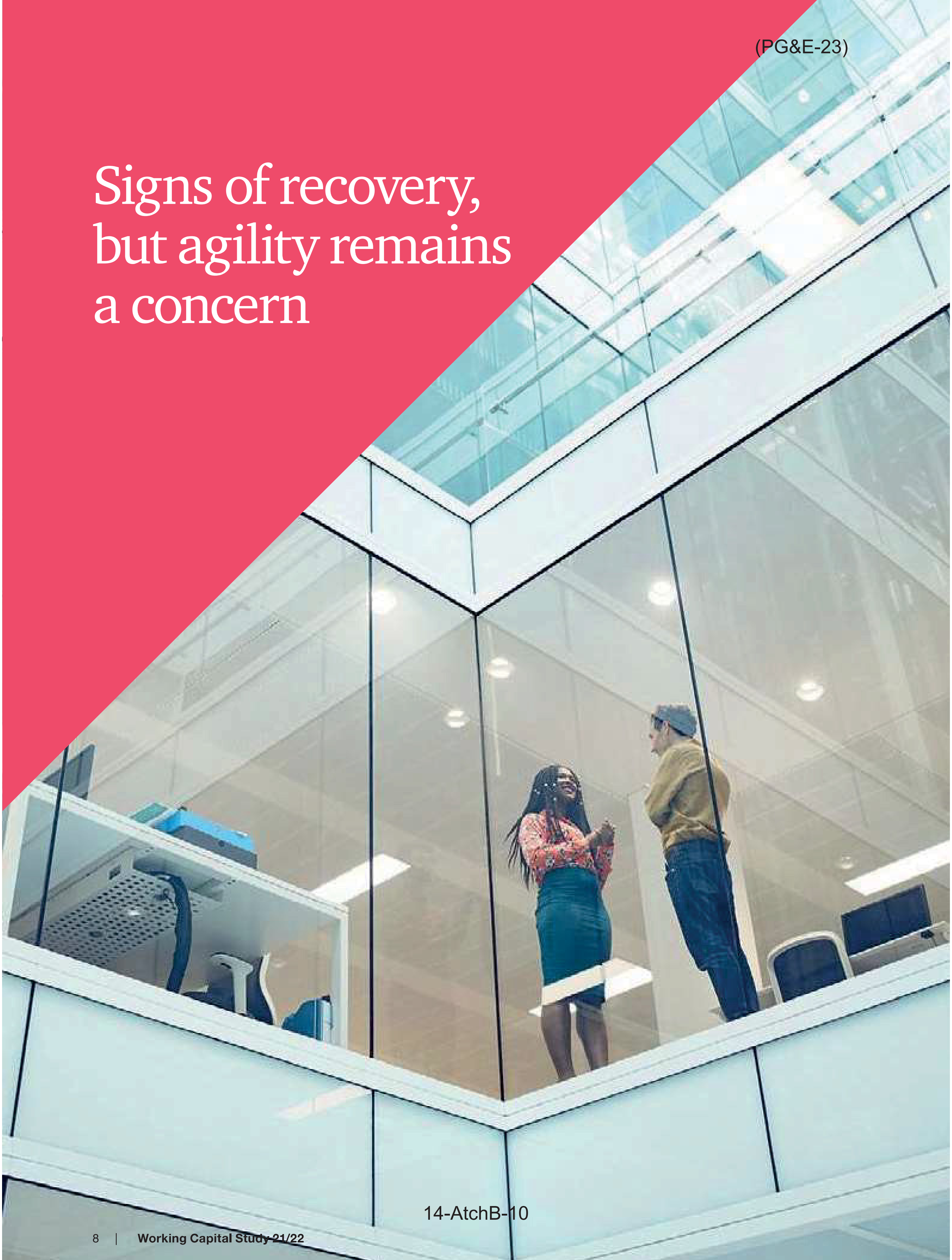
increase in Net debt to EBITDA ratio.

Figure 3: Liquidity and financial performance trend



> With the winding down of government support, it's important to keep a close eye on capital efficiency and liquidity.

Signs of recovery, but agility remains a concern



The deterioration in working capital performance reflected the exceptional volatility experienced by many companies. The pandemic has also exposed the slow reaction of supply chains to external shocks, leading to a significant spike in working capital days during Q2 and Q3 2020.

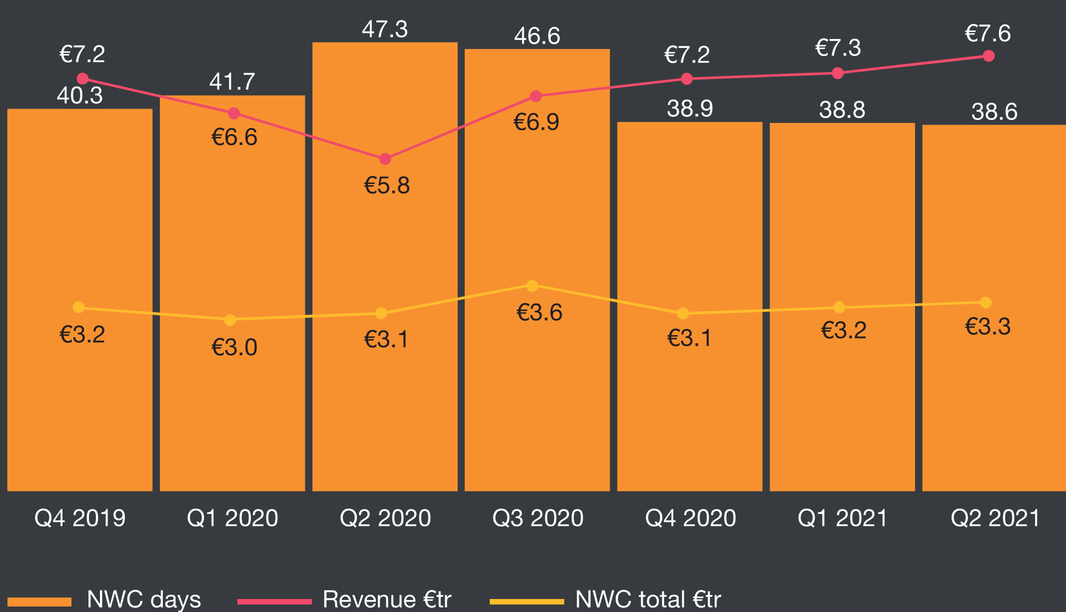
Since Q3 2020, there have been signs of recovery, with revenues growing above pre-pandemic levels. However, it's sobering to note how little the nominal value of working capital changed during one of the most significant demand and supply shocks for many years. This lack of agility to move with external events meant NWC days rose seven days above pre-pandemic levels at it's peak.

While overall NWC remained fairly flat, outside of a Q3 2020 peak, analysis of the components of nominal NWC reveals an interesting set of trends.

Inventory, which is a leading measure due to the need to build up stock up ahead of the return of revenue, saw a sharp increase of €0.6tn (22%) in Q3 2020 before declining in the next quarter. Even before the pandemic, there were growing concerns over global supply chains and availability of goods. The sharp decline in Q4 2020 may also be explained by scarcity rather than normalising inventory requirements. By Q2 2021, Inventories were up 7% from pre-pandemic levels.

> “
> Nominal working capital has been unresponsive.

Figure 4: Quarterly movements in revenue, net working capital and working capital days

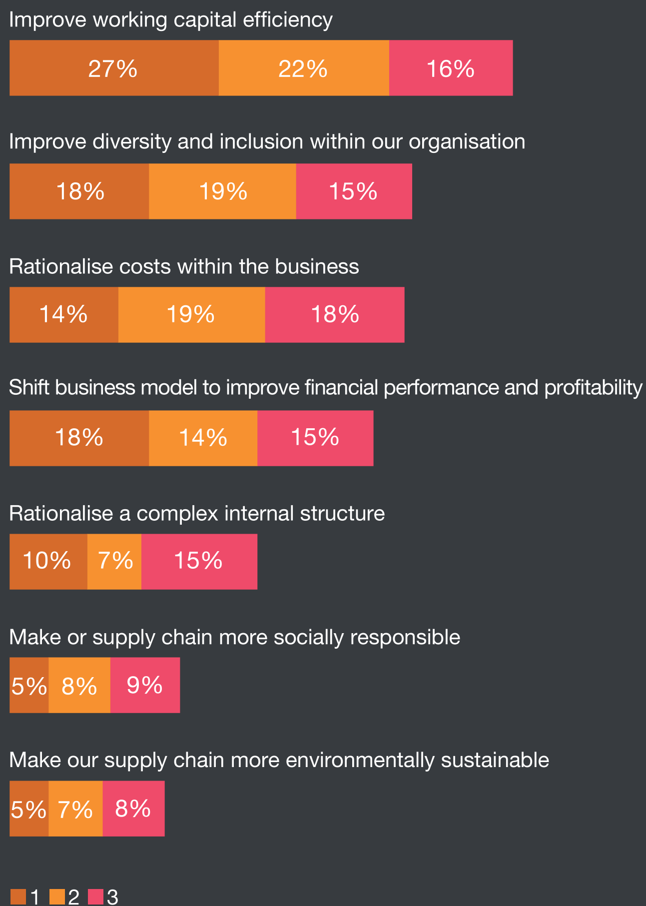


Receivables broadly tracked the direction of revenue, though were unable to move at the same pace. This meant that while nominally receivables declined in Q2 2020, DSO was at its peak, as longer payment terms and delinquent customers increased proportionally. Receivables then grew from Q2 2020 to Q2 2021, up by 8% from Q4 2020 levels.

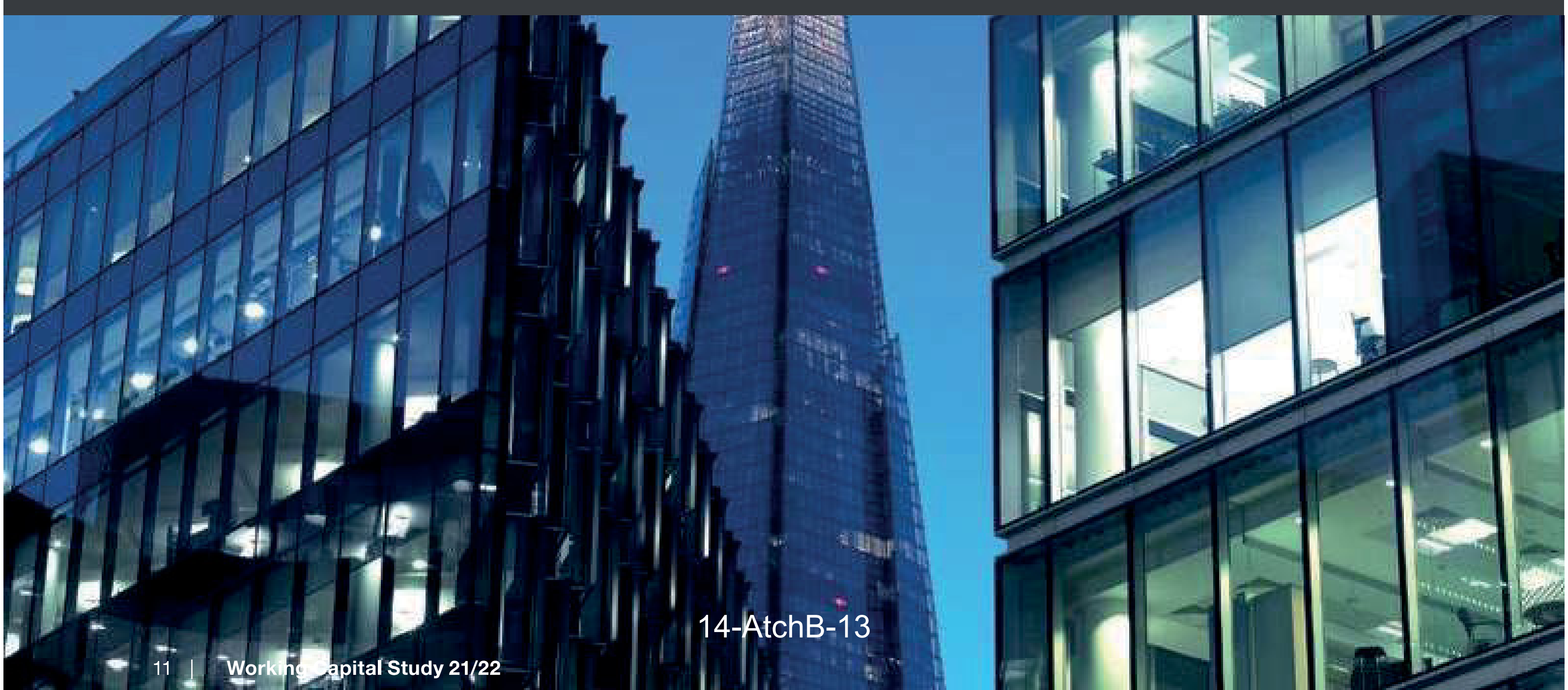
In Q3 2020, a similar but less exaggerated rise was seen in payables compared to the spike in inventory, aligning to goods and materials bought on credit. By Q2 2021, payables grew at a faster rate than other metrics, ending 12% up from Q4 2019, offsetting the increases in inventories and receivables. So it looks like the trend to stretching creditors to balance out working capital is back.

Figure 5: Quarterly DSO, DIO and DPO trend by Q2 and Q4 2019-2021

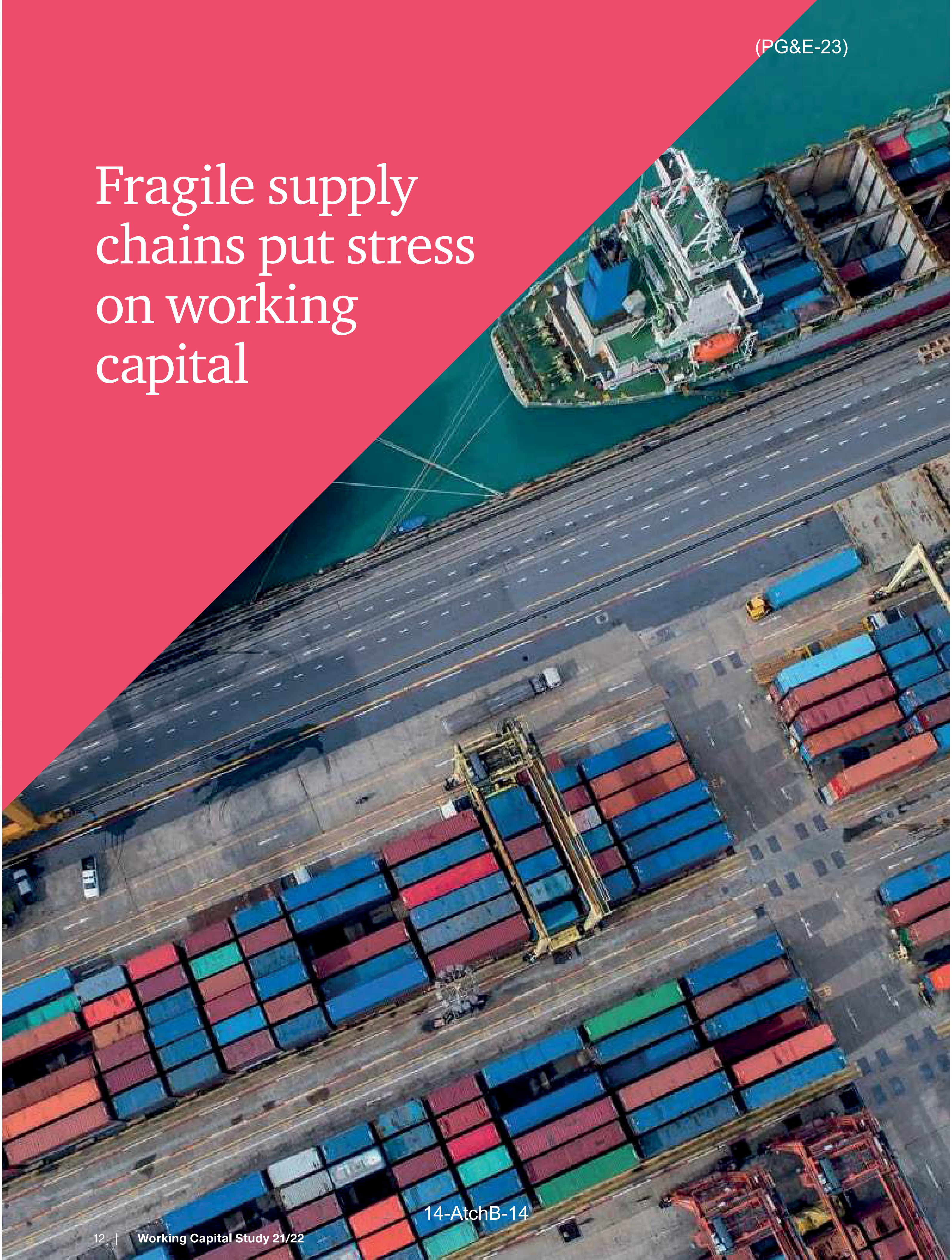
Figure 6: What are the objectives of your change management or restructuring? (rank 1 to 3)



Improving working capital efficiency is the main objective for change management and restructuring. Sixty-five percent of respondents ranked it within their top three motivations.



Fragile supply chains put stress on working capital



Continued disruption in global supply chains is having a major impact on working capital performance across sectors and regions. The list of drivers fuelling supply chain volatility is growing amid the ongoing impacts of COVID-19 on operations. These include Delta variant outbreaks in factories and ports in Asia, constraints on shipping lane availability, lack of HGV drivers, material shortages such as rare metals and semiconductor, as well as the energy crisis.

A perfect storm of supply constraints and rapidly changing consumer demand mean that the risk of excess is just as prevalent as the potential for insufficient stocking.

Companies are having to re-evaluate planning and production. Shortages of raw materials will inevitably result in stock shortages and operational disruptions in manufacturing businesses. Logistics volatility, as well as the drive to Net Zero, are likely to lead to an increase in nearshoring where possible, along with a heightened focus on the stability of critical external suppliers.

PwC's 2021 Manufacturing COO Pulse Survey found that 63% of respondents rank supply chain as a key concern. Some companies may look to lengthen stock coverage to ensure continuity of supply. But this may result in both over and undershooting risks, which may also have knock-on impacts further down the line, including strains on warehousing capacity and future obsolescence.

63%

rank supply chain high/very high priority

Figure 7: % selecting 'supply chain risk management' as a business priority in the next 1-2 years

> A perfect storm of supply constraints and rapidly changing consumer demand mean that the risk of excess is just as prevalent as the potential for insufficient stocking.

The impacts of volatility on supply chains, working capital and inventory especially have had different effects across sectors:

- **Aerospace & Defence:** While being a broad sector, it is heavily weighted towards the aircraft industry. The industry's long lead times and complex value chain were unable to respond within the first half of 2020, and even as we move into Q2 2021, inventory days are 10.9 days (19%) above 2019 levels.

- **Automotive:** The decline in revenue during 2020, along with long lead times, led to a peak in days inventory outstanding (DIO) of 74.4 days in Q2 2020, 23.6 days ahead of Q2 2019. While sector demand recovered, the supply constraints associated with the semiconductor shortage have limited trading recovery, while shortening inventory days, settling at 50 days by Q2 2021, 0.8 days below Q2 2019 levels.

- **Consumer:** The sector has seen major swings in demand. The electronics subsector also experienced particular pain from the semiconductor shortages. The result has been a volatile overall inventory position. This grew by 11 days from Q4 2019 to Q2 2020 (17%) as a result of a slight deterioration in quarterly trading.

- **Industrial manufacturing:** Inventory days rose by 6.8 days between Q2 2019 and Q2 2020 as inventory was unable to respond elastically to changes in demand. Manufacturers also felt significant pressure during this period as shoring up supply of materials became a critical issue. This trend was reversed by Q4 2020 and both revenue and inventories appear to have returned to pre-pandemic levels.

- **Retail:** Overall, the sector has shortened its inventory position. But fashion and luxury retailers saw their performance deteriorate and it is yet to fully recover, as discretionary retail was forced online, and fashion trends shifted.

Figure 8: Quarterly DIO trend by sector

Sector	Difference in DIO	% difference Q2 2019 to Q2 2021
Aerospace & Defence	10.9	19% ↗
Automotive	-0.9	-2% ↘
Chemicals	-6.9	-9% ↘
Consumer	0.6	1% ↗
Engineering & construction	-7.7	-9% ↘
Hospitality and leisure	10.9	35% ↗
Industrial manufacturing	-1.0	-2% ↘
Retail	-1.9	-3% ↘

*for sectors with material inventory components

Supply Chain Priorities for the next 2 years	Aerospace & Defence	Automotive	Consumer	Engineering & Construction	Industrial Manufacturing
1	Sourcing Reliability	Demand forecasting	Supply Chain Transparency	Cost Control	Supply Chain Transparency
2	Demand forecasting	Cost Control	Cost Control	Sourcing Reliability	Demand forecasting
3	Cost Control	Vertical Integration	Vertical Integration	Vertical Integration	Cost Control

PwC 2021 Manufacturing COO Pulse Survey*

Moving From just-in-time to just-in-case

During times of uncertain demand, agility in the supply chain and inventories are more important than ever. At the same time, the ability to shore up supply is essential. The sight of a container ship stuck in the Suez Canal has become the most vivid symbol of the supply chain vulnerabilities exacerbated by the pandemic. The sheer complexity of today's supply chains presents a risk in itself. A lack of visibility and end-to-end understanding deprives an organisation of the insights that it will rely on to prevent future shortages or quality concerns.

1 **Know your suppliers**
Many firms only have a superficial understanding of their suppliers, and many fail to look beyond Tier 1. Supply chain mapping will help you understand how suppliers across every tier integrate and interact, and allow you to spot geographical and speciality gaps.

2 **Deploy data to view suppliers across key domains**
Monitor supplier strength through multiple perspectives, including geometrics, financial health, operational agility, commercial performance, regulatory performance, legal standing, ethics, sustainability, governance and cyber resilience.

3 **Create a response plan**
Data alerts you to imminent shortages, quality deficiencies and other potential risks. It allows you to get ahead of the curve. A timely and proactive response depends on preparation and requires a holistic and cross-functional approach that goes beyond the supply chain professional.

4 **Drive value at the same time**
While building supply chain resilience is important, it's possible to create synergies by linking it into broader initiatives, such as contract lifecycle management, optimising procurement spend and optimising the right safety and cycle stock.

Proactive – Preparing for the next crisis to mitigate risks

Visibility & transparency	Flexibility	Integrated information	Risk managment	Sustainability	Tailored commercial arrangements
• Real time supply chain mapping • Increasing visibility of vulnerabilities and interdependencies	• Multi-sourced, agile and buffered supply chain. • Responsiveness to changes in demand and supply	Live cross-functional data to: • Forecast demand • Drive efficiencies • Collaborate	• Key external and internal indicators across risk domains • Forecasting and responding to disruptions	Holistic resilience approach involving: • ESG • Cyber • Evolving risks	Aligning supplier relationships to: • Meet your risk appetite • Maximise commercial performance

Proactive – Flexibility in adapting to supply chain shocks to accelerate recovery

Technology enabled insights within the Supply Resilience tool will enable robust governance of the key resilience pillars

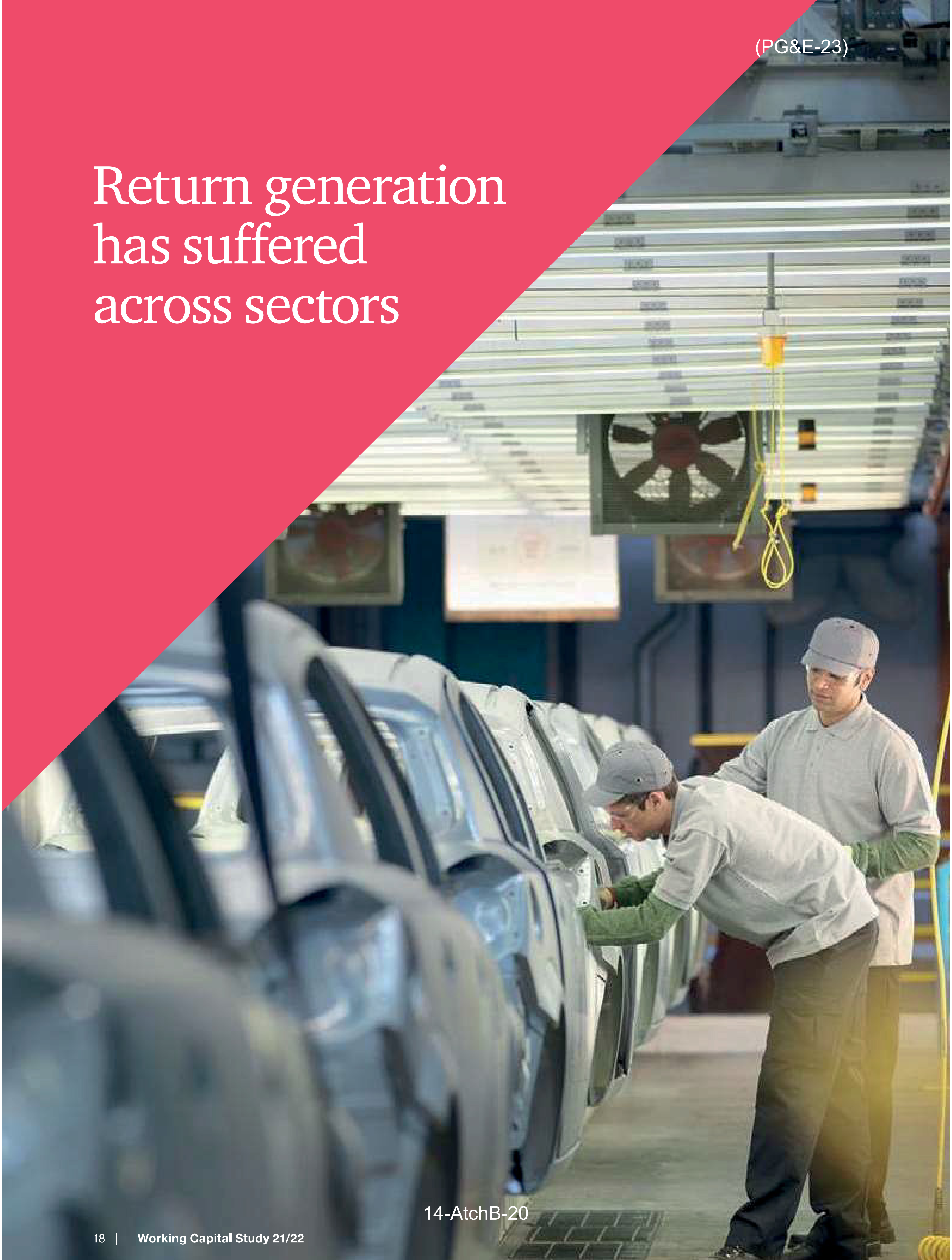
Resilience indicators

Criticality indicators

Supply chain Partnerships

Strategic intervention

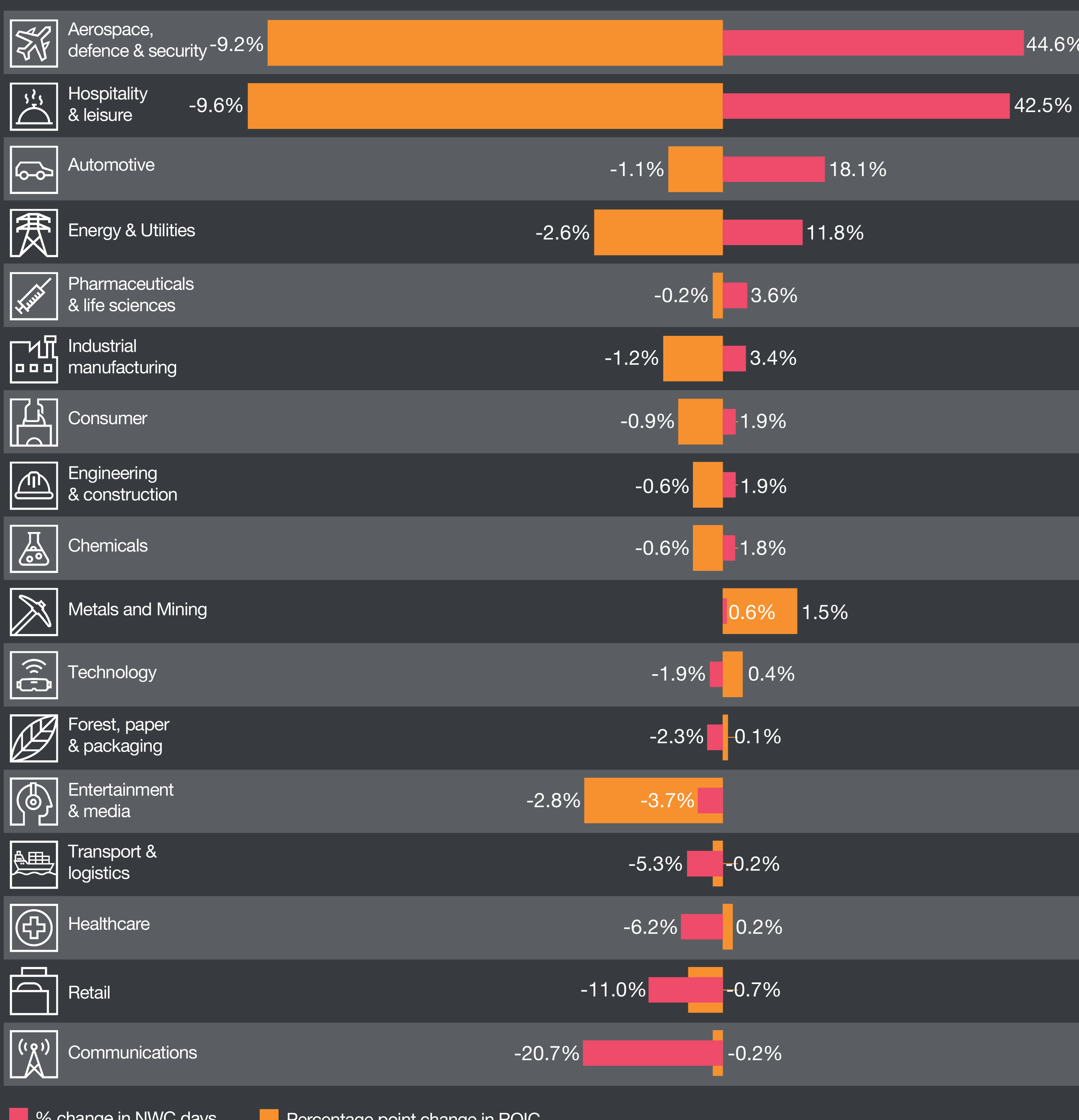
Return generation has suffered across sectors



Between 2019 and 2020, 10 out of 17 sectors saw a deterioration in NWC days. Four of these sectors saw a double-digit deterioration – Aerospace & Defence, Hospitality & Leisure, Automotive and Energy & Utilities, reflecting the shock suffered in these sectors during the pandemic.

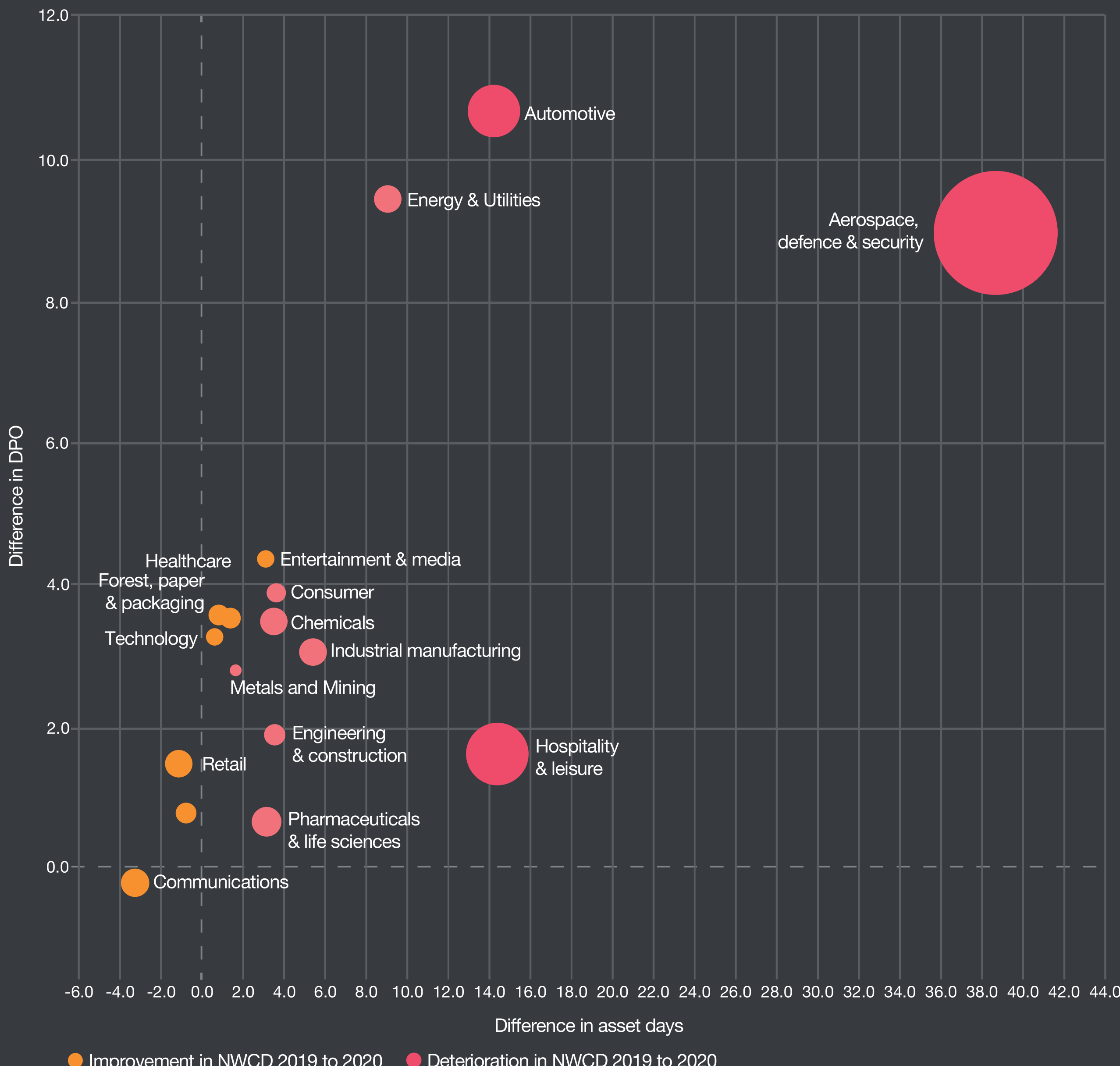
Of the sectors experiencing a decline in NWC days, all but one (Metals & Mining) also saw a deterioration in ROIC. As companies transition from recovery back to growth, it's important to ensure that this growth generates value. Working capital is a key driver of capital efficiency, and our analysis indicates that improving working capital can playing a key role in strengthening returns across sectors.

Figure 9: Change in NWC days and change in ROIC from 2019 to 2020



14-AtchB-21

Figure 10: Asset days / DPO days



Note: size of bubble represents the scale of the absolute YoY change in NWCD

How we can help

We help our clients to:

- Identify and realise cash and cost benefits across the end-to-end value chain
- Improve operational processes that underpin the working capital cycle
- Implement digital working capital solutions and data analytics
- Achieve cash conservation in crisis situations
- Create a 'cash culture' and upskill the organisation through our working capital academy
- Roll out trade and supply chain financing solutions
- Create short term cash flow forecasting and related action plans
- Stand up surge teams and resolve backlogs

Where and how we could help you to release cash from Working Capital

Accounts receivable

- Tailored, proactive collections
- Credit risk policies
- Aligned and optimised customer terms
- Billing timeliness & quality
- Contract & milestone management
- Systematic dispute resolution
- Dispute root cause elimination
- "Surge" operational bandwidth
- Negotiation strategy and support

Inventory

- Lean & agile supply chain strategies
- Global coordination
- Forecasting techniques
- Production planning
- Inventory tracking
- Balancing cost, cash and service level considerations
- Inventory parameters & controls defining target stock

Accounts payable

- Consolidated spending
- Increasing control with centre led procurement
- Helping avoid leakage with purchasing channels
- Payment terms
- Supply chain finance benefits assessment & implementation
- Helping eradicate early payments
- Payment methods
- Negotiation strategy and support

Authors

Daniel Windaus
Partner, PwC UK
T: +44 7725 633420
E: daniel.windaus@pwc.com

Andrew Brady
Working Capital, PwC UK
T: +44 7483 417068
E: andrew.brady@pwc.com

Contributions from:

Mark Anderson
Partner, Supply Chain Resilience Leader
T: +44 7770 921256
E: mark.r.anderson@pwc.com

Emma Tyler
Supply Chain and Third Party Risk and Resilience,
T: +44 7595 611480
E: emma.tyler@pwc.com

Contacts

Canada
Joe Rafuse
E: joe.rafuse@pwc.com

Denmark
Rene Brandt Jensen
E: rene.brandt.jensen@dk.pwc.com

Finland
Michael Hardy
E: michael.hardy@fi.pwc.com

France
Arthur Wastyn
E: arthur.wastyn@pwc.com

Germany and Austria
Rob Kortman
E: rob.kortman@pwc.com

Hong Kong & China
Peter Greaves
E: peter.greaves@hk.pwc.com

India
Neeta Phatarphekar
E: neeta.phatarphekar@pwc.com

Ireland
Declan McDonald
E: declan.mcdonald@ie.pwc.com

Italy
Paolo Menafoglio
E: paolo.menafoglio@pwc.com

Japan
Yusuke Onishi
E: yusuke.onishi@pwc.com

Malaysia/Vietnam
Ganesh Gunaratnam
E: ganesh.gunaratnam@pwc.com

Middle East
Mihir Bhatt
E: mihir.bhatt@pwc.com

Poland
Pawel Dżurak
E: pawel.dzurak@pl.pwc.com

Russia & CIS
Vadim Khrapoun
E: vadim.khrapoun@ru.pwc.com

Spain
Will Extra
E: william.extra@pwc.com

Switzerland
Benjamin Rutz
E: benjamin.rutz@ch.pwc.com

The Netherlands
Danny Siemes
danny.siemes@pwc.com

UK
Daniel Windaus
E: daniel.windaus@pwc.com

Stephen Tebbett
E: stephen.tebbett@pwc.com

USA
Rob Vettoretti
E: r.vettoretti@pwc.com

pwc.co.uk/services/business-restructuring

#ActNowToRecover
#ActNowToGrow

At PwC, our purpose is to build trust in society and solve important problems. PwC is a network of firms in 155 countries with over 284,000 people who are committed to delivering quality in assurance, advisory and tax services. Find out more and tell us what matters to you by visiting us at www.pwc.com/uk.

This content is for general information purposes only, and should not be used as a substitute for consultation with professional advisors.

SPS Design RITM6471222 (11/21).

PACIFIC GAS AND ELECTRIC COMPANY

CHAPTER 14

ATTACHMENT C

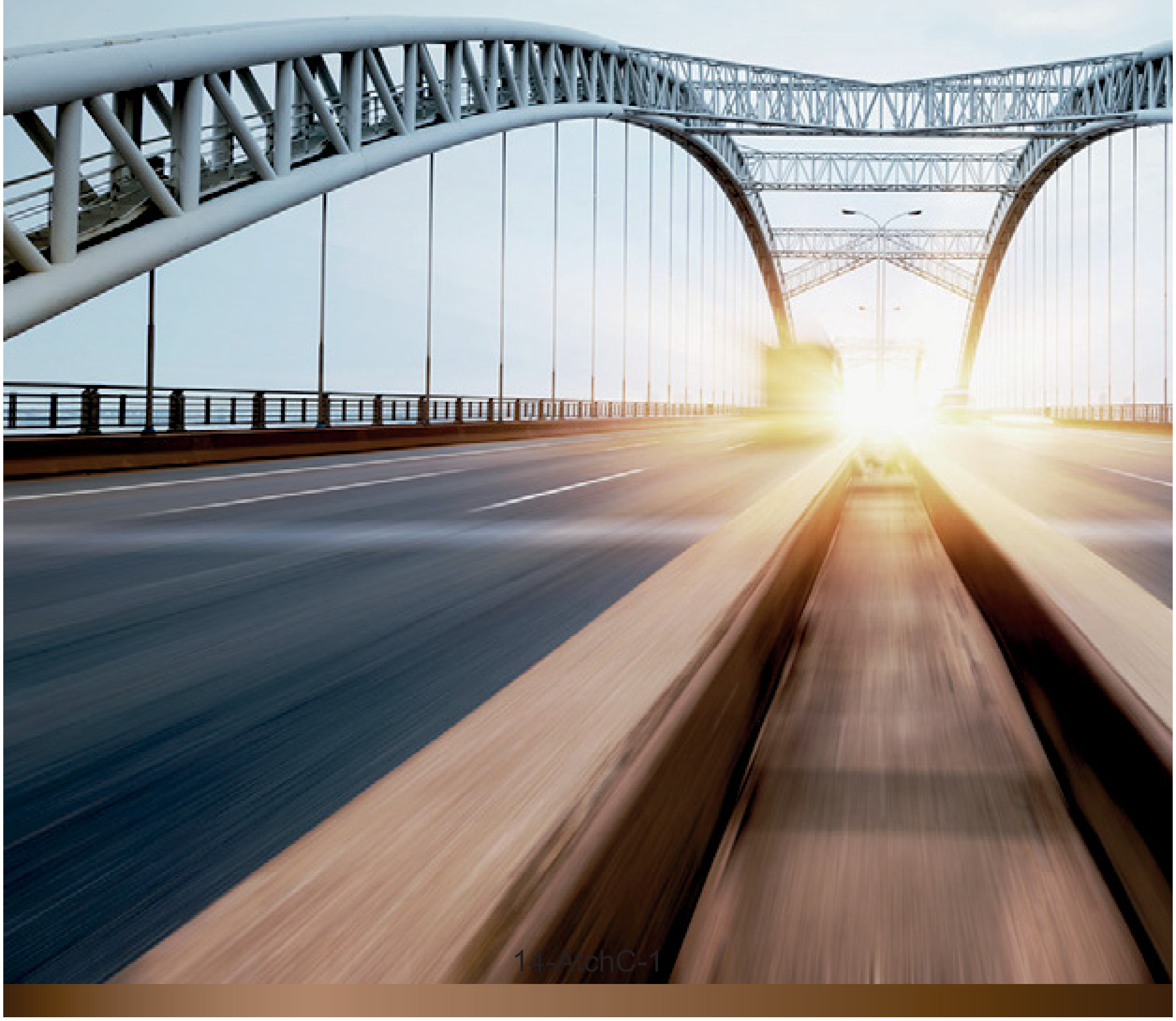
J.P. MORGAN WORKING CAPITAL INDEX 2021

J.P.Morgan

(PG&E-23)

J.P. Morgan Working Capital Index 2021

Helping companies benchmark for success



14-AtchC-1

Table of contents

1 Introduction

This edition of the Working Capital Index report captures the working capital trends of 2020 – a year marked by the onset of the pandemic and the recovery outlook across industries that today continues to unfold and where its full impact on the global economy and business landscape will likely not be known until years from now.

Despite vaccination programs being rolled out globally, many countries are still experiencing new waves of infections, making it difficult to predict how much longer the pandemic will last, or when a full recovery will happen and how that might play out.

For corporates, the key to growth during this period is the strategic shift from capital preservation to capital deployment, where efficient working capital management will play a critical role in sourcing for capital to fund business and expansion opportunities.

Through insights derived from the analysis of working capital metrics, this report aims to help finance practitioners track the working capital trends and guide their initiatives to enhance their working capital management as they prepare for recovery in 2021.

In this issue, we will:

- ➔ Examine the performance of Working Capital Index, Cash Index and Cash Conversion Cycles (CCC) of the S&P 1500 companies in the past year
- ➔ Provide industry insights and assess the impact of pandemic on working capital
- ➔ Analyze the road to recovery and risks by industry

Calculation Methodology

There are three sets of data points analyzed in this report:

I. The **Working Capital Index** tracks the average net working capital/sales values across the S&P 1500 companies and is calculated as follows:

$$\text{Average NWC} = \frac{\sum_{k=1}^{n} \textit{Net Working Capital}_k / \textit{Sales}_k}{\text{n}}$$

II. The **Cash Index** tracks the average cash/sales values across the S&P 1500 companies and is calculated as follows:

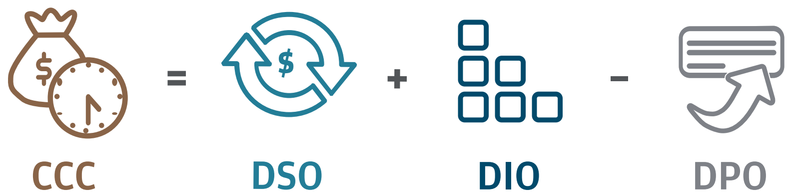
$$\text{Average Cash} = \frac{\sum_{k=1}^{n} \textit{Cash}_k / \textit{Sales}_k}{\text{n}}$$

where:
Net Working Capital = Trade Receivables + Inventory – Trade Payables
n = total number of companies

We have established the base levels of 100 for both the Working Capital Index and the Cash Index, using 2011 as the base year.

III. The **Cash Conversion Cycle (CCC)** is the number of days it takes to convert inventory purchases into cash flows from sales. The CCC is a metric that helps quantify the working capital efficiency of a company and is derived from three different components:

- ➔ Days Sales Outstanding (DSO) or the number of days taken to collect cash from customers
- ➔ Days Inventory Outstanding (DIO) or the number of days the company holds its inventory before selling it
- ➔ Days Payable Outstanding (DPO) or the number of days from the time a company procures raw materials to payment to suppliers



Companies can improve their working capital by effectively managing the individual components of their CCC via reducing inventory levels (decreasing DIO), extending payment terms with suppliers (increasing DPO) and speeding up collections from customers (shortening DSO). As a general rule, the lower the CCC, the better the working capital efficiency.

Note:

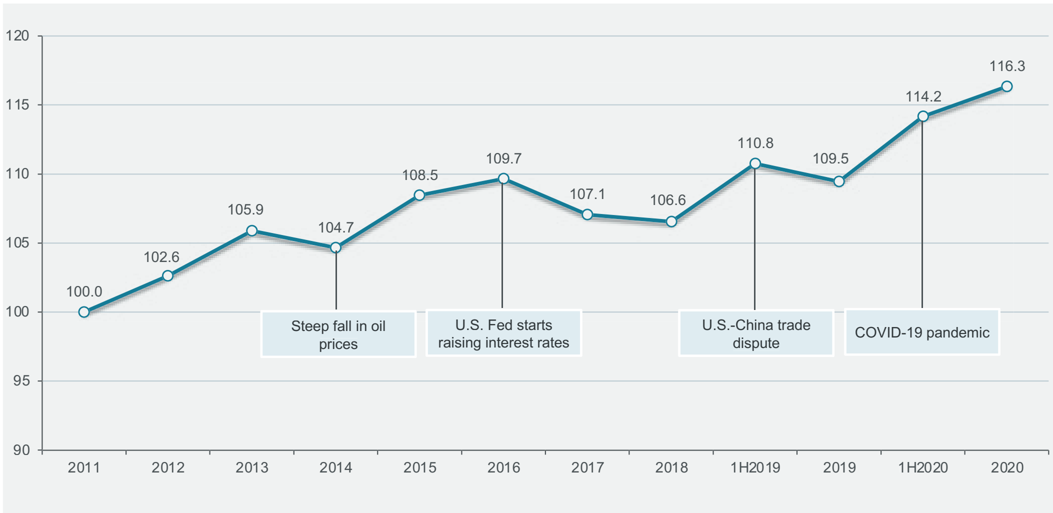
To avoid the distortion of data, financial services and real estate firms in the S&P 1500 were excluded from the calculations due to their distinct business models and unique working capital metrics in comparison to other industries. Companies with high volatility in working capital and those with incomplete data were also removed, bringing the total number of companies used for this analysis to over 900.

All numbered data have been gathered from Capital IQ for the purpose of calculations.

The trends extracted from our analysis were validated against insights from J.P. Morgan's research team.

2 Key Findings

I. Working Capital Index rose to highest level in a decade



Source: Capital IQ

In 2020, the Working Capital Index rose to its highest level in 10 years, as the widespread lockdowns that impacted supply chains as a result of the pandemic crisis, combined with the stalling of demand for products and services across multiple industries as the global economy went into recession, left corporates with high levels of excess inventories. The situation was exacerbated as companies stocked up on inventories to mitigate further supply chain disruptions.

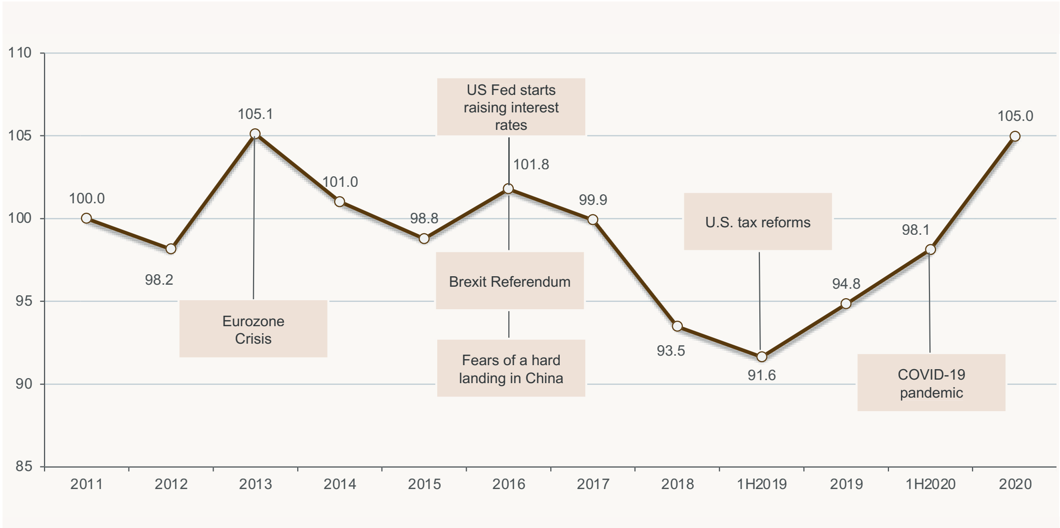
As business sentiment recovered towards the end of the year, sales in some industries improved and receivables levels subsequently rose, further contributing to the increase in working capital levels.

With the global economy expected to recover this year, working capital levels in 2021 will likely trend lower as consumer confidence rebounds and demand for goods and services returns.

Takeaway:

Treasurers should continue to focus on enhancing their working capital management. Significant amounts of liquidity currently trapped in working capital if released in a timely manner can provide the much-needed capital to fund future growth.

II. Cash index rose significantly on fortified liquidity buffers



Source: Capital IQ

The Cash Index also rose in 2020 to levels not seen in seven years as corporates turned to fund-raising initiatives and cash preservation measures to shore up their liquidity buffers amid the pandemic.

Cash preservation initiatives employed included putting a pause on share repurchases, cutting back capital expenditure and reducing external spending. The record low interest rate environment coupled with the massive stimulus from the U.S. government further made it easier for companies to boost their cash holdings,

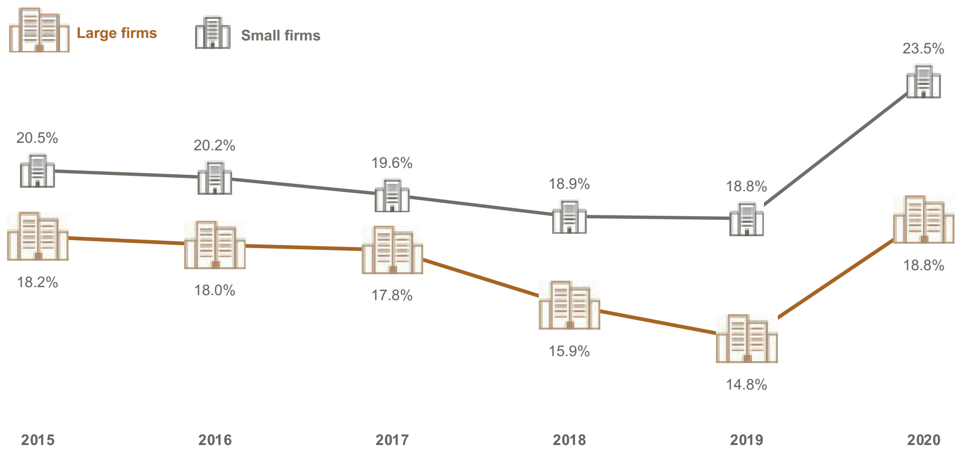
With a recovery taking shape in 2021, we expect corporates to start deploying the excess cash through capital investments, share buybacks, dividends payout, debt repayments or M&As, reducing their cash holdings.

Takeaway:

As corporates prepare for a recovery in their businesses, treasurers should revisit their cash management strategies and shift focus from cash preservation to cash deployment to support the business growth.

III. Widening gap in cash levels between small and big companies

Cash-to-Sales ratio for big companies and small companies



Source: Capital IQ

Note:

Historical ratios restated according to latest S&P 1500 constituents as of 2020. Values for big companies are derived by calculating the averages across the top 50 percent of companies (by revenue) of every industry. For small companies, the value is calculated using the averages of the bottom 50 percent of companies (by revenue) across each industry.

The pandemic crisis posed unique challenges in the ability to procure funding, resulting in a widening gap in cash levels between small and big companies.

Small companies generally maintain higher cash levels than their larger counterparts, as bigger companies tend to have more efficient cash management practices and better access to external capital. During the pandemic, the propensity for lenders to provide capital to small companies relative to big companies reduced, prompting smaller companies to beef up their cash buffers.

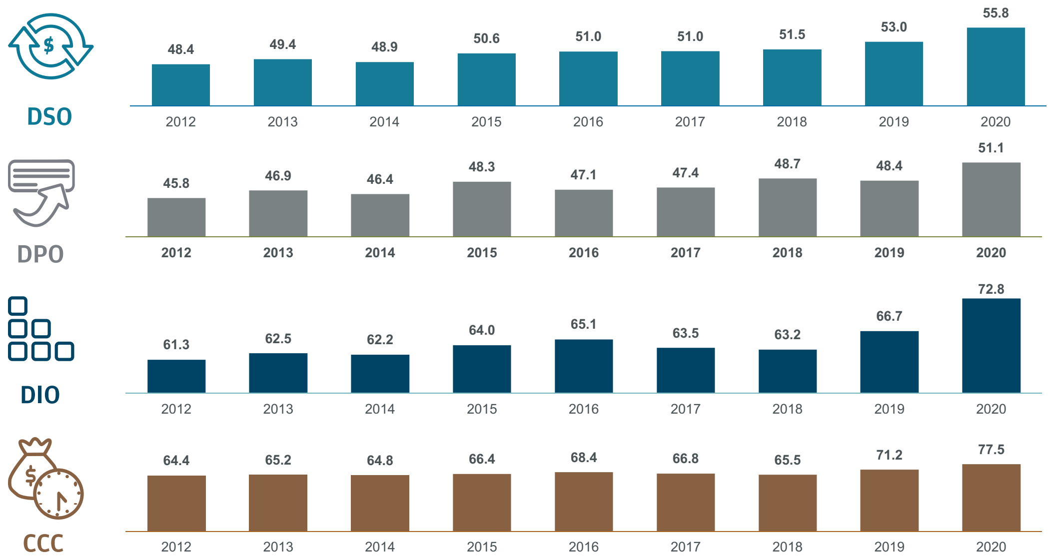
For this reason, 2020 saw an increase of 4.7 percent in cash levels for small companies vis-a-vis a 4.0 percent rise for their bigger counterparts.

Takeaway:

Corporates should assess and create cash management strategies best suited for them, keeping the balance between managing the risks arising from the pandemic crisis and supporting business growth as recovery takes shape.

IV. Cash Conversion Cycle lengthened the most in nine years

Average working capital performance parameters across the S&P 1500 companies 2012-2020 (in average number of days)



Source: Capital IQ

The Cash Conversion Cycle (CCC) of the S&P 1500 companies lengthened by 6.3 days in 2020, representing the biggest increase in nine years, largely due to a rise in inventory levels.

Weakened demand and supply chain disruptions resulted in the inventory buildup, prompting the days inventory outstanding (DIO) to reach a new high where companies were carrying inventories for 6.1 more days on average.

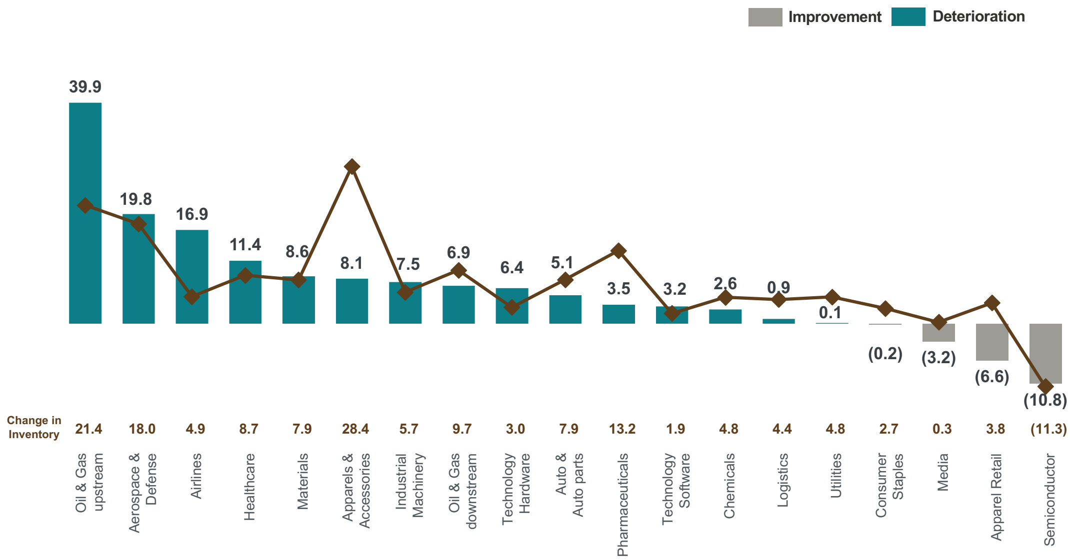
The days payable outstanding (DPO) and days sales outstanding (DSO) also showed sharp increases last year as some companies extended payment terms with their suppliers, customers and leveraged solutions like supply chain finance to manage working capital challenges.

Takeaway:

The pandemic exposed the vulnerabilities of global supply chains, where companies are now focused on reviewing their end-to-end supply chains. By understanding the inherent risks, they need to develop sustainable action plans to build resiliency in their supply chains that can withstand future shocks and mitigate any negative impact on working capital. In addition, the increased interest from investors and corporates on the importance of environmental, social and governance (ESG) will require treasury and finance teams to focus on digitization and sustainable supply chain solutions.

V. Majority of industries experienced deterioration of CCC

Changes in Cash Conversion Cycle by sector (days) 2019-2020



Source: Capital IQ

In terms of the CCC performance across sectors, 15 of the 19 industries saw deterioration, or longer CCCs, due to accumulated inventories.

Among the industries, the CCC of the oil & gas upstream lengthened the most as inventory piled up as a result of reduced demand for oil. The CCC of the aerospace & defense sector also increased significantly amid cancellations of aircraft orders and a drop in demand for aviation parts.

On the other hand, the semiconductor industry experienced the biggest improvement in their CCC due to leaner inventories as a result of strong demand for data storage firms and personal computer manufacturers with the majority of the global workforce pivoting to remote work arrangements.

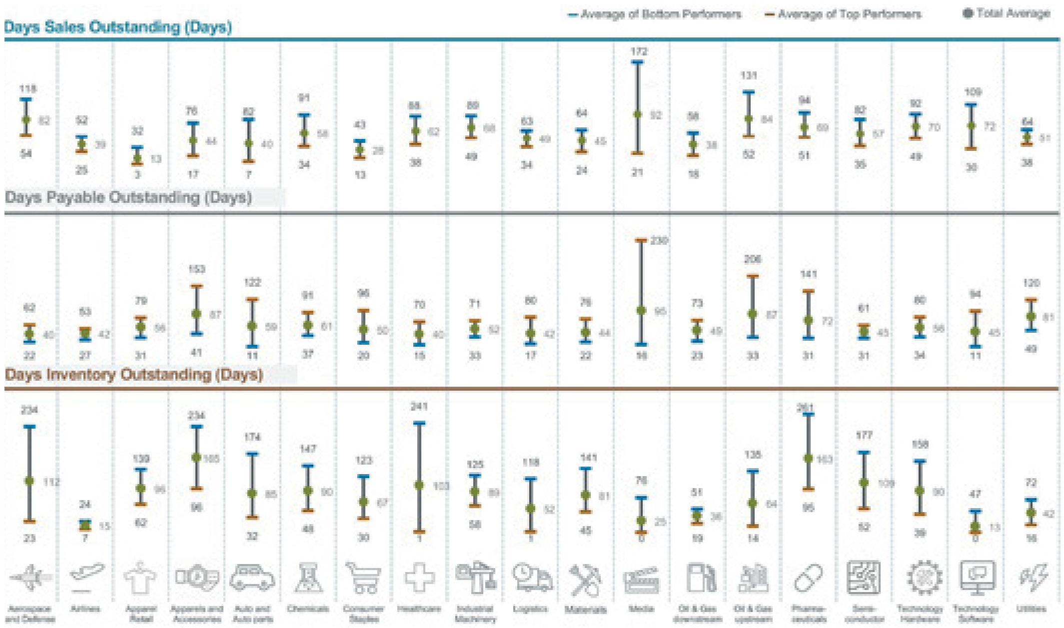
Takeaway:

The pandemic caused significant challenges in working capital management, where some treasurers resorted to tactical short-term measures like delaying their payments to suppliers. For the longer term, treasurers should reassess the levers driving their CCC and devise a more sustainable strategy to manage working capital.

VI. More than $500 billion estimated in potential working capital

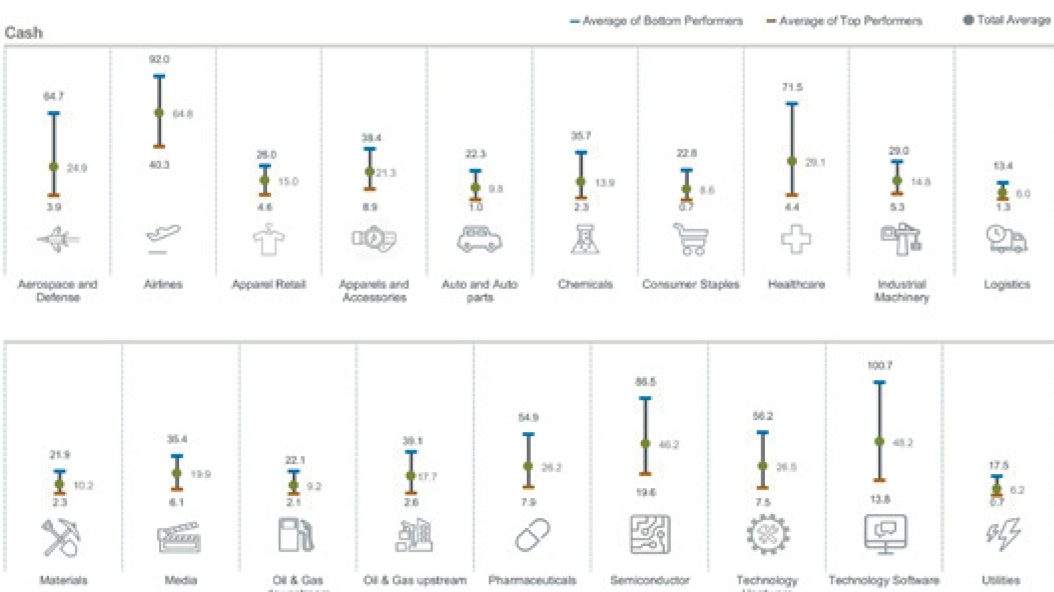
There remains significant amount of liquidity tied up in supply chains across the S&P 1500 companies observed in the DSO, DIO and DPO metrics, as well as the cash levels within industries (see chart below).

Snapshot of the average working capital performances between the top and bottom performers across 19 industries in 2020 (in number of days)



Source: Capital IQ

Snapshot of the average cash levels between top and bottom performers across 19 industries in 2020 (in percentage of revenue)



Source: Capital IQ

Assuming every organization improved its working capital and moved into the next performance quartile[1] in their respective industries across the DSO, the DPO and the DIO metrics, an estimated $507 billion in working capital could have been released as of year-end 2020, up from $497 billion in 2019.

[1] For every working capital parameter we have split the companies within each industry into four performance quartiles (with the first quartile representing the performance of the top 25 percent companies within the industry and the fourth quartile corresponding to the bottom 25 percent). The free cash flow release calculation assumes that a company moves from its existing performance quartile to the next best performance quartile and quartile one companies remain at their current levels

Takeaway:

The increase in trapped working capital implies a widening gap between the leaders and laggards in working capital management. Companies with less efficient working capital management should look at industry best practices and measure their performance on a continuous basis to identify and release some of this trapped capital as they plan for recovery.

3 Post-pandemic Recovery Outlook Across Industries

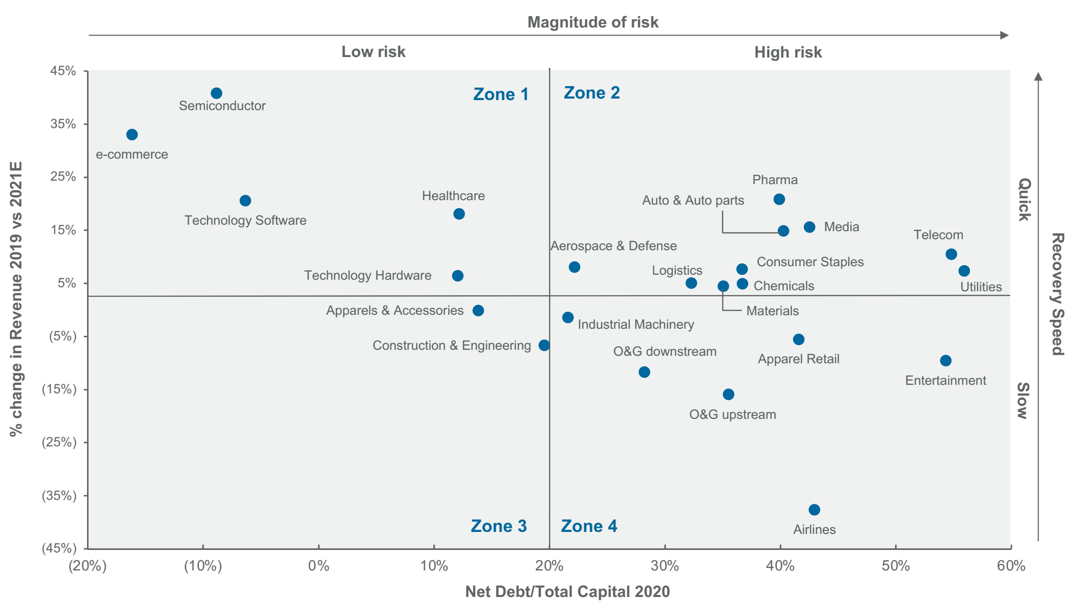
As a result of the pandemic crisis, the global economy in 2020 suffered its worst downturn since World War II, with widespread impact to the business landscape worldwide. However, the extent of the impact varied significantly across industries with sectors like technology and healthcare flourishing and airlines and hospitality severely challenged.

Likewise, the speed of recovery across the industries in 2021 is also expected to be uneven, with growth in some sectors rebounding quickly while others likely to take years before returning to pre-pandemic levels.

To quantify the recovery pace and the inherent risk (measured by debt levels) across industries, we compared the percentage change in revenues of S&P 1500 companies in 2019 (pre-pandemic) versus 2021 estimates[1], against the extent of indebtedness (or net debt to total capital levels) in 2020.

The chart below categorizes findings into four zones:

- ➔ Zone 1: Quick recovery, low risk
- ➔ Zone 2: Quick recovery, medium risk
- ➔ Zone 3: Slow recovery, medium to high risk
- ➔ Zone 4: Slow recovery, very high risk



Source: Capital IQ

[1]2021 Revenue estimates as of March 25, 2021

Industries that lie within **Zone 1**, such as e-commerce, semiconductor and technology software, were either positively or minimally impacted by the pandemic. With low debt levels, these industries are expected to experience revenue growth this year and will have little need to preserve excess cash. They are likely to initiate aggressive cash deployment towards expansionary measures like capital expenditure and M&A to drive growth in the next few years.

Sectors in **Zone 2** like media, auto & auto parts, and consumer staples will also likely see business rebound this year but they have stretched balance sheet positions due to high net debt levels. Companies in this zone should be cautious with their growth plans, and focus on enhancing working capital and liquidity efficiencies to fund expansion from internal sources without impacting their leverage positions.

Industries within **Zone 3** suffered a steep fall in revenues, but their relatively strong balance sheets provide them room to take on further debt. As these industries could experience slower recovery this year, they may have to play a waiting game and continue to focus on building their liquidity reserves to fund growth when the opportunities arise.

Sectors with **Zone 4** – including airlines, oil & gas, and entertainment — were the hardest hit and recovery will take some time. With high leverage levels and having suffered adverse impacts to cash flows and liquidity, these industries will find themselves on the defensive with no room to stretch their balance sheets further. Cash deployment will be subdued and companies in this zone should maintain focus on preserving cash, enhancing liquidity management and generating working capital efficiencies.

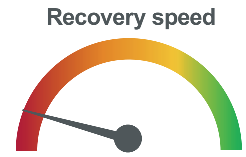
Key industry insights

To illustrate the extent of pandemic impact on different industries, we examined four sectors representing the different zones:

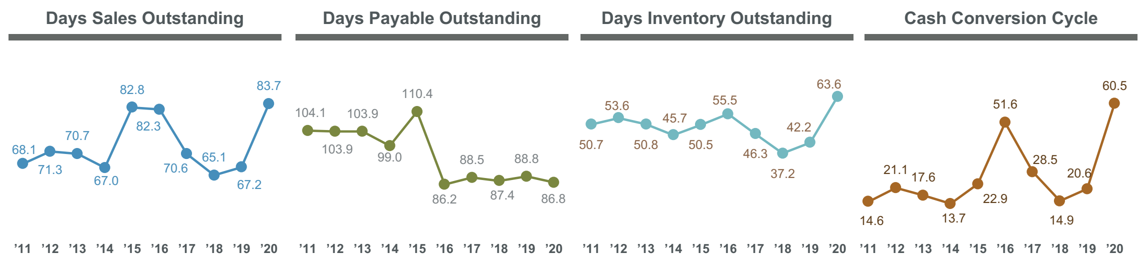
- ➔ Oil & Gas upstream
- ➔ Auto & Auto parts
- ➔ Apparel & Accessories
- ➔ Semiconductor

The analysis also breaks down the working capital parameters into four performance quartiles (with the first quartile representing the performance of the top 25 percent companies within the industry and the fourth quartile corresponding to the bottom 25 percent) to enable finance practitioners to identify industry averages and benchmark their organizations' working capital performances against peers.

I. Oil and Gas upstream



Comparison of working capital parameters within the oil and gas upstream sector 2011-2020 (in average number of days)

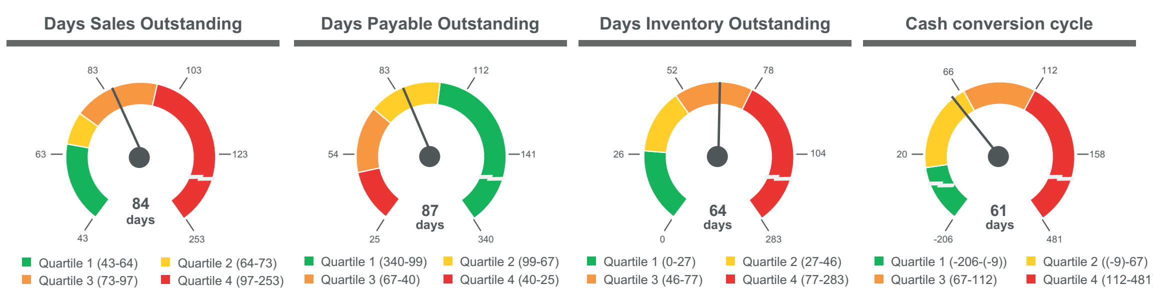


Source: Capital IQ

2020 was a year of disruption for the oil and gas upstream sector with the CCC deteriorating by 40 days. The industry was already experiencing headwinds prior to the pandemic as a result of the global trade tensions and oil price wars between global oil producers. The onset of pandemic caused global demand to slump, driving down oil prices to levels not seen since the aftermath of September 11 terrorist attacks in 2001. The oversupply led to excess oil inventory levels, resulting in a rise of approximately 21 days in DIO on average for the upstream sector.

The companies in the upstream sector faced severe liquidity challenges particularly related to delayed payments and payment defaults by their customers, leading to an average increase of 17 days in DSO.

Working capital parameters within the oil and gas upstream industry 2020 (in average number of days)



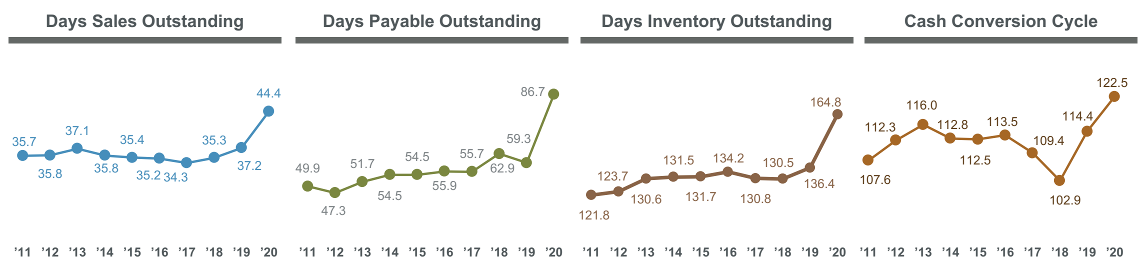
Source: Capital IQ

In 2020, upstream companies took an average of 87 days to pay its suppliers while cash from sales was realized in 84 days. On average, companies maintained 64 days' worth of inventory.

(PG&E-23)

II. Apparel and Accessories

Comparison of working capital parameters within the apparel and accessories sector 2011-2020 (in average number of days)



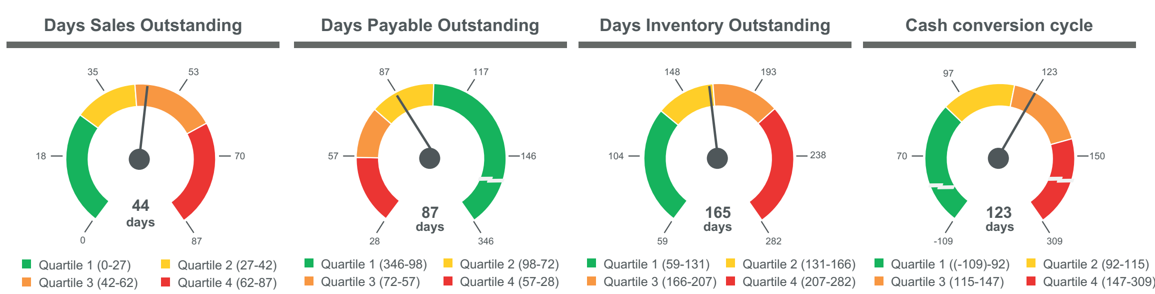
Source: Capital IQ

The apparel and accessories industry experienced one of its most challenging years in recent memory as the widespread lockdowns due to pandemic kept stores shut and disrupted supply chains.

While consumers took to e-commerce platforms for shopping, helping to reduce inventory levels, the industry still saw an average increase of 28 days in DIO from 2019 levels. Delays in payments by customers also led to an increase in the DSO by 7 days on average.

However, a large part of the CCC increase was offset by increase in DPO that rose by 27 days on average as companies delayed their vendor payments or used supply chain financing solutions to manage their liquidity needs.

Working capital parameters within the apparel and accessories industry 2020 (in average number of days)

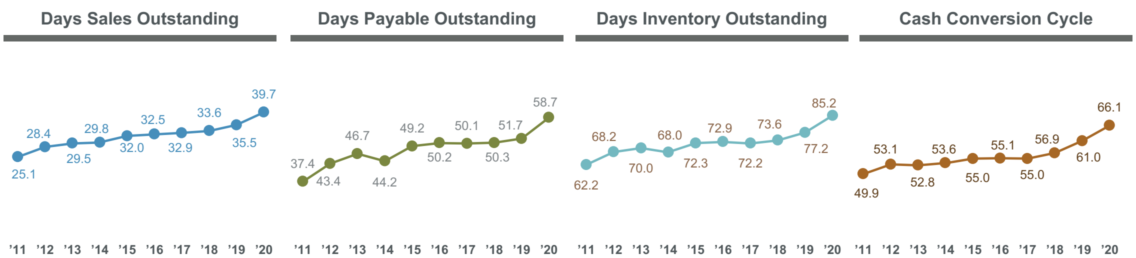


Source: Capital IQ

In 2020, companies within the apparel and accessories industry took an average of 44 days for to turn sales into cash proceeds. The sector held 165 days' worth of inventory, and payments to suppliers were generally made within an average of 87 days.

III. Auto and Auto parts

Comparison of working capital parameters within the auto and auto parts sector 2011-2020 (in average number of days)



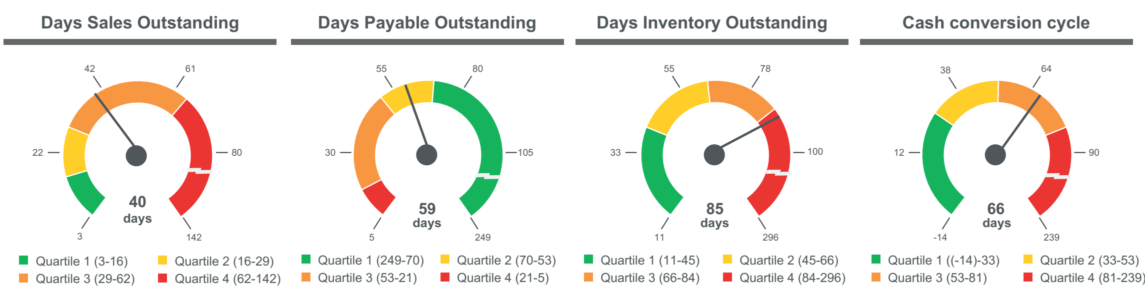
Source: Capital IQ

The auto and auto parts industry was one of the hardest hit sectors at the onset of pandemic as widespread factory closures, slumping car sales and massive layoffs led to supply and demand shocks for both auto suppliers and automakers. Inventory levels rose significantly in the first half of 2020 as demand collapsed.

A rebound in demand in the second half of 2020 helped to reduce inventories from the highs of first half 2020. On average, the DIO rose by 8 days compared to 2019 levels.

The DPO rose by an average of 7 days as companies negotiated for temporary extensions of payments terms with suppliers and service providers in response to the pandemic. The 4 days on average rise in the DSO was reflective of the increase in receivables in the fourth quarter when demand for auto parts rebounded.

Working capital parameters within the auto and auto parts industry 2020 (in average number of days)



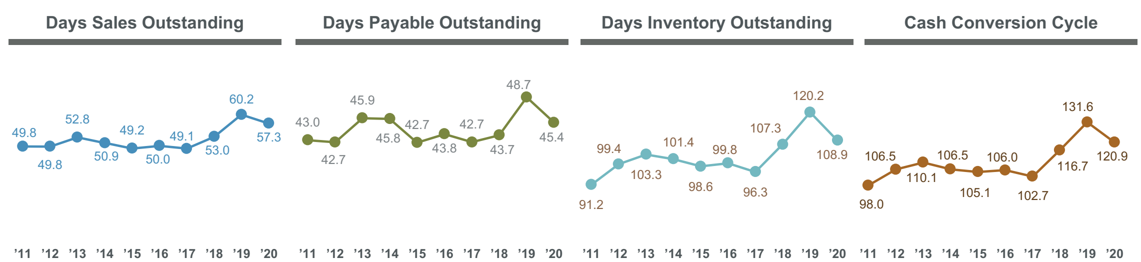
Source: Capital IQ

As of 2020, auto and auto parts companies took an average of 59 days to pay off supplier invoices. They maintained an average of 85 days' worth of inventory and took 40 days to convert sales into cash proceeds.

(PG&E-23)

IV. Semiconductor

Comparison of working capital parameters within the semiconductor sector 2011-2020 (in average number of days)

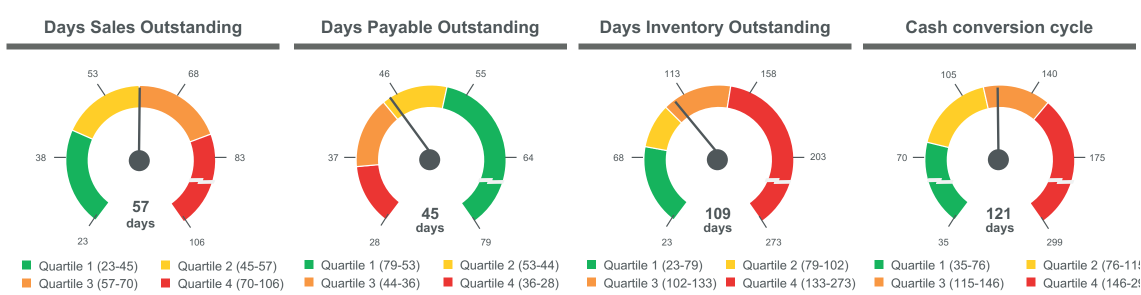


Source: Capital IQ

As majority of the global working population pivoted to remote work arrangements as a result of movement restrictions and lockdowns, the semiconductor industry experienced a surge in demand on the back of strong sales of consumer electronics goods and increased demand for cloud services. Combined with additional factors including the adoption of 5G technologies, resurgence in demand for automobiles towards the end of the year, and an increase in size of orders by customers to build inventory reserves due to supply chain concerns, the semiconductor industry was at the brink of exhausting its manufacturing capacity by the end of 2020. The industry' DIO decreased by approximately 11 days in 2020 as compared to 2019.

High demand for semiconductor-related products also resulted in lower DSO as the firms could bargain for faster collections from their customers. The DSO improvement was however largely offset by a reduction in the DPO as the industry passed on the benefits to their suppliers. Overall, the industry's CCC decreased by an average of 11 days in 2020.

Working capital parameters within the semiconductor industry 2020 (in average number of days)



Source: Capital IQ

In 2020, the semiconductor industry took an average of 45 days to pay off suppliers, maintained 109 days of inventory and took 57 days to turn sales into cash proceeds.

4 Managing Liquidity Risks

A Lesson from History

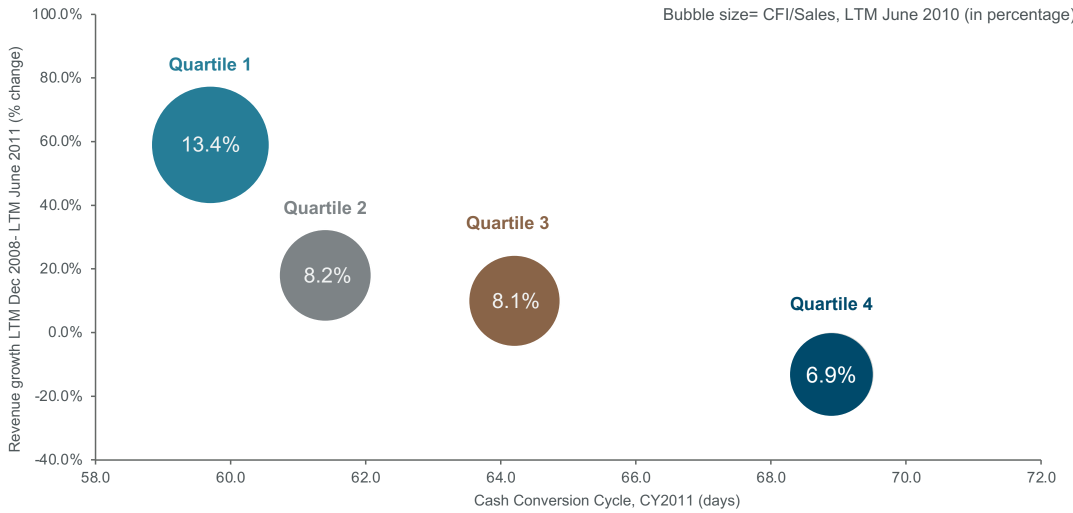
As the focus of businesses turns towards recovery, we wanted to examine past economic downturns of similar magnitude to derive lessons we can apply to the current recovery phase.

Using data from the S&P 1500 companies during the global financial crisis (GFC) of 2008, we calculated the percentage change in their revenue at the height of the crisis (the 12 months ending December 2008) and post recovery from the crisis (12 months ending June 2011). We also calculated their cash flow from investing (CFI) as a percentage of sales from July 2009 to June 2010 – widely viewed as the initial phase of the recovery from the GFC and a period we are using as a benchmark to compare recovery trends in the current environment. Finally, we cross checked the S&P 1500 companies' CCCs in 2011 against growth rates during GFC recovery period.

We observed a strong correlation between the amount companies invested during the early phase of recovery and the pace of rebound in their revenue growth. Also, the companies who invested the most and registered strong revenue growth also displayed low CCC readings (categorized in Quartile 1), reflecting robust working capital efficiencies.

This demonstrates the importance of working capital management during the recovery phase of a crisis in facilitating a rebound; the S&P 1500 companies that were able to manage working capital efficiently could access cheap internal source of funding during recovery phase of the GFC allowing them to quickly deploy more cash towards growth activities.

Correlation between revenue growth and working capital efficiency as well as cash deployment



Source: Capital IQ

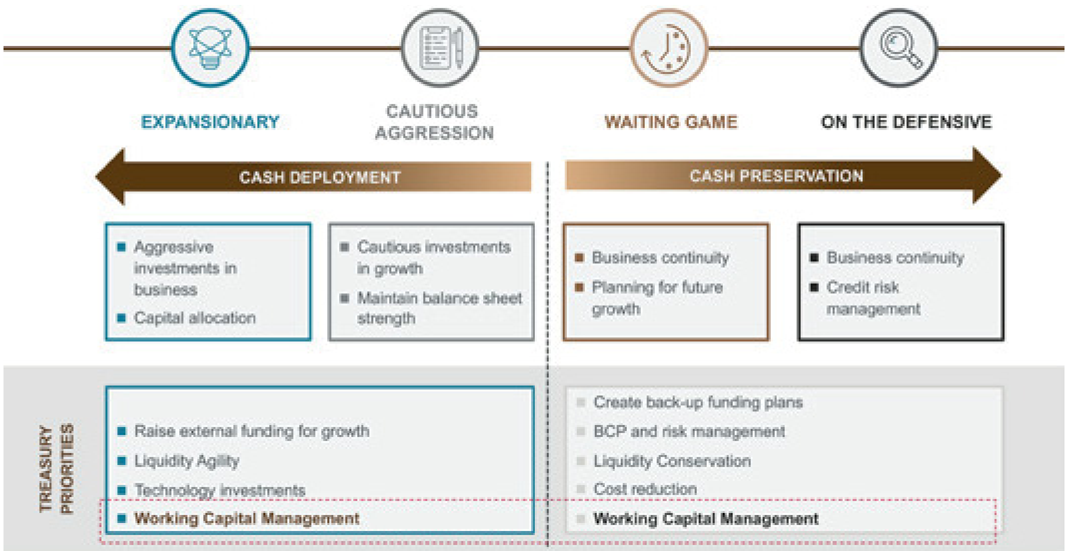
Note:

S&P 1500 companies have been categorized into four quartiles based on their revenue growth, with the first quartile representing the top 25% companies with the highest revenue growth within their industries, while the fourth quartile corresponds to the bottom 25% companies with the lowest revenue growth in their respective sectors.

5 Conclusion

The pandemic has put unprecedented financial pressures on businesses, compelling CFOs and corporate treasurers to re-evaluate their cash and liquidity management to ensure business and operational continuity

Treasurers will continue to play an important role as businesses recover from the pandemic. We highlight four different approaches treasurers can take to navigate the crisis this year, depending on the speed of recovery and the strength of their balance sheets.



Expansionary: Companies with strong balance sheets and are expecting a fast recovery would likely invest aggressively either through organic or inorganic means for growth in 2021. Cheap cost of funding and high cash levels can provide the necessary firepower for these companies to execute their plans. The key priority for treasury in these companies will be to ensure that necessary cash is available at the right place, at right time and in right currency to fund high value transactions.

Cautious aggression: Companies that are expecting quick recovery but have high leverage ratios may have challenges accessing external capital due to limitations to further stretch their balance sheet. Treasurers will need to balance funding growth while ensuring the company does not face liquidity challenges.

Waiting game: Companies with slow expected recovery but with strong balance sheets will likely wait a little longer to invest in the growth. Focus for treasurers in these companies will likely be to continue with cash preservation activities like reduction in capex, M&A activities and discretionary expenses to create reserves for funding growth when the opportunities arise.

On the Defensive: Companies with slow expected recovery and weak balance sheets will be the most at risk of further impacts from the crisis. Conserving liquidity will be the key priority as treasurers look to ensure the company has enough cash until the crisis blows over.

While there are varied paths treasurers will have to take during recovery in 2021, we expect working capital optimization to continue to remain a key priority for treasurers. With ~US$507bn currently trapped in working capital that can potentially be released, it can provide a cheap source of funding to either support the growth for companies experiencing strong recovery or provide the liquidity cushion for businesses waiting to ride out the crisis.

6 Summary of Findings

$507 BILLION

Estimated working capital that can be released across the S&P 1500 companies

Top three industries showing deterioration in CCC in 2020

(Number of days the CCC lengthened by)

16.9
Airlines

19.8
Aerospace & Defense

39.9
Oil & Gas upstream

Top three industries showing improvement in CCC in 2020

(Number of days the CCC shortened by)

10.8
Semiconductor

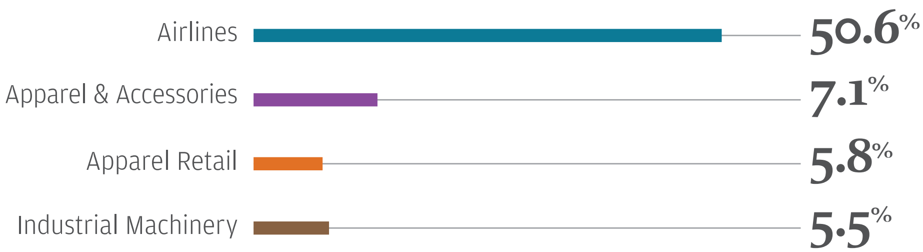
6.6
Apparel Retail

3.2
Media

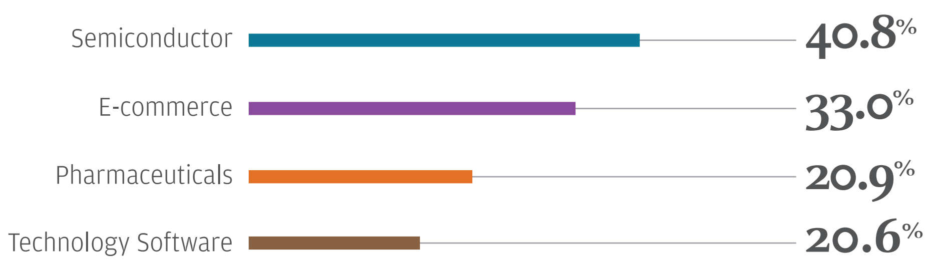
64% **of companies in the S&P 1500**
saw a deterioration in CCC of which:

- **86%** showed a lengthening in DSO
- **87%** experienced an increase in DIO

Top four industries with the highest rise in cash levels in 2020



Top four industries with maximum growth expected during recovery (based on estimates in 2021 revenue)



Growth in revenue during global financial crisis recovery

(December 2008 – June 2011)

58.8%
Companies with top performing CCC

-13.2%
Companies with bottom performing CCC

(PG&E-23)

7 Authors

Gourang Shah
Global head for Treasury and Working Capital Optimization
Wholesale Payments
J.P. Morgan
gourang.shah@jpmorgan.com

Varoon Mandhana
Head of Wholesale Payments Solutions, Asia Pacific
J.P. Morgan
varoon.mandhana@jpmorgan.com

Vikrant Verma
Advisor, Wholesale Payments Solutions, Asia Pacific
J.P. Morgan
vikrant.verma@jpmorgan.com

J.P.Morgan

(PG&E-23)

PACIFIC GAS AND ELECTRIC COMPANY

CHAPTER 15

REBUTTAL TESTIMONY OF

PEI SUE ONG

ELECTRIC AND GAS DISTRIBUTION, ELECTRIC GENERATION, GAS TRANSMISSION AND STORAGE RATE BASE

PACIFIC GAS AND ELECTRIC COMPANY
CHAPTER 15
REBUTTAL TESTIMONY OF
PEI SUE ONG
ELECTRIC AND GAS DISTRIBUTION, ELECTRIC GENERATION, GAS TRANSMISSION AND STORAGE RATE BASE

TABLE OF CONTENTS

PACIFIC GAS AND ELECTRIC COMPANY
CHAPTER 15
REBUTTAL TESTIMONY OF
PEI SUE ONG
ELECTRIC AND GAS DISTRIBUTION, ELECTRIC GENERATION, GAS TRANSMISSION AND STORAGE RATE BASE

A. Introduction

Q 1 Please state your name and the purpose of this rebuttal testimony.

A 1 My name is Pei Sue Ong. This testimony responds to the direct testimony of the Public Advocates Office at the California Public Utilities Commission (Cal Advocates or CA).[1] I summarize parties' positions in Section B below.

B. Summary of Issues

Q 2 Please provide a summary of parties' policy positions to which you will be responding.

A 2 This testimony responds to Cal Advocates' recommendation to remove from rate base and therefore from PG&E's 2023-2026 capital revenue requirements, the following recorded and/or forecast capital expenditures: (i) Community Rebuild Program costs tracked in the Catastrophic Events Memorandum Account (CEMA) and (ii) wildfire mitigation costs tracked in the Wildfire Mitigation Plan Memorandum Account (WMPMA). Each issue is discussed in Section C below.

---

[1] CA-05.

C. PG&E's Response to Parties' Policy Positions

1. Recorded and/or Forecast Capital Expenditures for the Community Rebuild Program tracked in the Catastrophic Events Memorandum Account and Wildfire Mitigation Costs tracked in the Wildfire Mitigation Plan Memorandum Account.

Q 3 What is Cal Advocates' recommendation for capital costs related to the Community Rebuild Program?[2]

A 3 Cal Advocates recommends the removal of all recorded and forecast capital expenditures related to the Community Rebuild Program.[3]

Q 4 What is Cal Advocates' main reason for requesting such costs to be removed?

A 4 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. Cal Advocates contends that Community Rebuild cost can only be recovered through a CEMA-related application and that Community Rebuild costs should not be included in GRC rates prior to the Commission's determination of their reasonableness through a separate application.[4]

Q 5 Does Cal Advocates propose to remove other forecast costs from the GRC because the revenue requirements for some years of those costs are recorded in a memorandum account?

A 5 Yes, Cal Advocates is also recommending the removal of the 2021 and 2022 forecast capital expenditures for the WMPMA until the Commission determines the reasonableness of the recorded WMPMA expenditures through a separate application.[5]

Q 6 What is the purpose of the WMPMA?

A 6 The purpose of the WMPMA is to record incremental costs incurred to implement an approved Wildfire Mitigation Plan (WMP) that are not

---

2 As described in Exhibit (PG&E-4), Ch. 23, the Community Rebuild Program was initiated to rebuild PG&E's electric and gas system infrastructure following the 2018 Camp Fire.

3 CA-05, p. 54, line 23 to p. 55, line 6.

4 CA-05, p. 5, lines 22-27, and p. 54 lines 7-9.

5 CA-05, p.19, lines 1-20.

otherwise recovered in PG&E's adopted revenue requirements. Such costs may include expense and revenue requirements related to capital expenditures for activities including, but not limited to, operational practices, inspection programs, system hardening, enhanced vegetation management, enhanced situational awareness, public safety power shutoffs, and alternative technologies.[6]

Q 7 What is PG&E's proposed treatment of capital costs associated with work on an approved WMP and the Community Rebuild Program in the GRC?

A 7 PG&E has proposed to include in its 2023-2026 capital revenue requirements, the recorded and forecast capital costs associated with activities that are being recorded to memorandum accounts through the year 2022. PG&E is not precluded from including in rate base, capital costs tracked in memorandum accounts for purposes of computing its test year and post test-year revenue requirements in a GRC. The purpose of a memorandum account is to provide a mechanism to record and recover incremental expenses and capital revenue requirements incurred between GRCs to make the utility whole for the incremental costs incurred during that interim period to avoid the prohibition against retroactive ratemaking.[7] PG&E disagrees that capital costs tracked in memorandum accounts must be assessed for incrementality or reasonableness review before plant is put into rate base in a GRC. To the contrary, under the principles of forecast ratemaking, PG&E should be encouraged to put forward recorded plant and known future costs associated with activities that are 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. There is no reasonable dispute that these recorded plant costs are currently used and useful in providing an essential utility service to PG&E's customers. The recorded plant and forecasts PG&E included in this GRC are subject to the Commission's and parties' review and determination of reasonableness.

---

6 PG&E Electric Preliminary Statement Part HX, WMPMA, paragraph 1.

7 Res.E-3238 (July 24, 1991), p. 4, Finding No. 1.

Further, when a utility seeks recovery of incremental costs recorded to a memorandum or balancing account through a separate application, it is the utility's burden of proof to demonstrate that the costs are incremental and not duplicative of revenues authorized for the utility's base funding, as provided in a GRC. PG&E's recorded plant and forecasts in this GRC that relate to activities presently tracked in memorandum accounts are consistent with this principle.

Q 8 How would the removal of such expenditures from the GRC impact PG&E's financial health?

A 8 The impacts of deferral of cost recovery on the utility's financial health are addressed in Exhibit (PG&E-14), Chapter 3.

Q 9 Does this conclude your rebuttal testimony?

A 9 Yes, it does.

PACIFIC GAS AND ELECTRIC COMPANY
CHAPTER 16
OTHER OPERATING REVENUES

THIS CHAPTER HAS NO REBUTTAL

PACIFIC GAS AND ELECTRIC COMPANY

CHAPTER 17

CALCULATION OF REVENUE REQUIREMENT

THIS CHAPTER HAS NO REBUTTAL

PACIFIC GAS AND ELECTRIC COMPANY

CHAPTER 17S

APPENDIX A

CONFIDENTIALITY DECLARATION

THIS APPENDIX HAS NO REBUTTAL

PACIFIC GAS AND ELECTRIC COMPANY

APPENDIX B

CONFIDENTIALITY DECLARATIONS

THIS APPENDIX HAS NO REBUTTAL

PACIFIC GAS AND ELECTRIC COMPANY

APPENDIX C

DATA RESPONSES INCLUDED AS APPENDIX C TO PG&E'S REBUTTAL TESTIMONY

Pacific Gas and Electric Company
2023 General Rate Case
A.21-06-021
Results of Operations - Exhibit (PG&E-23)
Data Responses Included as Appendix C to PG&E's Rebuttal Testimony

Line No.	Chapter	Data Request Number	Topic
1	12	GRC-2023-PhI_DR_PGE_CalAdvocates005-Q01-05	Depreciation Study
2	12	GRC-2023-PhI_DR_PGE_ TURN006-Q01-04, 07-10, 15, 17	Depreciation Study
3	14	GRC-2023-PhI_DR_CalAdvocates_045-Q006	Working Cash
4	14	GRC-2023-PhI_DR_CalAdvocates_083-Q001	Working Cash
5	14	GRC-2023-PhI_DR_CalAdvocates_112-Q016	Working Cash
6	14	GRC-2023-PhI_DR_TURN_151-Q010	Working Cash
7	14	GRC-2023-PhI_DR_CalAdvocates_015-Q004	Working Cash
8	14	GRC-2023-PhI_DR_CalAdvocates_068-Q006	Working Cash
9	14	GRC-2023-PhI_DR_CalAdvocates_068-Q007	Working Cash
10	14	GRC-2023-PhI_DR_CalAdvocates_068-Q008	Working Cash
11	14	GRC-2023-PhI_DR_CalAdvocates_068-Q009	Working Cash
12	14	GRC-2023-PhI_DR_TURN_061-Q005	Working Cash
13	14	GRC-2023-PhI_DR_TURN_061-Q007	Working Cash
14	14	GRC-2023-PhI_DR_TURN_151-Q008	Working Cash
15	14	GRC-2023-PhI_DR_TURN_061-Q003	Working Cash
16	14	GRC-2023-PhI_DR_TURN_061-Q004	Working Cash
17	14	GRC-2023-PhI_DR_TURN_151-Q002	Working Cash
18	14	GRC-2023-PhI_DR_TURN_151-Q003	Working Cash
19	14	GRC-2023-PhI_DR_TURN_151-Q005	Working Cash
20	14	GRC-2023-PhI_DR_PGE_CalAdvocates003-Q001, 003, 004, 005, 007-009	Working Cash
21	11	GRC-2023-PhI_DR_CalAdvocates_016-Q01 (f, g)	Depreciation Expense and Reserve
22	11	GRC-2023-PhI_DR_CalAdvocates_052-Q08	Depreciation Expense and Reserve
23	11	GRC-2023-PhI_DR_CalAdvocates_083-Q06	Depreciation Expense and Reserve
24	11	GRC-2023-PhI_DR_CalAdvocates_083-Q07	Depreciation Expense and Reserve
25	11	GRC-2023-PhI_DR_CalAdvocates_083-Q08	Depreciation Expense and Reserve
26	11	GRC-2023-PhI_DR_CalAdvocates_083-Q09	Depreciation Expense and Reserve
27	11	GRC-2023-PhI_DR_CalAdvocates_083-Q10	Depreciation Expense and Reserve
28	11	GRC-2023-PhI_DR_CalAdvocates_083-Q12	Depreciation Expense and Reserve
29	11	GRC-2023-PhI_DR_CalAdvocates_113-Q04	Depreciation Expense and Reserve
30	11	GRC-2023-PhI_DR_CalAdvocates_126-Q01	Depreciation Expense and Reserve
31	11	GRC-2023-PhI_DR_CalAdvocates_236-Q01	Depreciation Expense and Reserve
32	11	GRC-2023-PhI_DR_CalAdvocates_236-Q02	Depreciation Expense and Reserve
33	11	GRC-2023-PhI_DR_CalAdvocates_237-Q01	Depreciation Expense and Reserve
34	11	GRC-2023-PhI_DR_CalAdvocates_237-Q02	Depreciation Expense and Reserve

PUBLIC ADVOCATES OFFICE (Cal Advocates)
DATA RESPONSE
Pacific Gas & Electric Company Test Year 2023 General Rate Case
A.21-06-021

Date: 24 June 2022

Origination Date: 17 June 2022

Response Due: 27 June 2022

To: Hannah Keller, PG&E Discovery Manager
HXKY@pge.com
cc: GRC@pge.com

GRC 2023 Coordinators:
Rachel Keller, Victoria Anes, Gissell Morales,
Maria Osorio, and Sharh Phung

From: Tamera Godfrey, Project Coordinator
Public Advocates Office
505 Van Ness Avenue, Room 4104
San Francisco, CA 94102 tamera.godfrey@cpuc.ca.gov

Data Request No: GRC-2023-PhI_DR_PGE_CalAdvocates005

GENERAL OBJECTIONS

Cal Advocates objects to each data request to the extent that it mischaracterizes Cal Advocates' opening testimony.

Cal Advocates objects to each data request to the extent that it is overly broad, unduly burdensome, or not reasonably calculated to lead to the discovery of admissible evidence.

Cal Advocates objects to each instruction and data request as overly broad and unduly burdensome to the extent that it seeks documents or information that PG&E will possess when it receives Cal Advocates' opening testimony. Responding to such requests would be oppressive, unduly burdensome, and unnecessarily expensive, and the burden of responding to such requests is substantially the same or less for PG&E as for Cal Advocates. All such documents and information will not be produced.

Cal Advocates objects to each instruction and data request to the extent that it seeks information or documents protected from disclosure by the attorney-client privilege, attorney work product doctrine, or any other applicable privilege.

PG&E Question 1:

In reference to the statewide California goal established to be carbon neutral by 2045 (as discussed on page 11-12 of Exhibit (PG&E-10)):

a. Does Public Advocates believe that this goal affects PG&E's operation of its gas assets?

b. If the response to part (a) is yes, please explain how Public Advocates believes the carbon neutrality by 2045 goal will affect PG&E's assets and how Public Advocates incorporated these expectations into Public Advocates' recommended depreciation rates.

c. If the response to part (a) is no, please explain why Public Advocates believes a significant gas emissions reduction goal will have no effect on gas system assets.

Public Advocates Office Response to Question 1:

a. Cal Advocates notes that the reference to "PG&E's operation of its gas assets" is vague and overbroad, as PG&E's gas operations is extensive and includes non-Core gas delivery and facilitation activities that may not directly impact the company's goal towards carbon neutrality, or even exist, by 2045. Further, the statewide goal to be carbon neutral by 2045 is too far removed from the 2023 GRC cycle time period.
b. Not applicable.
c. The question calls for speculation at this point in time (2022) to reach a conclusion about what may happen by 2045.

Response prepared by Truman Burns.

PG&E Question 2:

All else equal, does Public Advocates believe that state goals for carbon neutrality are likely to result in service lives for gas mains being shorter, longer or the same as in the past?

Public Advocates Office Response to Question 2:

See Cal Advocates' response to Question 1, c.

Response prepared by Truman Burns.

PG&E Question 3:

All else equal, does Public Advocates believe that state goals for carbon neutrality would result in service lives for gas services being shorter, longer or the same as in the past?

Public Advocates Office Response to Question 3:

See Cal Advocates' response to Question 1, c.

Response prepared by Truman Burns.

PG&E Question 4:

All else equal, does Public Advocates believe that state goals for carbon neutrality are likely to result in depreciation being higher, lower or the same as in the past?

Public Advocates Office Response to Question 4:

See Cal Advocates' response to Question 1, c.

Response prepared by Truman Burns.

PG&E Question 5:

The Public Advocates' recommended net salvage percentages are not consistent between Table 15-2 and 15-5. Please confirm that the net salvage percentages included in Table 15-5 are the actual Public Advocates Recommended net salvage percentages.

Public Advocates Office Response to Question 5:

Confirmed.

Response prepared by Truman Burns.

PG&E Question 6:

Please confirm that under the “Net Salvage Rates” section of Table 15-3, the account number should be “376” and not “375” as is displayed in the table.

Public Advocates Office Response to Question 6:

Confirmed.

Response prepared by Truman Burns.

PACIFIC GAS AND ELECTRIC COMPANY
2023 General Rate Case Phase I
Application 21-06-021
Data Request

To:	David J. Garrett (Q1 through Q4, Q9 through Q10, Q12 through Q16) Robert Finkelstein (Q5 through Q8, Q11, Q17 and Q18)
PG&E Data Request No.:	PGE_TURN006
PG&E File Name:	GRC-2023-PhI_DR_PGE_ TURN006
From:	Ned Allis, Exhibit (PG&E-10)
Request Date:	June 17, 2022
Due Date:	June 27, 2022
Response Date:	June 27, 2022

Please provide electronic responses to the following questions. Hard copy responses are unnecessary. The responses should be sent as e-mail attachments to the recipients below. If the files are too large to email, please contact the GRC coordinators below to upload the documents into a folder on the Electronic Secure File Transfer (ESFT) and notify the recipients below.

GRC 2023 Coordinators:
Rachel Keller, Victoria Anes
Gissell Morales, Maria Osorio
Sarah Phung and

GRC 2023 Discovery Manager:
Hannah Keller
at GRC@pge.com

SUBJECT: DEPRECIATION

EXHIBIT: TURN-18

1. Please refer to page 15-16 of Exhibit TURN-18. In the past five years, has Mr. Garrett recommended any survivor curve estimates that were based in whole or in part on the analysis of statistically aged data in any proceeding? If so, please provide a citation to the case and testimony showing such recommendations.

   Mr. Garrett does not recall recommending a survivor curve estimate based on the analysis of statistically aged data. In Mr. Garrett's experience, the data used to conduct a depreciation study are typically actual data (i.e., not statistically aged). Mr. Garrett typically uses the same data that the utility contends were used in conducting its depreciation study in formulating his survivor curve estimates.
2. Please refer to page 56 of TURN-18.
   a. Does Florida Power & Light (FPL) have a software account with a 5-year amortization period (or 5-year service life)?

      Mr. Garrett does not know whether FPL had a software account with a 5-year amortization period at the time it submitted the testimony cited in TURN's testimony.

b. If the response to part (a) is yes, does Mr. Garrett know or have an estimate of the original cost in FPL's 5-year software account compared to the original cost in the 20-year software account for SAP? If yes, please provide Mr. Garrett's estimate of these costs as well as support for these estimates. If not, please explain why Mr. Garrett did not perform this analysis for his testimony.

3. Please provide Mr. Garrett's understanding of how the statistical aging process works. The response should include the following:

   a. A narrative explaining Mr. Garrett's understanding of the statistical aging process.

   Mr. Garrett's understanding of the process Gannett Fleming used to statistically age the data in this case is limited to the explanations provided in the Company's testimony, exhibits, and discovery responses in this case, as well as the rebuttal testimony and discovery response provided in the test year 2020 GRC. TURN has attached an excerpt of that rebuttal testimony and PG&E's response to TURN DR 93, Question 3 from the prior GRC.

   b. The inputs needed to perform statistical aging, including:

   c. A description of the input data

   Please see the response to part "a" above.

   d. The parameters required to perform the process, such as ASL, survivor curve type, etc.

   Please see the response to part "a" above.

   e. Is Mr. Garrett aware of any authoritative depreciation texts/textbooks that discuss statistical aging? If so, please identity the text, cite to the relevant page number(s) and indicate whether they support that it is an acceptable approach?

   Mr. Garrett does not recall authoritative depreciation texts that discuss statistical aging.

   f. Do any of the authoritative depreciation texts/textbooks from part (c) use the word "manufactured" used to describe the statistical aging process? Please provide references to these sections of the texts/textbooks.

   Mr. Garrett is not aware whether authoritative depreciation texts use the word "manufactured" to describe the statistical aging process.

4. The following questions are in reference to an original table developed based on a 1999-2020 experience band (for example, the 1999-2020 experience band life table for Account 364 in the workpapers supporting Chapter 12 of Exhibit (PG&E-

10)

a. For each point on such a life table, how many years of experience are included in the development of the data point? Please explain your response in detail.

For an experience band of 1999-2020, there are 22 years of experience included in the development of the data points on the original life table.

b. For any account or depreciable group that has an expected average service life of 25 years or more, is every data point in a life table based on a 1999-2020 experience band based on fewer years of retirement experience than the average service life for the account? Please explain your reasoning and response in detail.

Yes.

c. For any account or depreciable group that has an expected average service life of 25 years or more, does every data point in a life table based on a 1999-2020 experience band have significantly fewer years of experience than the full life cycle of the property? For the purposes of this question, significantly fewer means 50% or less and the full life cycle of the property means the period from age zero to the maximum life of the survivor curve. Please explain your reasoning and response in detail.

The answer to this question would depend on the survivor curve selected, which would affect average life and maximum life. If the survivor curve selected was the R2-52 Iowa curve (which was selected for Account 364), then the data points on the observed life table for Account 364 would be associated with a total number of experience years that is less than 50% of the estimated full life cycle of property.

5. Please refer to Appendix D of TURN-18. From the standpoint of intergenerational equity and the matching principle, does straight-line depreciation include an inherent assumption that the service provided in each year of an asset's life is relatively equal? Please explain why or why not.

If the Commission were being asked in this GRC to establish depreciation parameters that would remain in effect without further change or review for the entire remaining life of current assets, there might be such an assumption. However, given regular GRC reviews and regular opportunities to adjust depreciation parameters going forward, it is less clear that there would be such an assumption. Furthermore, for both setting depreciation parameters and determining ratemaking adjustments that may be appropriate as part of the overall effort to achieve California's goals for carbon neutrality, intergenerational equity and the matching principle would be, at most, two of many principles the Commission would need to consider and balance in adopting reasonable outcomes.

6. Please refer to Appendix D of TURN-18 and the E3 forecasts of gas demand,

which was provided in the response to IndicatedShippers 001-Q07. Which of the E3 scenarios does TURN believe to be most likely (e.g., medium, high, etc.)? Please explain why. Which does TURN believe to be least likely? Please explain why.

The analysis and discussion in Appendix D of TURN-18 did not cite or rely on the E3 forecasts of gas demand. TURN's position on PG&E's proposed shift to the units of production method as set forth in Appendix D is indifferent to the various E3 scenarios. Therefore, for purposes of this proceeding, TURN has not assessed which of the E3 scenarios is most likely or least likely.

7. All else equal, does TURN believe that state goals for carbon neutrality are likely to result in service lives for gas mains being shorter, longer or the same as in the past? Please explain your response.

   TURN believes that state goals for carbon neutrality are likely to result in service lives for gas mains being shorter by some as yet undetermined amount. However, for purposes of rate recovery of existing or new investment in gas mains, it is not clear to TURN at this time how any change in service lives will impact the amount of rate recovery permitted, or the period over which such recovery would occur. As noted in TURN's testimony, in R.20-01-007 the Commission has undertaken determination of "the regulatory solutions and planning strategy that [it] should implement to ensure that, as the demand for natural gas declines, gas utilities maintain safe and reliable gas systems at just and reasonable rates, and with minimal or no stranded costs." Until the Commission makes such a determination, it is not clear what role expected service lives will play in setting rate recovery at any given time going forward.

8. All else equal, does TURN believe that state goals for carbon neutrality would result in service lives for gas services being shorter, longer or the same as in the past? Please explain your response.

   TURN believes that state goals for carbon neutrality are likely to result in service lives for gas services being shorter by some as yet undetermined amount. However, for purposes of rate recovery of existing or new investment in gas services, it is not clear to TURN at this time how any change in service lives will impact the amount of rate recovery permitted, or the period over which such recovery would occur. As noted in TURN's testimony, in R.20-01-007 the Commission has undertaken determination of "the regulatory solutions and planning strategy that [it] should implement to ensure that, as the demand for natural gas declines, gas utilities maintain safe and reliable gas systems at just and reasonable rates, and with minimal or no stranded costs." Until the Commission makes such a determination, it is not clear what role expected service lives will play in setting rate recovery at any given time going forward.

9. All else equal, does Mr. Garrett believe that state goals for carbon neutrality are

likely to result in service lives for gas mains being shorter, longer or the same as in the past? Please explain your response.

Mr. Garrett has not analyzed California's state goals for carbon neutrality or the likely impact on service lives for gas mains.

10. All else equal, does Mr. Garrett believe that state goals for carbon neutrality would result in service lives for gas services being shorter, longer or the same as in the past? Please explain your response.

    Mr. Garrett has not analyzed California's state goals for carbon neutrality or the likely impact on service lives for gas services.

11. All else equal, does TURN believe that state goals for carbon neutrality are likely to result in depreciation being higher, lower or the same as in the past? Please explain your response.

    For purposes of answering this question, TURN is assuming that "depreciation" means "depreciation expense associated with gas distribution equipment." TURN believes that state goals for carbon neutrality could result in depreciation being higher, lower, or the same as in the past. The actual result will depend on how the Commission resolves the numerous questions regarding "the regulatory solutions and planning strategy that [it] should implement to ensure that, as the demand for natural gas declines, gas utilities maintain safe and reliable gas systems at just and reasonable rates, and with minimal or no stranded costs," as described in R.20-01-007. Until the Commission makes such a determination, it will not be clear whether depreciation will be higher, lower or the same due to carbon neutrality.

12. All else equal, does Mr. Garrett believe that state goals for carbon neutrality are likely to result in depreciation being higher, lower or the same as in the past? Please explain your response.

    Mr. Garrett has not analyzed California's state goals for carbon neutrality or the likely impact on depreciation expense.

13. Please refer to page 56, lines 19-22. Was Mr. Allis the witness in the "other cases" cited by Mr. Garrett?

    Mr. Garrett does not know whether Mr. Allis testified, or to what extent he participated, in the case cited in footnote 57.

14. On page 9 of his testimony, Mr. Garrett discusses *Lindheimer v. Illinois Bell Telephone Co*. and states "[t]he *Lindheimer* Court also recognized that the original cost of plant assets, rather than present value or some other measure, is

the proper basis for calculating depreciation expense."

a. Is it Mr. Garrett's interpretation that the U.S. Supreme Court has found that the original cost of plant is the only acceptable basis for calculating depreciation expense?

   Mr. Garrett does not interpret the *Lindheimer* decision as having found that the original cost of plant is the only acceptable basis for calculating depreciation expense. Mr. Garrett has not undertaken a broad review of all U.S. Supreme Court decisions that may address the calculation of depreciation expense, and therefore does not have an opinion on whether other U.S. Supreme Court decisions find that the original cost of plant is the only acceptable basis for calculating depreciation expense.

b. Is it Mr. Garrett's opinion that *Lindheimer* or subsequent U.S. Supreme Court decisions preclude another measure, such as fair value, from being used to calculate depreciation expense?

   Mr. Garrett does not interpret the *Lindheimer* decision as precluding another measure, such as fair value, from being used to calculate depreciation expense. Mr. Garrett has not undertaken a broad review of all subsequent U.S. Supreme Court decisions that may address the calculation of depreciation expense, and therefore does not have an opinion on whether Lindheimer or subsequent U.S. Supreme Court decisions preclude other measures from being used to calculate depreciation expense.

c. If the responses to either part (a) or (b) is "yes," please provide all facts and rationale, including citations, that support Mr. Garrett's opinion.

15. On page 9 of his testimony, Mr. Garrett discusses *Lindheimer v. Illinois Bell Telephone Co*. and emphasizes the following in a quote from *Lindheimer*, "the company has the burden of making a convincing showing that the amounts it has charged to operating expenses for depreciation have not been excessive."

a. Does Mr. Garrett interpret this quote to mean that a Company must make a convincing showing that its depreciation rates are precisely correct or that a company instead has to make a convincing showing that its depreciation rates are not excessive? Please provide all support and justification for the response.

   Mr. Garrett interprets the cited quote to mean that the Company must make a convincing showing that its depreciation rates are not excessive.

b. In the same passage quoted on page 9 of Mr. Garrett's testimony, the U.S. Supreme Court states, regarding depreciation that "[t]he calculations are mathematical, but the predictions underlying them are essentially matters of opinion." Does Mr. Garrett agree that the statement that "the predictions underlying them are essentially matters of opinion" indicates that the U.S. Supreme Court recognizes that there is judgment involved in determining depreciation? If the response is no, please explain and provide all support and justification for the response.

Yes.

c. Please explain Mr. Garrett's understanding of how the accumulated depreciation component of rate base was determined in the rate case at issue in *Lindheimer*. Was rate base based on the recorded book depreciation reserve or on some other measure? Please provide all support and justification for the response. Additionally, please explain any differences between how the accumulated depreciation used to develop the rate base was determined in *Lindheimer* and how accumulated depreciation has been determined for the Company.

Mr. Garrett does not have an opinion on how the accumulated depreciation component of rate base was determined in the rate case at issue in Lindheimer.

d. In the state of Illinois at the time of *Lindheimer v. Illinois Bell Telephone Co.*, is Mr. Garrett aware of any statewide policies that would affect depreciation related to the telephone industry similar to the way the statewide policies regarding carbon emissions in California are expected to affect depreciation related to the gas industry?

No.

16. Please refer to page 11, lines 3-6 of TURN-18.

a. Please describe the "regulatory mechanisms that can ensure the utility fully recovers its prudent investment of the retired asset."

Mr. Garrett is not familiar with all of the regulatory mechanisms that have been used in California for recovery of the investment in plant that is retired and no longer used and useful. Mr. Garrett has learned from TURN that in its decision in PG&E's test year 2011 GRC, the Commission identified a number of such mechanisms adopted in various circumstances regarding assets retired before they are fully depreciated. Mr. Garrett is also aware that a regulatory asset is a mechanism that could be used to recover costs of retired assets that have not been fully depreciated.

b. For each mechanism provided in part (a), does "fully recovers" include both a return of and return on the retired asset? Please explain the response in detail.

Mr. Garrett used the term "fully recovers" to describe the "return of" the utility's investment through depreciation. It is Mr. Garrett's understanding that the "return of" and "return on" a utility's investment in a retired asset would be determined by the regulator.

17. Please refer to page 99 of Exhibit TURN-18. TURN has modified the quote on lines 18-19 to read "[utility-proposed scenarios]"

    a. Please provide the original text from this passage of the cited order.

    The sentence as it appears in TURN's testimony states, "Therefore, at this time, the Department rejects the Company's proposed phase-in of depreciation rates associated with [the utility-proposed scenarios]." The sentence as it appears in the cited order states, "Therefore, at this time, the Department rejects the Company's proposed phase-in of depreciation rates associated with the Shorter Service Lives Case 1 scenario and the Shorter Service Lives Case 2 scenario."

    b. Please explain in detail TURN's understanding of the "utility-proposed scenarios" in the cited case.

    As described at page 226 of the cited order of the Massachusetts Department of Public Utilities, the two utility-proposed scenarios assume shorter service lives for three plant accounts "in anticipation of reductions in natural gas consumption and demand stemming from the Commonwealth's decarbonization goals, resulting in a higher composite depreciation accrual rate.

    c. Were the referenced "utility-proposed scenarios" the same as proposed by PG&E in the instant case? If yes, please provide all support. If no, please explain any differences.

    In TURN's view, the utility-proposed scenarios that the Massachusetts DPU considered and rejected are the same as those PG&E has proposed here in that they would result in a higher depreciation rate than would otherwise be the case. The scenarios are different in that the utility relied on accelerated depreciation approaches in Massachusetts, which is different than the units of production approach PG&E has proposed here. But for both approaches, the impact is an increased depreciation rate in the near term as a response to still-developing ratemaking policies tied to achieving the state's decarbonization goals.

18. Please refer to page 99, lines 3-6, where TURN quotes PG&E's depreciation study as stating, in reference to New York and Massachusetts, "regulatory commissions in both states have been presented with accelerated depreciation proposals 'as a first step to address' decarbonization goals."

a. The citation following this statement references pp. 12-27 and 12-35 of Exhibit PG&E-10. Please provide the specific page and line number(s) from which TURN sourced this statement.

At page 12-27, lines 4-9 of PG&E-10 (11/05/21 version), the testimony states, "California is not the only state for which the gas industry is facing these issues. For example, states in the northeastern U.S. such as New York and Massachusetts have similar goals for significant carbon emission reductions over a similar period. As discussed below, some of the scenarios considered for PG&E's depreciation study have been considered or proposed by utilities in these states."

At page 12-35, lines 2-4 of PG&E-10 (11/05/21 version), the testimony states, "In recent cases in New York and Massachusetts, similar scenarios have been proposed by utilities as a first step to address the impact of decarbonization goals in these states."

b. Did PG&E's testimony use the term "accelerated depreciation" in the referenced section? Please provide specific citations for your response.

The term "similar scenarios" mentioned on page 12-35 refers to the two shorter lives scenarios described on the previous page of PG&E's testimony, which TURN understands to be accelerated depreciation proposals. However, PG&E used the terms "Shorter Service Lives Case 1" and "Shorter Service Lives Case 2" rather than the term "accelerated depreciation."

c. What is TURN's understanding of the specific depreciation proposals that have been proposed by the referenced New York and Massachusetts utilities. Were they based on the UoP Method? Did they incorporate shorter service lives? Was another approach used?

TURN's understanding is that the Massachusetts utility National Grid proposed a phased-in implementation of depreciation rates, where the first two rate years would base rates on a "Shorter Service Lives Case 1" scenario, and the next three years would base rates on a "Shorter Service Lives Case 2" scenario. From PG&E's testimony, TURN infers that the "Shorter Service Lives Case 1" scenario the utility claims to have considered here proposed to shorten the service lives by five years, and the "Shorter Service Lives Case 2" scenario proposed to shorten the service lives by ten years. (PG&E-10, p. 12-34 to 12-35 (11/05/21 version).

TURN's understanding is that the New York utility Orange and Rockland Utilities proposed to shorten the service lives for certain long-lived gas plant accounts by five years from what the utility had historically experienced. (Orange and Rockland Utilities Direct Testimony of Depreciation Panel, pp. 10 and 28.)

PACIFIC GAS AND ELECTRIC COMPANY
2023 General Rate Case Phase I
Application 21-06-021
Data Response

PG&E Data Request No.:	CalAdvocates_045-Q06		
PG&E File Name:	GRC-2023-PhI_DR_CalAdvocates_045-Q06		
Request Date:	August 27, 2021	Requester DR No.:	PubAdv-PG&E-045-ANU
Date Sent:	September 14, 2021	Requesting Party:	Public Advocates Office
PG&E Witness:	Paul Hunt	Requester:	Anusha Nagesh

SUBJECT: CHAPTER 14 AND FOLLOW UP TO DR-015, ANU AND DR-016-ANU

QUESTION 06

Referring to PG&E's data request response to Q.13 of DR-015-ANU in document titled "GRC-2023-PhI_DR_CalAdvocates_015-Q13," please answer the following questions:

a. Provide recorded customer deposits for each non-residential customer category from recorded years 2016 to 2020 in MS Excel with all formulas intact.

b. Identify where and in which of the Commission's decisions was PG&E disallowed to recover customer deposits for small-business customers going forward.

ANSWER 06

a. Please see GRC-2023-PhI_DR_CalAdvocates_045-Q06Atch01. This spreadsheet provides data for non-residential customer cash deposits by month from 2016 through 2020 from PG&E's customer information system. PG&E cannot provide data on deposits by "each non-residential customer category" for the requested period as PG&E did not track deposits for subcategories within the non-residential customer class.

b. PG&E believes that the phrase "disallowed to recover customer deposits" in the question is vague and may call for a legal conclusion. Subject to and without waiving these objections, please see Commission Resolution M-4842, issued on April 17, 2020, which required PG&E to waive collecting customer deposits for residential and small commercial customers. On page 4, the Resolution states: "All residential and small business customers in California are eligible for the emergency customer protections set forth in this Resolution." On page 5, the Resolution requires PG&E to "(1) waive deposit requirements for residential customers seeking to reestablish service for one year … [and] (6) … waive deposit and late fee requirements for residential customers …"

   At page one, Resolution M-4842 extended these customer protections for one year from the date of the Resolution, or until April 16, 2021. Resolution M-4849, at page 33, Ordering Paragraph 1, extended these customer protections through June 30, 2021.

NONRESIDENTIAL CASH DEPOSITS BY MONTH, 2016-2020

Month - Year	Deposits Volumes on hand	Deposit Amount on hand
Jan-16	45,050	$102,703,472
Feb-16	45,032	$101,929,534
Mar-16	45,110	$101,638,239
Apr-16	45,289	$101,996,543
May-16	46,024	$103,739,698
Jun-16	46,334	$104,809,513
Jul-16	46,103	$104,781,735
Aug-16	45,981	$105,473,338
Sep-16	45,812	$107,322,068
Oct-16	45,487	$108,356,968
Nov-16	45,293	$108,598,472
Dec-16	44,877	$108,468,555
Jan-17	44,333	$108,368,419
Feb-17	43,799	$108,623,863
Mar-17	43,218	$108,677,563
Apr-17	42,256	$105,206,520
May-17	41,527	$104,550,704
Jun-17	40,489	$104,421,375
Jul-17	39,412	$104,373,737
Aug-17	37,843	$103,398,941
Sep-17	36,974	$103,161,743
Oct-17	36,222	$103,208,259
Nov-17	36,048	$102,933,910
Dec-17	35,937	$103,006,589
Jan-18	35,693	$102,794,303
Feb-18	35,445	$104,138,227
Mar-18	35,511	$104,340,455
Apr-18	35,606	$107,632,995
May-18	35,872	$109,221,314
Jun-18	36,015	$110,307,002
Jul-18	36,159	$111,615,422
Aug-18	35,925	$111,114,765
Sep-18	35,711	$112,321,511
Oct-18	35,667	$112,046,286
Nov-18	35,389	$111,442,168
Dec-18	35,281	$111,893,215
Jan-19	34,737	$111,260,692
Feb-19	34,139	$109,795,928
Mar-19	33,252	$107,817,467
Apr-19	32,395	$107,717,769
May-19	31,871	$106,588,504
Jun-19	31,626	$105,516,679
Jul-19	31,808	$106,875,775
Aug-19	32,096	$108,253,638
Sep-19	31,915	$108,736,333
Oct-19	31,312	$108,255,005
Nov-19	30,883	$108,636,484
Dec-19	30,254	$108,395,534
Jan-20	29,773	$106,848,667
Feb-20	29,543	$106,293,194
Mar-20	29,269	$105,634,106
Apr-20	28,316	$106,036,493
May-20	26,798	$104,336,900
Jun-20	25,398	$102,285,412
Jul-20	23,814	$99,898,006
Aug-20	22,133	$96,699,532
Sep-20	19,403	$94,079,133
Oct-20	17,646	$91,957,872
Nov-20	16,027	$91,657,680
Dec-20	14,715	$89,662,974

PACIFIC GAS AND ELECTRIC COMPANY
2023 General Rate Case Phase I
Application 21-06-021
Data Response

PG&E Data Request No.:	CalAdvocates_083-Q01		
PG&E File Name:	GRC-2023-PhI_DR_CalAdvocates_083-Q01		
Request Date:	September 24, 2021	Requester DR No.:	PubAdv-PG&E-083-ANU
Date Sent:	October 13, 2021	Requesting Party:	Public Advocates Office
PG&E Witness:	Paul Hunt	Requester:	Anusha Nagesh

SUBJECT: CHAPTERS 14, 12, FOLLOW-UP TO DR-016-ANU, DR-045-ANU, AND DR-052-ANU

QUESTION 01

Referring to PG&E's responses to data request PubAdv-PG&E-045-ANU, Q.6 and data request PubAdv-PG&E-015-ANU, Q.13, explain how PG&E forecasts the customer deposit of $64 million in TY 2023 from the recorded data provided in response to data request PubAdv-PG&E-045-ANU, Q.6.

ANSWER 01

The data provided in the response to data request PubAdv-PG&E-045-ANU, Q.6 were extracted within a few days before PG&E provided the response to Public Advocates, and after PG&E provided the response to data request PubAdv-PG&E-015-ANU, Q.13. Because of this timing, to the witness's knowledge, the recorded data provided in the response to data request PubAdv-PG&E-045-ANU, Q.6 were not used to forecast the customer deposit of $64 million in TY 2023 that is referenced in the question.

Calculating a forecast from the recorded data provided in response to data request PubAdv-PG&E-045-ANU, Q.6 yields a forecast of $81.5 million for April 2021. This assumes that residential and small commercial customer deposits waived by Commission Resolution M-4842 were refunded by the end of April 2021. This forecast is found in GRC-2023-PhI_DR_CalAdvocates_083-Q01Atch01.xlsx. Assuming no change thereafter results in a forecast of $81.5 million for 2023.

Notwithstanding the projection of $64 million in customer deposits referenced above, PG&E believes that $81.5 million is the correct projection for 2023. PG&E will incorporate this projection in a future errata correction to the Results of Operation model.

Pacific Gas and Electric Company
2023 General Rate Case
Data Request PubAdv-PG&E-083-ANU, Question 1
Nonresidential Customer Deposits

Line No.	Month	2020 Nonresidential Cash Deposits, Answer to Data Request PubAdv-PG&E-045-ANU, Question 6, Attachment 01	Change From Prior Month	Comment
	(A)	(B)	(C)	(D)
	2020			
1	January	106,848,667		
2	February	106,293,194		
3	March	105,634,106		
4	April	106,036,493		Commission Resolution M-4842, issued on April 17, 2020, required PG&E to waive collecting customer deposits on residential and small commercial customers
5	May	104,336,900	(1,699,593)	
6	June	102,285,412	(2,051,488)	
7	July	99,898,006	(2,387,406)	
8	August	96,699,532	(3,198,474)	
9	September	94,079,133	(2,620,399)	
10	October	91,957,872	(2,121,261)	
11	November	91,657,680	(300,192)	
12	December	89,662,974	(1,994,706)	
13	**Average Annual Balance**	**99,615,831**		
14	Average Reduction, Nonresidential Cash Deposits, April 2020 to December 2020	2,046,690		
	2021	**Projected Nonresidential Cash Deposits***		*** Residential and small commercial customer deposits expected to be fully refunded by the end of April 2021**
15	January	87,616,284	(2,046,690)	
16	February	85,569,594	(2,046,690)	
17	March	83,522,904	(2,046,690)	
18	April	81,476,215	(2,046,690)	Small commercial customer deposits refunded by the end of April 2021
19	May	81,476,215	-	
20	June	81,476,215	-	
21	July	81,476,215	-	
22	August	81,476,215	-	
23	September	81,476,215	-	
24	October	81,476,215	-	
25	November	81,476,215	-	
26	December	81,476,215	-	

PACIFIC GAS AND ELECTRIC COMPANY
2023 General Rate Case Phase I
Application 21-06-021
Data Response

PG&E Data Request No.:	CalAdvocates_112-Q16		
PG&E File Name:	GRC-2023-PhI_DR_CalAdvocates_112-Q16		
Request Date:	October 12, 2021	Requester DR No.:	PubAdv-PG&E-112-ANU
Date Sent:	October 22, 2021	Requesting Party:	Public Advocates Office
PG&E Witness:	Paul Hunt	Requester:	Anusha Nagesh

SUBJECT: CHAPTERS 10, 14, 16 AND FOLLOW-UP TO DATA REQUEST PUBADV-PG&E-045-ANU

Follow-Up to Data Request PubAdv-PG&E-045-ANU

QUESTION 16

Referring to PG&E's response to data request PubAdv-PG&E-045-ANU, Q.6, in document titled "GRC-2023-PhI_DR_CalAdvocates_045-Q06," please answer the below questions:

a. Are these restrictions applicable to TY 2023?

b. Identify where in the workpapers are the customer deposits accounted for.

ANSWER 16

a. PG&E objects to this question as vague. Subject to and without waiving this objection, D.20-06-003 restricts PG&E from collecting residential customer deposits. (D.20-06-003, pp. 37-44, Ordering Paragraphs 8 and 9.) Regarding nonresidential customer deposits, PG&E is permitted to collect them as of July 1, 2021, as the restrictions established by Resolution M-4842 and extended by Resolution M-4849 expired. PG&E cannot predict at this time what procedures regarding customer deposits will be in effect in 2023.

b. PG&E objects to this question as vague, as PG&E does not know what is meant by "accounting for" customer deposits. Subject to and without waiving this objection, PG&E's projection of customer deposits for test year 2023 is supported by workpaper page 14-154 in the workpapers for Exhibit (PG&E-10), Chapter 14.

   The customer deposits adjustment to PG&E's test year 2023 revenue requirement is shown on workpaper page 17-177 of the workpapers for Exhibit (PG&E-10), Chapter 17, at lines 26-28.

PACIFIC GAS AND ELECTRIC COMPANY
2023 General Rate Case Phase I
Application 21-06-021
Data Response

PG&E Data Request No.:	TURN_151-Q010		
PG&E File Name:	GRC-2023-PhI_DR_TURN_151-Q010		
Request Date:	March 7, 2022	Requester DR No.:	TURN-PG&E-151
Date Sent:	March 21, 2022	Requesting Party:	The Utility Reform Network
PG&E Witness:	Paul Hunt	Requester:	Hayley Goodson

SUBJECT: PG&E-10-R, CHAPTER 14

QUESTION 010

In PG&E-10, p. 14-15, PG&E provides an average projection of customer deposits in 2023 of $81.5 million,

a. Please provide the working paper supporting this calculation.

b. Please provide the monthly average customer deposits in each year 2018, 2019, 2020, and 2021.

ANSWER 010

a. The relevant workpaper is page WP 14-154 in the workpapers for Exhibit (PG&E-10), Chapter 14, provided on February 28, 2022, and available on PG&E's website at https://pgera.azurewebsites.net/Regulation/ValidateDocAccess?docID=691761. A copy of the workpaper page is provided in the attachment GRC-2023-PhI_DR_TURN_151-Q010Atch01.pdf.

b. PG&E objects to this question as it calls for information that was not available at the time of PG&E's 2023 GRC filing or which was not used as the basis for PG&E's 2023 forecast. Subject to and without waiving that objection, please see the remainder of this answer.

For data prior to and including March 2021, please see the attachment GRC-2023-PhI_DR_TURN_151-Q010Atch02.pdf. Monthly customer deposits for the remainder of 2021 are as follows:

Month	**Customer Deposit Balances ($ Thousands)**
April 2021	82,544
May 2021	81,956
June 2021	82,612
July 2021	81,657
August 2021	81,308

Month	Customer Deposit Balances ($ Thousands)
September 2021	81,048
October 2021	80,555
November 2021	76,273
December 2021	76,004

Please note that customer deposits data for April 2021 and later are not likely to be comparable to customer deposits data for earlier periods because of the following events:

1. In D.20-06-003 (disconnection rulemaking), the Commission permanently barred PG&E from requiring customer deposits for residential customers to establish or reestablish service. (D.20-06-003, pp. 37-44, Ordering Paragraphs 8 and 9.)
2. Commission Resolution M-4842, issued on April 17, 2020, required PG&E to waive collecting customer deposits for residential and small commercial customers. At page one, Resolution M-4842 extended these customer protections for one year from the date of the Resolution, or until April 16, 2021. Resolution M-4849, at page 33, Ordering Paragraph 1, extended these customer protections through June 30, 2021.

Pacific Gas & Electric Company
2023 General Rate Case
Exhibit PG&E-10, Chapter 14, Working Cash
Customer Deposits Projection (Excludes Residential)

Line No.	Month	2020 Nonresidential Cash Customer Deposits*	Change From Prior Month In 2020	2021 Projected Nonresidential Cash Deposits**		2022 Projected Nonresidential Cash Deposits	2023 Projected Nonresidential Cash Deposits
	(A)	(B)	(C)	(D)		(E)	(F)
1	January	106,848,667		87,616,284		81,476,215	81,476,215
2	February	106,293,194		85,569,594		81,476,215	81,476,215
3	March	105,634,106		83,522,904		81,476,215	81,476,215
4	April	106,036,493		81,476,215		81,476,215	81,476,215
5	May	104,336,900	(1,699,593)	81,476,215	***	81,476,215	81,476,215
6	June	102,285,412	(2,051,488)	81,476,215		81,476,215	81,476,215
7	July	99,898,006	(2,387,406)	81,476,215		81,476,215	81,476,215
8	August	96,699,532	(3,198,474)	81,476,215		81,476,215	81,476,215
9	September	94,079,133	(2,620,399)	81,476,215		81,476,215	81,476,215
10	October	91,957,872	(2,121,261)	81,476,215		81,476,215	81,476,215
11	November	91,657,680	(300,192)	81,476,215		81,476,215	81,476,215
12	December	89,662,974	(1,994,706)	81,476,215		81,476,215	81,476,215
13	**Average Annual Balance**	**99,615,831**		**82,499,559**		**81,476,215**	**81,476,215**
14	Average Reduction, Nonresidential Cash Deposits, April 2020 to December 2020	2,046,690					
15	Long Term Debt Rate ****						4.170%
16	Commercial Paper Rate*****						0.70%
17	Difference in rates						3.48%
18	**Adjustment to revenues**					**$**	**(2,831,298)**
19	**Electric Distribution**					**$**	**(1,981,909)**
20	**Gas Distribution**					**$**	**(849,390)**

Notes:

* Commission Resolution M-4842, issued on April 17, 2020, required PG&E to waive collecting customer deposits on residential and small commercial customers

** Residential and small commercial customer deposits expected to be fully refunded by the end of April 2021

*** Small commercial customer deposits refunded by the end of April 2021

**** PG&E updated its long term cost of debt from 5.16% to 4.17%, effective July 1, 2020, in Advice Letter 4275G/5887E, approving PG&E's Cost of Debt Update in Compliance with OP 6 of Decision 20-05-053. The average 2020 balance is 4.665%

***** Average of three-month, non-financial commercial paper rate, as published in the Federal Reserve Statistical Release, H-15, pursuant to company tariffs and CPUC Decision No. 91269.

PACIFIC GAS AND ELECTRIC COMPANY
2023 General Rate Case
Response to Public Advocates Office
Master Data Request

PG&E Data Request No.:	CalAdvocates_MDR11		
PG&E File Name:	GRC-2023-PhI_DR_CalAdvocates_MDR11-Q17		
Request Date:	November 2, 2020	Requester DR No.:	MDR11
Date Sent:	June 30, 2021	Requesting Party:	Public Advocates Office
PG&E Witness:	Paul T. Hunt, Jr.	Requester:	Truman Burns

CHAPTER 11: WORKING CASH/WORKING CAPITAL

QUESTION 17

Provide the monthly balances for customer deposits for the last 5 years.

ANSWER 17

	Customer Deposit Balances ($ Thousands)						
Line							
No.	Month	2016	2017	2018	2019	2020	2021
1	December, prior	176,191	176,005	168,155	174,587	160,582	104,155
2	January	173,864	176,548	168,961	173,460	160,233	96,672
3	February	174,124	177,198	170,686	171,422	159,686	91,262
4	March	173,584	176,635	170,542	166,649	158,470	83,854
5	April	173,891	173,291	174,422	165,051	157,930	
6	May	175,070	172,411	175,835	163,497	153,569	
7	June	175,419	172,276	176,920	161,952	147,742	
8	July	174,423	172,372	179,467	162,399	140,250	
9	August	174,228	171,572	178,890	163,554	132,653	
10	September	175,151	171,198	178,590	162,736	125,225	
11	October	176,129	169,917	177,769	160,509	117,114	
12	November	176,119	169,300	176,305	161,147	111,147	
13	December, current	176,005	168,155	174,587	160,582	104,155	
14	12 Month Average	174,834	172,573	175,248	164,413	139,015	

PACIFIC GAS AND ELECTRIC COMPANY
2023 General Rate Case Phase I
Application 21-06-021
Data Response

PG&E Data Request No.:	CalAdvocates_015-Q04		
PG&E File Name:	GRC-2023-PhI_DR_CalAdvocates_015-Q04		
Request Date:	August 4, 2021	Requester DR No.:	PubAdv-PG&E-015-ANU
Date Sent:	August 26, 2021	Requesting Party:	Public Advocates Office
PG&E Witness:	Paul Hunt	Requester:	Truman Burns

SUBJECT: CHAPTER 14 – WORKING CASH

QUESTION 04

Referring to Exhibit PG&E-10, page 14-9, line 6, PG&E states “For current federal income taxes, PG&E assumes a 90-day expense lag.” Please answer the following questions:

a. Explain in detail how PG&E forecasted a 90-day expense lag for federal Income tax.

b. Provide all related workpapers, documents used to forecast the 90-day expense lag for federal income tax.

ANSWER 04

As a result of further analysis, PG&E has determined it is necessary to update its assumption for the federal income tax lag from 90 days to 48.66 days. PG&E will submit a workpaper and/or testimony updating the federal and state expense lags by August 30, 2021.

PACIFIC GAS AND ELECTRIC COMPANY
2023 General Rate Case Phase I
Application 21-06-021
Data Response

PG&E Data Request No.:	CalAdvocates_068-Q06		
PG&E File Name:	GRC-2023-PhI_DR_CalAdvocates_068-Q06		
Request Date:	September 15, 2021	Requester DR No.:	PubAdv-PG&E-068-ANU
Date Sent:	September 28, 2021	Requesting Party:	Public Advocates Office
PG&E Witness:	Paul Hunt	Requester:	Anusha Nagesh

SUBJECT: CHAPTERS 10, 11,14 AND FOLLOW-UP TO DATA REQUEST PUBADV-PG&E-045-ANU

QUESTION 06

Referring to exhibit PG&E-10, Chapter 14, please provide annual federal and state income tax lag recorded for the last 10 years (2011-2021).

ANSWER 06

The discussion in Exhibit (PG&E-10), Chapter 14, regarding the expense lag for current federal and state income taxes has been superseded by the discussion in Exhibit (PG&E-10-R), Chapter 14, on the same subject. Exhibit (PG&E-10-R) was served on all parties to PG&E's 2023 GRC on August 27, 2021.

PG&E does not record the annual federal and state income tax lag in the normal course of business. However, PG&E has calculated a state income tax expense lag from estimated tax payments for the years 2011, 2012, and 2015 through 2018:

Year	State Income Tax Expense Lag Derived From Estimated Tax Payments
2011	136
2012	-45.7
2015	166.5
2016	291
2017	230.7
2018	75.5

These calculations are provided in CalAdvocates_068-Q06Atch01.xlsx.

For reasons explained in the answer to question 08 of this data request set, it would not be appropriate to derive an expense lag for state income taxes in the 2023 GRC from the data provided in this answer.

PACIFIC GAS AND ELECTRIC COMPANY
2023 General Rate Case Phase I
Application 21-06-021
Data Response

PG&E Data Request No.:	CalAdvocates_068-Q07		
PG&E File Name:	GRC-2023-PhI_DR_CalAdvocates_068-Q07		
Request Date:	September 15, 2021	Requester DR No.:	PubAdv-PG&E-068-ANU
Date Sent:	September 28, 2021	Requesting Party:	Public Advocates Office
PG&E Witness:	Paul Hunt	Requester:	Anusha Nagesh

SUBJECT: CHAPTERS 10, 11,14 AND FOLLOW-UP TO DATA REQUEST PUBADV-PG&E-045-ANU

QUESTION 07

Referring to exhibit PG&E-10, page 14-9, lines 6 to 9, provide estimated federal and state income tax lag recorded for years where PG&E did not make tax payments in the last 10 years (2011-2021).

ANSWER 07

The discussion in Exhibit (PG&E-10), Chapter 14, regarding the expense lag for current federal and state income taxes has been superseded by the discussion in Exhibit (PG&E-10-R), Chapter 14, on the same subject. Exhibit (PG&E-10-R) was served on all parties to PG&E's 2023 GRC on August 27, 2021.

PG&E does not record the annual federal and state income tax lag in the normal course of business. In previous GRCs, PG&E has 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.

However, there are years in which PG&E's consolidated tax group will pay no income taxes, for various reasons. For example, as a result of the claims paid by PG&E to wildfire victims in 2020, PG&E does not expect to pay federal or state income taxes for a number of years. This occurs because the amount of claims that PG&E can deduct on its consolidated tax return exceeds its taxable income, and in accordance with the Internal Revenue Code, PG&E is required to carry forward to future years deductions exceeding taxable income. Those deductions that are carried forward are called Net Operating Losses (NOLs). In the case of the NOLs from the recent payment of wildfire claims, as those NOLs are applied to taxable income in future years, the tax benefits of using those NOLs to reduce income taxes accrue to shareholders, since they paid the claims. (Certain tax benefits accruing to shareholders will be used by shareholders to fund a trust to credit customers for charges on recovery bonds related to the rate-neutral financing of some of the wildfire claim payments.)

With respect to NOLs due to losses, temporary or otherwise, borne by shareholders, as stipulated in Order Instituting Investigation 24 (OII 24, D.84-05-036), and under the construct of California utility ratemaking, such NOLs and the tax benefits do not increase or decrease a utility's cost of service or rate base. OII 24 established the principle that any reduction in tax obligations resulting from expenses that are not allowed for ratemaking accrue to shareholders. This kind of NOL is created when the utility has incurred expenses that it cannot recover in rates and are in excess of its taxable income. In that case, shareholders bear the costs of the unrecovered expenses, and therefore, the tax benefits of those deductions taken accrue to shareholders. The unused shareholder deductions can be applied against taxable income in future years for the benefit of shareholders. However, they do not yield a cash benefit to shareholders until the time they are applied to offset income tax owed.

Because NOLs that arose from costs borne by shareholders are not compensated as part of the cost of service ratemaking, these NOLs are not included in rate base. As a corollary, there is no impact on rate base when these NOLs are used to offset a cash tax liability for PG&E's consolidated tax return group according to the IRS rules and guidance. The use of the NOLs provides a tax benefit to shareholders that is created by tax law. If the tax benefit did not accrue to shareholders, ratepayers would effectively avoid the tax liability included in the cost of service. As a result, the concepts embodied in OII 24 require that the working cash calculation should not provide a secondary benefit to ratepayers that belongs to shareholders. Applying that concept to the lead-lag study, the cash is "paid" to shareholders as it is received in revenue from customers, and hence the expense lag is set to be equal to the revenue lag, resulting in no benefit or detriment to ratepayers in working cash. This methodology applies to both federal and state income taxes.

In all cases, the expense lag is no more than equal to the revenue lag. PG&E proposes to set both the federal income tax expense and the state income tax expense lags equal to the revenue lag of 48.66 days

PACIFIC GAS AND ELECTRIC COMPANY
2023 General Rate Case Phase I
Application 21-06-021
Data Response

PG&E Data Request No.:	CalAdvocates_068-Q08		
PG&E File Name:	GRC-2023-PhI_DR_CalAdvocates_068-Q08		
Request Date:	September 15, 2021	Requester DR No.:	PubAdv-PG&E-068-ANU
Date Sent:	September 28, 2021	Requesting Party:	Public Advocates Office
PG&E Witness:	Paul Hunt	Requester:	Anusha Nagesh

SUBJECT: CHAPTERS 10, 11,14 AND FOLLOW-UP TO DATA REQUEST PUBADV-PG&E-045-ANU

QUESTION 08

Referring to exhibit PG&E-10, page 14-9, lines 6 to 9, provide a detailed explanation on how PG&E's initial estimate of 90-day federal and state income tax lag was forecasted.

ANSWER 08

The discussion in Exhibit (PG&E-10), Chapter 14, regarding the expense lag for current federal and state income taxes has been superseded by the discussion in Exhibit (PG&E-10-R), Chapter 14, on the same subject. Exhibit (PG&E-10-R) was served on all parties to PG&E's 2023 GRC on August 27, 2021.

In Exhibit (PG&E-10), Chapter 14, PG&E did not propose an expense lag of 90 days for state income tax expense. PG&E proposed an expense lag of 75.90 days, as shown in original Tables 14-3 through 14-6. The calculation of this expense lag was supported by workpaper pages 14-92 and 14-93.

Regarding the expense lag for federal income tax expense, PG&E was aware that the federal net operating loss (NOL) is expected to increase in 2023, followed by decreases in 2024 through 2026. PG&E initially thought that this would imply a federal income tax expense lag of 365 days for 2023, followed by an expense lag of zero days for the following three years. Since the working cash model is not recalculated for years after the test year, PG&E averaged the four expense lags together and assumed 90 days for the federal income tax expense lag. However, PG&E continued to analyze the federal and state income tax expense lags and discovered that this approach is not correct. PG&E subsequently provided Exhibit (PG&E-10-R) to correct these expense lag calculations.

See also the response to question 7 in this data request explaining why the original approach was incorrect.

PACIFIC GAS AND ELECTRIC COMPANY
2023 General Rate Case Phase I
Application 21-06-021
Data Response

PG&E Data Request No.:	CalAdvocates_068-Q09		
PG&E File Name:	GRC-2023-PhI_DR_CalAdvocates_068-Q09		
Request Date:	September 15, 2021	Requester DR No.:	PubAdv-PG&E-068-ANU
Date Sent:	September 28, 2021	Requesting Party:	Public Advocates Office
PG&E Witness:	Paul Hunt	Requester:	Anusha Nagesh

SUBJECT: CHAPTERS 10, 11,14 AND FOLLOW-UP TO DATA REQUEST PUBADV-PG&E-045-ANU

QUESTION 09

Referring to exhibit PG&E-10, page 14-9, lines 6 to 9, was PG&E's initial forecast of 90-day tax lag based on income tax payment due date?

ANSWER 09

PG&E assumes that this question refers to the federal income tax expense lag of 90 days in Exhibit (PG&E-10). The discussion in Exhibit (PG&E-10), Chapter 14, regarding the expense lag for current federal and state income taxes has been superseded by the discussion in Exhibit (PG&E-10-R), Chapter 14, on the same subject. Exhibit (PG&E-10-R) was served on all parties to PG&E's 2023 GRC on August 27, 2021.

Please also see the answer to Question 08 of this data request set.

PACIFIC GAS AND ELECTRIC COMPANY
2023 General Rate Case Phase I
Application 21-06-021
Data Response

PG&E Data Request No.:	TURN_061-Q05		
PG&E File Name:	GRC-2023-PhI_DR_TURN_061-Q05		
Request Date:	November 23, 2021	Requester DR No.:	TURN-PG&E-61
Date Sent:	December 9, 2021	Requesting Party:	The Utility Reform Network
PG&E Witness:	Paul Hunt	Requester:	Hayley Goodson

SUBJECT: WORKING CASH (PG&E EXHIBIT 10-R, CH. 14)

Questions refer to PG&E-10-R, Chapter 14 unless otherwise indicated.

QUESTION 05

Does PG&E anticipate any net loss carry forwards arising from expenses disallowed from recovery under AB 1054 such as PG&E's non-recoverable initial $3.2 billion contribution to the Wildfire Insurance Fund or from its required future contributions?

a. In the answer to the question above is affirmative, please provide a listing of disallowed costs, the estimated ranges of potential net operating loss carry forwards, and the timing of their availability for utilization.

b. If the answer to the question above is negative, please explain why.

ANSWER 05

This answer is limited to expenses listed in the question: PG&E's initial contribution to the Wildfire Insurance Fund and future contributions. PG&E notes that its initial contribution to the Wildfire Insurance Fund was approximately $4.8 billion, not $3.2 billion as suggested in the question. AB 1054 also established procedures and standards for the Commission to follow when a utility seeks cost recovery in a catastrophic wildfire proceeding. This answer does not address any such costs.

As noted, PG&E's initial contribution to the Wildfire Insurance Fund was approximately $4.8 billion. This is to be followed by ten annual contributions of approximately $192.6 million, from 2020 through 2029. For income tax purposes, each contribution is amortized from the year it is made through 2035. The aggregate amortization in any year from 2020 through 2035 ranges from approximately $167 million to $510 million. Please see the projected amortizations in attachment GRC-2023-PhI_DR_TURN_061-Q05Atch01.xlsx.

a. The IRS, in a rate-making context, provides authority that a net operating loss (NOL) is first attributable to accelerated tax depreciation.[1] Outside of rate-making,

[1] See IRS Private Letter Rulings 201438003 and 201519021.

PG&E is not aware of any IRS authority that provides an ordering of expenses/deductions or that specifies the specific makeup or cause of a net operating loss. Therefore, based on current IRS authorities, PG&E cannot affirmatively say that the AB1054 nonrecoverable expenses contributed to the NOL carryforward.

b. See response to a. above.

Pacific Gas & Electric
Tax Amortization
July 2020-June 2035

Year	Total	2020 (6 months)	2021	2022	2023	2024	2025	2026	2027	2028	2029	2030	2031	2032	2033	2034	2035 (six months)	Total
2020	(4,815,000,000)	(160,500,000)	(321,000,000)	(321,000,000)	(321,000,000)	(321,000,000)	(321,000,000)	(321,000,000)	(321,000,000)	(321,000,000)	(321,000,000)	(321,000,000)	(321,000,000)	(321,000,000)	(321,000,000)	(321,000,000)	(160,500,000)	(4,654,500,000)
2020	(192,600,000)	(6,420,000)	(12,840,000)	(12,840,000)	(12,840,000)	(12,840,000)	(12,840,000)	(12,840,000)	(12,840,000)	(12,840,000)	(12,840,000)	(12,840,000)	(12,840,000)	(12,840,000)	(12,840,000)	(12,840,000)	(6,420,000)	(186,180,000)
2021	(192,600,000)		(13,282,759)	(13,282,759)	(13,282,759)	(13,282,759)	(13,282,759)	(13,282,759)	(13,282,759)	(13,282,759)	(13,282,759)	(13,282,759)	(13,282,759)	(13,282,759)	(13,282,759)	(13,282,759)	(6,641,379)	(185,958,621)
2022	(192,600,000)			(14,266,667)	(14,266,667)	(14,266,667)	(14,266,667)	(14,266,667)	(14,266,667)	(14,266,667)	(14,266,667)	(14,266,667)	(14,266,667)	(14,266,667)	(14,266,667)	(14,266,667)	(7,133,333)	(185,466,667)
2023	(192,600,000)				(15,408,000)	(15,408,000)	(15,408,000)	(15,408,000)	(15,408,000)	(15,408,000)	(15,408,000)	(15,408,000)	(15,408,000)	(15,408,000)	(15,408,000)	(15,408,000)	(7,704,000)	(184,896,000)
2024	(192,600,000)					(16,747,826)	(16,747,826)	(16,747,826)	(16,747,826)	(16,747,826)	(16,747,826)	(16,747,826)	(16,747,826)	(16,747,826)	(16,747,826)	(16,747,826)	(8,373,913)	(184,226,087)
2025	(192,600,000)						(18,342,857)	(18,342,857)	(18,342,857)	(18,342,857)	(18,342,857)	(18,342,857)	(18,342,857)	(18,342,857)	(18,342,857)	(18,342,857)	(9,171,429)	(183,428,571)
2026	(192,600,000)							(20,273,684)	(20,273,684)	(20,273,684)	(20,273,684)	(20,273,684)	(20,273,684)	(20,273,684)	(20,273,684)	(20,273,684)	(10,136,842)	(182,463,158)
2027	(192,600,000)								(22,658,824)	(22,658,824)	(22,658,824)	(22,658,824)	(22,658,824)	(22,658,824)	(22,658,824)	(22,658,824)	(11,329,412)	(181,270,588)
2028	(192,600,000)									(25,680,000)	(25,680,000)	(25,680,000)	(25,680,000)	(25,680,000)	(25,680,000)	(25,680,000)	(12,840,000)	(179,760,000)
2029	(192,600,000)										(29,630,769)	(29,630,769)	(29,630,769)	(29,630,769)	(29,630,769)	(29,630,769)	(14,815,385)	(177,784,615)
	(6,741,000,000)	**(166,920,000)**	**(347,122,759)**	**(361,389,425)**	**(376,797,425)**	**(393,545,251)**	**(411,888,109)**	**(432,161,793)**	**(454,820,616)**	**(480,500,616)**	**(510,131,385)**	**(510,131,385)**	**(510,131,385)**	**(510,131,385)**	**(510,131,385)**	**(510,131,385)**	**(255,065,693)**	(6,741,000,000)

PACIFIC GAS AND ELECTRIC COMPANY
2023 General Rate Case Phase I
Application 21-06-021
Data Response

PG&E Data Request No.:	TURN_061-Q07		
PG&E File Name:	GRC-2023-PhI_DR_TURN_061-Q07		
Request Date:	November 23, 2021	Requester DR No.:	TURN-PG&E-61
Date Sent:	December 9, 2021	Requesting Party:	The Utility Reform Network
PG&E Witness:	Paul Hunt Jack Battin	Requester:	Hayley Goodson

SUBJECT: WORKING CASH (PG&E EXHIBIT 10-R, CH. 14)

Questions refer to PG&E-10-R, Chapter 14 unless otherwise indicated.

QUESTION 07

On p. 14-9, line 15, PG&E states that "there are years in which PG&E's consolidated tax group will pay no income taxes, for various reasons."

a. Does PG&E expect that it will pay cash federal income taxes during the 2023 GRC period?

b. If the answer to part (a) above is anything other than an unqualified "no," please give the year during the 2023 GRC cycle in which PG&E expects to pay cash federal income taxes.

c. If the answer to part (a) above is anything other than an unqualified "no," please give each and every reason why PG&E expects to pay cash federal income taxes during the 2023 GRC cycle along with supporting documentation as to why this is the case.

d. Does PG&E expect that it will pay cash state income taxes during the 2023 GRC period?

e. If the answer to part (d) above is anything other than an unqualified "no," please give the year during the 2023 GRC cycle in which PG&E expects to pay cash state income taxes.

f. If the answer to part (d) above is anything other than an unqualified "no," please give each, and every reason why PG&E expects to pay cash state income taxes during the 2023 GRC cycle along with supporting documentation as to why this is the case.

ANSWER 07

a. Yes, PG&E expects that it will pay cash federal income taxes during the 2023 GRC period.

b. PG&E expects to pay cash federal income taxes in 2025 and 2026.

c. PG&E expects to pay cash federal income taxes during the 2023 GRC cycle pursuant to Internal Revenue Code section 172(a)(2)(B), which limits federal net operating loss (NOL) deductions to 80% of federal taxable income for carryforward NOL's generated in taxable years beginning after December 31, 2017.
d. No, PG&E does not expect that it will pay cash state income taxes during the 2023 GRC period.
e. n/a
f. n/a

PACIFIC GAS AND ELECTRIC COMPANY
2023 General Rate Case Phase I
Application 21-06-021
Data Response

PG&E Data Request No.:	TURN_151-Q008		
PG&E File Name:	GRC-2023-PhI_DR_TURN_151-Q008		
Request Date:	March 7, 2022	Requester DR No.:	TURN-PG&E-151
Date Sent:	March 21, 2022	Requesting Party:	The Utility Reform Network
PG&E Witness:	Paul Hunt	Requester:	Hayley Goodson

SUBJECT: PG&E-10-R, CHAPTER 14

QUESTION 008

In PG&E-10 E, Chapter 14, Tables 14-3 through 14-6, PG&E gives the following Test year expense amounts for federal and state taxes for use in its lead lag study. TURN has compiled these in the table below for clarity.

Summary of PG&E Estimate Taxes for Lead-Lag Study				
Line #	Department	Federal Income Tax Expense in ($ MM)	State Income Tax Expense in ($MM)	Source
1	Electric Distribution	$ 311.218	$ 96.018	PG&E -10E, p. 14-19, Table 14-3, lines 8 and 9
2	Gas Distribution	$ 97.360	$ 31.155	PG&E -10E, p. 14-22, Table 14-4, lines 8 and 9
3	Gas Transmission	$ 16.378	$ (4.170)	PG&E -10E, p. 14-24, Table 14-5, lines 8 and 8
4	Generation	$ 135.591	$ 53.429	PG&E -10E, p. 14-26, Table 14-6, lines 8 and 9
5	Total Income Taxes	$ 560.547	$ 176.432	Sum of rows 1 through 4

a. Referring to the Summary above is this PG&E's current estimate of test year state and federal taxes for the purposes of its Working Cash lead-lag study? If the figures above are incorrect, please provide the correct figures.

b. If the figures summarized from PG&E-10 E, Chapter 14 are correct, please describe and explain each and every reason why they do not match the income tax figures provided in PG&E-10 E, Chapter 13, Figure 13-1. Please provide supporting documentation.

ANSWER 008

a. The figures above are not correct. The correct figures are shown in this table:

Corrected Summary of PG&E Estimated Income Tax Expense for Lead-Lag Study				
Line #	Department	Federal Income Tax Expense in ($ MM)	State Income Tax Expense in ($ MM)	Source
1	Electric Distribution	311.218	97.847	PG&E -10E, p. 14-19, Table 14-3, lines 8 and 9
2	Gas Distribution	96.018	31.155	PG&E -10E, p. 14-22, Table 14-4, lines 8 and 9
3	Gas Transmission	16.378	(4.170)	PG&E -10E, p. 14-24, Table 14-5, lines 8 and 8
4	Generation	135.591	53.429	PG&E -10E, p. 14-26, Table 14-6, lines 8 and 9
5	Total Income Taxes	559.205	178.261	Sum of rows 1 through 4

b. The figures in line 5 of the corrected summary shown above do not match income tax figures in PG&E-10E, Chapter 13, Figure 13-1 because they match income tax figures in PG&E-10E, Chapter 13, Figure 13-2 at line 43, column E for federal income tax expense and at line 25, column E, for state income tax expense.

   Federal and state income tax expenses will change based on the decision adopted in the 2023 GRC.

PACIFIC GAS AND ELECTRIC COMPANY
2023 General Rate Case Phase I
Application 21-06-021
Data Response

PG&E Data Request No.:	TURN_061-Q03		
PG&E File Name:	GRC-2023-PhI_DR_TURN_061-Q03		
Request Date:	November 23, 2021	Requester DR No.:	TURN-PG&E-61
Date Sent:	December 15, 2021	Requesting Party:	The Utility Reform Network
PG&E Witness:	Paul Hunt	Requester:	Hayley Goodson

SUBJECT: WORKING CASH (PG&E EXHIBIT 10-R, CH. 14)

Questions refer to PG&E-10-R, Chapter 14 unless otherwise indicated.

QUESTION 03

Referring to Exhibit PG&E-10-R Chapter 14, Working Cash, Goods and Services Expense Lag, WP p. 14-130, PG&E calculates a total Goods and Services Expense Lag of 16.55. Please provide the Goods and Services Expense Lag for each year 2017, 2018, 2019, 2020 broken out by PO and Non-PO invoices.

ANSWER 03

Please see the attachment GRC-2023-PhI_DR_TURN_061-Q03Atch01.xlsx.

PG&E is not able to provide the information broken out by PO and non-PO invoices.

Pacific Gas and Electric Company
2023 General Rate Case
Exhibit PG&E-10, Chapter 14, Working Cash
Goods and Services Expense Lag
Data Request TURN_061, Q3

Line No.		2017	2018	2019	2020
1	Days Between Invoice Date and Payment Clearing Date	13.92	16.35	23.57	17.21
2	(Less) Average Number of Days Between Invoice Date and Received Date	0.69	0.70	0.74	0.71
3	Percentage of Materials Bought Within California	60%	58%	53%	57%
4	Average Transit Time Within California	1.5	1.5	1.5	1.5
5	Percentage of Materials Bought Outside California	40%	42%	47%	43%
6	Average Transit Time Outside California	4.5	4.5	4.5	4.5
7	Product Procurement Factor	0.256	0.256	0.256	0.256
8	Total Days Lag (Line 1 minus Line 2)	13.24	15.65	22.82	16.49

PACIFIC GAS AND ELECTRIC COMPANY
2023 General Rate Case Phase I
Application 21-06-021
Data Response

PG&E Data Request No.:	TURN_061-Q04		
PG&E File Name:	GRC-2023-PhI_DR_TURN_061-Q04		
Request Date:	November 23, 2021	Requester DR No.:	TURN-PG&E-61
Date Sent:	December 9, 2021	Requesting Party:	The Utility Reform Network
PG&E Witness:	Paul Hunt	Requester:	Hayley Goodson

SUBJECT: WORKING CASH (PG&E EXHIBIT 10-R, CH. 14)

Questions refer to PG&E-10-R, Chapter 14 unless otherwise indicated.

QUESTION 04

Referring to Exhibit PG&E-10-R Chapter 14, Working Cash, Goods and Services Expense Lag, WP p. 14-130:

a. Please explain why PG&E uses 2017 data to calculate the average number of days between invoice date and received date.

b. Please provide all calculations and assumptions supporting PG&E's figure of 0.66 days.

ANSWER 04

a. An analysis using year 2020 data was not conducted prior to the 2023 GRC filing so PG&E reproduced the calculation provided in the prior GRC. Although the workpaper indicates that the calculation was based on 2017 data, it now appears that is not correct, as the calculation is essentially unchanged from PG&E's workpapers in the 2014 GRC; the 2014 GRC workpaper indicates that 2011 data were used at that time.

   Using 2020 data on the split between purchases within California and purchases outside of California, PG&E updates the calculation as shown in GRC-2023-PhI_DR_TURN_061-Q04Atch01.xlsx. PG&E will include this update in a future errata.

b. The calculations and assumptions are contained within WP p. 14-130 note 2, lines 8 through 18.

PACIFIC GAS AND ELECTRIC COMPANY
2023 General Rate Case Phase I
Application 21-06-021
Data Response

PG&E Data Request No.:	TURN_151-Q002		
PG&E File Name:	GRC-2023-PhI_DR_TURN_151-Q002		
Request Date:	March 7, 2022	Requester DR No.:	TURN-PG&E-151
Date Sent:	March 21, 2022	Requesting Party:	The Utility Reform Network
PG&E Witness:	Paul Hunt	Requester:	Hayley Goodson

SUBJECT: PG&E-10-R, CHAPTER 14

QUESTION 002

Please explain and describe each and every way PG&E's bankruptcy in 2020 impacted the payment terms and arrangements it has with its vendors. Please provide supporting documentation

ANSWER 002

PG&E filed for Bankruptcy on January 29, 2019.

PG&E's Chapter 11 filing triggered an "automatic stay", or an injunction, that prevented anyone from collecting debts owed by the company prior to the Chapter 11 filing date of January 29, 2019. As a result, PG&E was required to separate its outstanding obligations as either Pre-Petition (before the filing date) or Post-Petition (on or after the filing date).

For Pre-Petition invoices incurred for goods and services before the filing date of January 29, 2019, the Chapter 11 filing prohibited PG&E from paying them, unless authorized pursuant to an Order entered by the Bankruptcy Court. The expectation was that those invoices for goods and services would be resolved when the bankruptcy process concluded. (See response to GRC-2023-PhI_DR_TURN_151-Q003).

Post-Petition invoices incurred for goods and services after the filing date of January 29, 2019, were paid according to payment terms and normal course of business.

PACIFIC GAS AND ELECTRIC COMPANY
2023 General Rate Case Phase I
Application 21-06-021
Data Response

PG&E Data Request No.:	TURN_151-Q003		
PG&E File Name:	GRC-2023-PhI_DR_TURN_151-Q003		
Request Date:	March 7, 2022	Requester DR No.:	TURN-PG&E-151
Date Sent:	March 21, 2022	Requesting Party:	The Utility Reform Network
PG&E Witness:	Paul Hunt	Requester:	Hayley Goodson

SUBJECT: PG&E-10-R, CHAPTER 14

QUESTION 003

If the impacts described in Question 2, have been mitigated by PG&E's emergence from bankruptcy, please describe and explain each and every way the emergence from bankruptcy has impacted the payment terms and arrangements that PG&E has with its vendors. Please provide supporting documentation.

ANSWER 003

Pre-Petition invoices that were resolved and settled within the bankruptcy claims / contract cure process have been paid in full with post-petition interest in accordance with the Plan of Reorganization (or are in the process of settlement for anticipated payment).

Post-Petition invoices have continued to be paid according to payment terms and normal course of business.

PACIFIC GAS AND ELECTRIC COMPANY
2023 General Rate Case Phase I
Application 21-06-021
Data Response

PG&E Data Request No.:	TURN_151-Q005		
PG&E File Name:	GRC-2023-PhI_DR_TURN_151-Q005		
Request Date:	March 7, 2022	Requester DR No.:	TURN-PG&E-151
Date Sent:	March 21, 2022	Requesting Party:	The Utility Reform Network
PG&E Witness:	Paul Hunt	Requester:	Hayley Goodson

SUBJECT: PG&E-10-R, CHAPTER 14

QUESTION 005

If the answer to question 4 above is "yes" that PG&E did not include Goods and Services payments by credit card in its lead lag study, please provide

a. the total of all goods and services paid by credit card in each year 2018, 2019, 2020, and 2021.

ANSWER 005

a. See table below for goods and services paid by credit card for 2018 through 2021:

Year	Credit Card Payments
2018	$176,364,115
2019	$195,492,663
2020	$187,432,283
2021	$192,346,189

PUBLIC ADVOCATES OFFICE (Cal Advocates)
DATA RESPONSE
Pacific Gas & Electric Company Test Year 2023 General Rate Case
A.21-06-021

Date: 29 June 2022

Origination Date: 17 June 2022

Response Due: 01 July 2022

To: Hannah Keller, PG&E Discovery Manager
HXKY@pge.com
cc: GRC@pge.com

GRC 2023 Coordinators:
Rachel Keller, Victoria Anes, Gissell Morales,
Maria Osorio, and Sharh Phung

From: Tamera Godfrey, Project Coordinator
Public Advocates Office
505 Van Ness Avenue, Room 4104
San Francisco, CA 94102 tamera.godfrey@cpuc.ca.gov

Data Request No: GRC-2023-PhI_DR_PGE_CalAdvocates003

GENERAL OBJECTIONS

Cal Advocates objects to each data request to the extent that it mischaracterizes Cal Advocates' opening testimony.

Cal Advocates objects to each data request to the extent that it is overly broad, unduly burdensome, or not reasonably calculated to lead to the discovery of admissible evidence.

Cal Advocates objects to each instruction and data request as overly broad and unduly burdensome to the extent that it seeks documents or information that PG&E will possess when it receives Cal Advocates' opening testimony. Responding to such requests would be oppressive, unduly burdensome, and unnecessarily expensive, and the burden of responding to such requests is substantially the same or less for PG&E as for Cal Advocates. All such documents and information will not be produced.

Cal Advocates objects to each instruction and data request to the extent that it seeks information or documents protected from disclosure by the attorney-client privilege, attorney work product doctrine, or any other applicable privilege.

PG&E Question 1:

On page 3 at lines 18 and 19, Public Advocates' testimony states: "Remove the bank lag of 0.13 days …" On page 34 at lines 9 through 11, Public Advocates' testimony states: "The Commission should therefore adopt the recommended bank lag days of 0.13 days …" Which of these is Public Advocates' recommendation with respect to bank lag? Please state all facts that support your position.

Public Advocates Office Response to Question 1:

The text on page 34 is correct; Cal Advocates will issue an errata regarding the text on page 3. Cal Advocates discusses the facts supporting its position in Ex. CA-15, page 33, line 24 through page 34, line.11. The calculation of the $8.5 million adjustment is shown in Cal Advocates' Excel workpaper tab 3.a.

Response prepared by Truman Burns.

PG&E Question 2:

At page 10, lines 7 through 9, Public Advocates' testimony discusses customer advances and states: "The electric distribution and gas distribution rate base is reduced by the average customer advance balance."

a. Footnote 26 refers to changes in utility plant forecasts. Is footnote 26 correct?
b. If the answer to part a of this question is affirmative, please explain why the footnote is correct.
c. If the answer to part a of this question is negative, please provide the correct text for footnote 26.

Public Advocates Office Response to Question 2:

a. Yes.
b. Footnote 26 is discussing how Cal Advocates' other witnesses recommendations have an impact on utility plant forecasts.
c. Not applicable.

Response prepared by Truman Burns.

PG&E Question 3:

At page 10, lines 7 through 9, Public Advocates' testimony discusses customer advances and states: "The electric distribution and gas distribution rate base is reduced by the average customer advance balance." At page 10, lines 10 through 15, Public Advocates' testimony discusses customer deposits.

a. Is it Public Advocates' contention or belief that customer advances and customer deposits are the same thing?

b. If the answer to part a of this question is affirmative, please explain why customer advances and customer deposits are the same.

c. If the answer to part a of this question is negative, please provide

   Public Advocates' understanding of the differences between customer advances and customer deposits.

Public Advocates Response to Question 3:

a. No.
b. Not applicable.
c. PG&E requires customer advances for construction (CAC) when it extends utility services to new customers; customer advances may be refunded in whole or in part in accord with PG&E's tariffs. Customer deposits have been required to establish or reestablish service, as security for the payment of bills.

Response prepared by Truman Burns.

PG&E Question 4:

This question pertains to the FERC Uniform System of Accounts (USOA).

a. Do you agree that with respect to the FERC Uniform System of Accounts (USOA) that the following accounts are not the same: accounts 235 (customer deposits) and accounts 252 (customer advances for construction)?

Public Advocates Office Response to Question 4:

Yes.

Response prepared by Truman Burns.

PG&E Question 5:

At page 10, lines 16 through 18, Public Advocates' testimony states that PG&E's total working cash capital is $1.677 billion, with $1,058 million related to PG&E's lead lag study, and $618 million for operational cash requirements.

a. As these figures do not match PG&E's errata testimony or associated workpapers submitted on February 28, 2022, please provide a copy of the document from which these figures were taken and state when and how it was provided to Public Advocates.
b. Based on PG&E's errata testimony and associated workpapers submitted on February 28, 2022, does Public Advocates agree that the correct figures are as follows: total working cash, $1.682 billion; $1.071 billion related to PG&E's lead lag study; and $611 million for operational cash requirements.
c. If the answer to part b of this question is negative, please provide all facts to explain why Public Advocates believes that is the correct answer.

Public Advocates Office Response to Question 5:

a. This is most likely a Cal Advocates textual error related to PG&E errata spreadsheet Ex.10-Ch.14-WP-Confidential, November 2021 errata.
b. Yes.
c. Not applicable.

Response prepared by Truman Burns.

PG&E Question 6:

At page 30, Public Advocates' testimony discusses D.20-06-003 and Resolution M-4849 and appears to claim that Resolution M-4849 ends the bar on PG&E collecting customer deposits to establish or reestablish service.

a. Is the above statement an accurate description of Public Advocates' contention?
b. Please cite the specific language in Resolution M-4849 that ends the bar on PG&E collecting customer deposits to establish or reestablish service.

Public Advocates Office Response to Question 6:

a. Yes.
b. Ordering Paragraph 1 of Resolution M-4849 states on page 33:

1. Electric, gas, communications, and water corporations subject to this Resolution shall continue to apply the customer protection measures for residential and small business customers adopted in D.19-07-015 and D.19-08-025, as ordered by Resolution M-4842, through June 30, 2021.

Response prepared by Truman Burns.

PG&E Question 7:

At page 32, lines 8 through 9, Public Advocates' testimony cites numbers for expense lag and revenue lag, and the difference between the expense lag and revenue lag.

a. Please confirm that the expense lag of 34.75 days pertains only to the calculation of the working cash requirement from the lead-lag study for PG&E's Electric Generation.
b. Please confirm that the difference between the expense lag and the revenue lag of 13.90 days pertains only to the working cash requirement from the lead-lag study for PG&E's Electric Generation.
c. Please confirm that the figures of 34.75 days and 13.90 days are found in PG&E's original testimony submitted on June 30. 2021 and are not found in the corresponding Table 14-6 in Exhibit PG&E-10 of PG&E's errata and supplemental testimony submitted on February 28, 2022.

Public Advocates Office Response to Question 7:

a. Confirmed.
b. Confirmed.
c. Confirmed.

Response prepared by Truman Burns.

PG&E Question 8:

Please provide all workpapers and any other supporting documents associated with the calculation of the $124.09 million number found in line 22 on page 32 of Exhibit CA-15.

Public Advocates Office Response to Question 8:

The calculation is performed in footnote 87 on page 32 of Ex. CA-15.

Response prepared by Truman Burns.

PG&E Question 9:

At lines 13 through line 18 [Ex. CA-15, p. 33], Public Advocates' testimony states as follows: "However, by changing the tax payment date from the forecasted payment date (as per IRS) to an internally forecasted lag-day, PG&E forecasts a shorter expense lag resulting in an increase of working cash capital amount collected from ratepayers. By doing this, PG&E increases its cash flow for taxes that are not going to be paid at the end of the day. PG&E is violating the "rate-neutral" approach that the Commission ordered PG&E to follow while handling the wildfire claims collection and NOL treatment."

a. Please provide all workpapers and any other supporting documents associated with the text cited above.

b. Please cite with specificity those parts of D.21-04-030 and D.21-05- 011 the Public Advocates believes are violated by PG&E's calculation of the income tax expense lags in this application.

Public Advocates Office Response to Question 9:

a. There are no workpapers or supporting documents associated with the quoted text.
b. As discussed in D.21-04-030, PG&E's wildfire recovery bond proposal was premised on rate neutrality. (D.21-04-030, pp. 41, 62 (footnote 241), 67, 68, 72, 82 and 83). The Commission adopted PG&E's wildfire recovery bond proposal in D.21-04-030, including rate neutrality. PG&E's GRC proposal to have a shorter tax expense lag results in an increase in working cash, which would be collected from ratepayers. The increased expense would not be rate neutral. Furthermore, given PG&E's NOL situation, the taxes would not be paid at the end of the day. The reference on p. 33 of Ex. CA-15 to D.21-05-011 originated with PG&E's testimony (Ex. PG&E-10, p. 14-12, 11-5-2021), but does not appear to be relevant.

Response prepared by Truman Burns.

PACIFIC GAS AND ELECTRIC COMPANY
2023 General Rate Case Phase I
Application 21-06-021
Data Response

PG&E Data Request No.:	CalAdvocates_016-Q01		
PG&E File Name:	GRC-2023-PhI_DR_CalAdvocates_016-Q01		
Request Date:	August 6, 2021	Requester DR No.:	PubAdv-PG&E-016-ANU
Date Sent:	August 20, 2021	Requesting Party:	Public Advocates Office
PG&E Witness:	Ned W. Allis (subparts a, b, f, and g) Beatrix Greenwell (subparts c, d, f, and g) Pei Sue Ong (subparts c, d and e)	Requester:	Truman Burns

SUBJECT: CHAPTER 12 – DEPRECIATION AND NET SALVAGE

FERC Account 362 – Station Equipment (Electric Plant)

QUESTION 01

Referring to Exhibit PG&E-10, workpaper titled "GRC-2023-PhI_Test_PGE_20210630_660514 WP PG&E-10, 4 of 6," pp. WP 12-511 to WP 12-524, please answer the following questions:

a. Referring to p. WP 12-513, update and provide separate graphs for each row of survivor curve group listed below along with the original curves. Label and identify all survivor curves in the graphs.

Row No.	Survivor Curve Group
1	48-R0 ; 48-R1 ; 48-R1.5 ; 48-R2 ; 48-R2.5
2	49-R0 ; 49-R1 ; 49-R1.5 ; 49-R2 ; 49-R2.5
3	50-R0 ; 50-R1 ; 50-R1.5 ; 50-R2 ; 50-R2.5
4	51-R0 ; 51-R1 ; 51-R1.5 ; 51-R2 ; 51-R2.5
5	52-R0 ; 52-R1 ; 52-R1.5 ; 52-R2 ; 52-R2.5
6	53-R0 ; 53-R1 ; 53-R1.5 ; 53-R2 ; 53-R2.5
7	50-L1 ; 50-R1.5 ; 50-R1 ; 50-R1.5 ; 50-S1 ; 50-S1.5

b. Calculate and provide "composite remaining life" for each of the survivor curve mentioned in the table above.

c. Referring to p. WP 12-520, does PG&E estimate "regular retirements" for the forecasted Test Year (TY) 2023?

d. If yes, explain in detail how PG&E estimates "regular retirements" and show the calculations with dollar amount for TY 2023.

e. Referring to p. WP 12-520, does PG&E estimate any extra-ordinary retirements that are not accounted for the in TY 2023 estimate?

f. Referring to p. WP 12-520, provide detailed recorded transactions for the “cost of removal” from recorded years 2016 to 2020 in MS Excel with all formulas intact.

g. Referring to p. WP 12-520, provide detailed recorded transactions for the “gross salvage” from recorded years 2016 to 2020 in MS Excel with all formulas intact.

ANSWER 01

a. Please see GRC-2023-PhI_DR_CalAdvocates_016-Q01Atch01 through GRC-2023-PhI_DR_CalAdvocates_016-Q01Atch07 for the requested information. Please note that the lowest mode R curve is the R0.5. Accordingly, the R0.5 has been graphed instead of an R0.

b. As discussed and agreed upon at the August 13, 2021 meeting between PG&E and Cal Advocates, PG&E will provide calculations of composite remaining lives once Cal Advocates has reviewed the graphs provided in subpart a of this response and has selected curves for composite remaining life calculations.

c. The depreciation study in Exhibit (PG&E-10), Chapter 12 is not the source of forecast retirements in test year 2023. Exhibit (PG&E-10), Chapters 10 and 11 provide the forecasting in the 2023 GRC of “regular” retirements, which are termed normal retirements.

d. Exhibit (PG&E-10), Chapter 10, Section F testimony describes that normal retirements represent assets that are forecast to be retired from service and replaced with new assets. There is a correlation between gross plant additions and the amount of plant removed (i.e. retired) from service for a given asset. This correlation is represented by a ratio derived for each functional group of assets based on recorded retirements as a percentage of recorded gross additions. This ratio was used to forecast normal retirements by applying the ratio against forecasted plant additions.

e. Please see Exhibit (PG&E-10), Chapter 11, WP Table 11-44, Retirement Factors (Retirements as a % of Gross Additions) for the calculation of the ratios. The asset class ratios were applied against asset class gross additions to determine the forecast normal retirements. Forecast 2023 EOY normal retirements and 2023 WAVG normal retirements are provided in Exhibit (PG&E-10), Chapter 10, WP Tables 10-41 and 10-48, respectively.

f. The depreciation study in Exhibit (PG&E-10), Chapter 12 is not the source of forecast retirements in test year 2023. Exhibit (PG&E-10), Chapter 10, Section F testimony describes the forecasting of major retirements in the 2023 GRC. PG&E is forecasting major retirements for Diablo Canyon (Unit 1 in 2024, Unit 2 in 2025) and the sale of its San Francisco General Office (SFGO) in 2021. The retirement of SFGO was reflected as an adjustment to (i.e. removed from) the recorded 2020 end of year plant.

g. As discussed and agreed upon at the August 13, 2021 meeting between PG&E and Cal Advocates, for each of the requested nine FERC accounts for years 2016-2020, PG&E is providing in excel the recorded cost of removal (COR) detail to support the depreciation study workpaper amounts by asset class, planning order, and major work category (MWC). Also included in the depreciation study amounts are cost of removal journal entries that were recorded in years 2016 through 2020 at the asset class level but were not yet recorded to the Plant subledger (i.e. PowerPlant tool) and thus aren't available at an order level of detail.

Please see attachments GRC-2023-PhI_DR_CalAdvocates_016-Q01Atch08 through GRC-2023-PhI_DR_CalAdvocates_016-Q01Atch12, which provide the requested information for the nine FERC plant accounts for years 2016 through 2020:

2016 - attachment GRC-2023-PhI_DR_CalAdvocates_016-Q01Atch08
2017 - attachment GRC-2023-PhI_DR_CalAdvocates_016-Q01Atch09
2018 - attachment GRC-2023-PhI_DR_CalAdvocates_016-Q01Atch10
2019 - attachment GRC-2023-PhI_DR_CalAdvocates_016-Q01Atch11
2020 - attachment GRC-2023-PhI_DR_CalAdvocates_016-Q01Atch12

<u>Electric Plant Accounts</u>:
362 (Station Equipment)
364 (Poles, Towers and Fixtures)
365 (Overhead Conductors and Devices)
367 (Underground Conductors and Devices)
368 (Line Transformers – Overhead)
<u>Gas Plant Accounts</u>:
367 (Transmission Mains)
376 (Distribution Mains)
380 (Distribution Services)
<u>Common Plant Account</u>:
390 (Structures and Improvements)

h. As discussed and agreed upon at the August 13, 2021 meeting between PG&E and Cal Advocates, for each of the requested nine FERC accounts for each year 2016-2020, PG&E is providing in excel the recorded monthly and year total gross salvage amounts by asset class that support the depreciation study workpapers. Please see attachment GRC-2023-PhI_DR_CalAdvocates_016-Q01Atch13.

<u>Electric Plant Accounts</u>:
362 (Station Equipment)
364 (Poles, Towers and Fixtures)
365 (Overhead Conductors and Devices)
367 (Underground Conductors and Devices)
368 (Line Transformers – Overhead)
<u>Gas Plant Accounts</u>:
367 (Transmission Mains)
376 (Distribution Mains)
380 (Distribution Services)
<u>Common Plant Account</u>:
390 (Structures and Improvements)

PACIFIC GAS AND ELECTRIC COMPANY

APPENDIX C

GRC-2023-PHI_DR_CALADVOCATES_016-Q01ATCH08

THIS ATTACHMENT IS AVAILABLE ELECTRONICALLY AS AN EXCEL DUE TO THE SIZE. PLEASE SEE ZIP FILE "EXHIBIT 23 APPENDIX C – DISCOVERY ATTACHMENTS" ON PG&E'S PUBLIC CASE DOCUMENT SITE

PACIFIC GAS AND ELECTRIC COMPANY

APPENDIX C

GRC-2023-PHI_DR_CALADVOCATES_016-Q01ATCH09

THIS ATTACHMENT IS AVAILABLE ELECTRONICALLY AS AN EXCEL DUE TO THE SIZE. PLEASE SEE ZIP FILE "EXHIBIT 23 APPENDIX C – DISCOVERY ATTACHMENTS" ON PG&E'S PUBLIC CASE DOCUMENT SITE

PACIFIC GAS AND ELECTRIC COMPANY

APPENDIX C

GRC-2023-PHI_DR_CALADVOCATES_016-Q01ATCH10

THIS ATTACHMENT WILL BE AVAILABLE ELECTRONICALLY UPON REQUEST DUE TO THE SIZE. IT ALSO AVAILABLE ON PG&E'S PUBLIC DISCOVERY PORTAL

PACIFIC GAS AND ELECTRIC COMPANY

APPENDIX C

GRC-2023-PHI_DR_CALADVOCATES_016-Q01ATCH11

THIS ATTACHMENT IS AVAILABLE ELECTRONICALLY AS AN EXCEL DUE TO THE SIZE. PLEASE SEE ZIP FILE "EXHIBIT 23 APPENDIX C – DISCOVERY ATTACHMENTS" ON PG&E'S PUBLIC CASE DOCUMENT SITE

PACIFIC GAS AND ELECTRIC COMPANY

APPENDIX C

GRC-2023-PHI_DR_CALADVOCATES_016-Q01ATCH12

THIS ATTACHMENT IS AVAILABLE ELECTRONICALLY AS AN EXCEL DUE TO THE SIZE. PLEASE SEE ZIP FILE “EXHIBIT 23 APPENDIX C – DISCOVERY ATTACHMENTS” ON PG&E’S PUBLIC CASE DOCUMENT SITE

PACIFIC GAS AND ELECTRIC COMPANY
2023 General Rate Case Phase I
Application 21-06-021
Data Response

PG&E Data Request No.:	CalAdvocates_052-Q08		
PG&E File Name:	GRC-2023-PhI_DR_CalAdvocates_052-Q08		
Request Date:	September 1, 2021	Requester DR No.:	PubAdv-PG&E-052-ANU
Date Sent:	September 15, 2021	Requesting Party:	Public Advocates Office
PG&E Witness:	Pei Sue Ong/Beatrix Greenwell (a) and (b) Beatrix Greenwell/Maria Ly/David Carroll (c) Beatrix Greenwell/Marcus Wendler (d) Beatrix Greenwell/Josh Jones (e)	Requester:	Anusha Nagesh

SUBJECT: FOLLOW UPS TO DR-015-ANU AND DR-016-ANU, CHAPTERS 14 AND 16

Follow-up to DR-016-ANU, Q.1 to Q.9, cost of removal

QUESTION 08

Referring to PG&E's response to data request PubAdv-PG&E-016-ANU, in documents titled "GRC-2023-PhI_DR_CalAdvocates_016-Q01Atch08," "GRC-2023-PhI_DR_CalAdvocates_016-Q01Atch09," "GRC-2023-PhI_DR_CalAdvocates_016-Q01Atch10," "GRC-2023-PhI_DR_CalAdvocates_016-Q01Atch11," and "GRC-2023-PhI_DR_CalAdvocates_016-Q01Atch12," answer the following questions:

a. Explain in detail how and where in workpapers does PG&E record cost of removal of properties retired due to wildfires before being placing in service in years 2016 to 2020, if any.

b. Explain in detail how and where in workpapers does PG&E record cost of removal of properties in service that are retired due to wildfires in years 2016 to 2020.

c. Referring to tab "EDP36200" in all documents, explain in detail why costs related to "install" and "emergency" are recorded in cost of removal in years 2016 to 2020?

d. Referring to tabs "EDP36400," "EDP36500," and "EDP36801" in all documents, explain in detail why costs related to "CEMA" and "MEBA" are included in cost of removal recorded in years 2016 to 2020?

e. Referring to tabs "EDP36500" and "EDP36801" in all documents, explain in detail why costs related to "Standard NEM," "Expanded NEM" and "Aggregate NEM" are included in cost of removal recorded in years 2016 to 2020?

ANSWER 08

a. Wildfire related removal cost is recorded the same way as non-wildfire related removal costs. As described in Exhibit (PG&E-10), Chapter 10, section E, footnote 13, cost of removal is considered a capital expenditure. Cost of removal reflects the costs to retire an asset being replaced or retired. Capital expenditures generally include costs that are recorded to both capital additions and accumulated depreciation. In accordance with the FERC USOA Account 108, Accumulated Provision for Depreciation of Utility Plant guidelines, account 108 shall be charged with the cost of removal for the retirement of a plant asset. As described in Exhibit (PG&E-10), Chapter 10, section E, footnote 14, for recorded costs, consistent with FERC plant instruction No. 11, PG&E tracks the costs of its construction projects by work orders. The costs of work orders which have an estimated construction of less than 30 days are transferred to plant-in-service on a monthly basis. For work orders estimated to have construction periods of 30 days or greater, the costs, net of any cost of removal are accumulated in CWIP and transferred to plant-in-service once the work order becomes operational (i.e.,used and useful). The removal costs associated with the retired assets are recorded as a reduction ("debit") to accumulated depreciation in the period incurred on all capital orders. The majority of PG&E's removal work is associated with asset replacement work that includes the installation of a new asset and retirement/ removal of an existing asset. As such, the expenditures incurred by PG&E to remove assets are charged to work orders which settle to (are charged to) removal cost in the accumulated depreciation reserve. Cost of removal incurred related to wildfires from 2016-2020 is included in the recorded accumulated depreciation balance[1] as of December 31, 2020, which is the last recorded year. See Exhibit (PG&E-10), Chapters 11, Depreciation Reserve and Expense and Chapter 15, Electric & Gas Distribution, Electric Generation, GT&S Rate Base for recorded 2020 accumulated depreciation balances.[2]

b. See the response to subpart a.

c. See the response to subpart a. Most of PG&E's capital removal work is incurred in conjunction with an asset replacement. The cost of removal represents a portion of the total costs of the referenced projects related to the removal the old asset. Costs incurred to remove the existing/old assets are recorded as a "debit" to accumulated depreciation. As such, planning orders with a general description of asset "install" usually include the removal cost of an existing asset as well. For example, MWC 09 Electric Distribution Automation (DA) and Protection includes capital expenditure for installing new and replacing obsolete substation automation equipment and deficient protective relays (as described at Exhibit (PG&E-4, Chapter 16). The same applies to emergency asset replacement such as orders under MWC 59 Distribution Substation Emergency Equipment Replacement (as described at Exhibit (PG&E-4), Chapter 15). MWC 59 comprises replacement of equipment that has failed in

1 See CalAdvocates_052-Q12 and CalAdvocates_052-Q14 for a discussion of journal entries related to the disallowance of wildfire related costs.

2 See for example, Exhibit (PG&E-10), Chapter 11 WP Table 11-16 Depreciation Reserve EOY by Unbundled Cost Category – Years 2020 through 2023, and Exhibit (PG&E-10), Chapter 15, Table 15-3, Recorded 2020 Weighted Average Rate Base by UCC, line 18.

service, as well as replacement of equipment intentionally removed from service (or "forced out") because PG&E has determined that imminent failure is likely to occur.

d. The removal related work and cost of Catastrophic Emergency Memorandum Account (CEMA) and Major Emergency Balancing Account (MEBA) events are recorded the same as all other electric distribution properties. The purpose of the CEMA account is to allow utilities to record for eventual recovery the reasonable costs they incur in restoring service, repairing or replacing facilities, and complying with government orders following a catastrophic event, declared by the State of California. Similarly, the purpose of MEBA is to recover actual expenses and capital revenue requirements resulting from responding to major emergencies and catastrophic events not eligible for recovery through CEMA. When a major emergency happens, it causes outages and/or imminent hazards to the electric distribution facilities that require immediate action to repair or replace facilities and restore service, but essentially these jobs are replacement jobs as described above. As described in response to subpart a, the same order includes both the cost to remove the old/existing asset and to install the new asset.

e. The removal work related to Net Energy Metering (NEM), "Standard NEM," "Expanded NEM" and "Aggregate NEM" is recorded to asset classes EDP36500 (Overhead Conductors/Devices) and EDP36801 (Overhead Line Transformers) is recorded the same as all other electric distribution properties. Standard NEM represents solar and wind energy programs for customers whose generator size is 30 kilowatts or less. Expanded NEM represents solar and wind energy programs for Agricultural and Demand Rate customers whose generator is of any size and for Residential and Small Commercial rate customers whose generator capacity is over 30 kilowatts. PG&E's Net Energy Metering Aggregation (NEMA) program is designed to benefit a single customer with multiple eligible meters on the same property, or on adjacent or contiguous properties; NEMA enables one renewable generation system, such as solar technology, to serve the energy needs (aggregated load) of multiple eligible meters. NEM projects fall under MWC 10 Electric Work at the Request of Others as described at Exhibit (PG&E-4, Chapter 18). NEM projects may include, among other activities, the installation of a new panel or meter, a new Transformer, interconnection to PG&E facilities, and the installation of new dedicated service and may include removal of old/existing equipment. As described in subpart a, for replacement work, removal work is followed with the replacement of the asset, and order costs include both the cost to remove the old/existing asset and to install the new asset. The jobs that include replacement can also incur cost of removal as described above. The same order includes both the cost to remove the old/existing asset and to install the new asset.

PACIFIC GAS AND ELECTRIC COMPANY
2023 General Rate Case Phase I
Application 21-06-021
Data Response

PG&E Data Request No.:	CalAdvocates_052-Q012		
PG&E File Name:	GRC-2023-PhI_DR_CalAdvocates_052-Q012		
Request Date:	September 1, 2021	Requester DR No.:	PubAdv-PG&E-052-ANU
Date Sent:	September 15, 2021	Requesting Party:	Public Advocates Office
PG&E Witness:	Beatrix Greenwell (a) Mark Esguerra (b)	Requester:	Anusha Nagesh

SUBJECT: FOLLOW UPS TO DR-015-ANU AND DR-016-ANU, CHAPTERS 14 AND 16

Follow-up to DR-016-ANU, Q.1 to Q.9, cost of removal

QUESTION 012

Referring to PG&E's response to data request PubAdv-PG&E-016-ANU, in the documents titled "GRC-2023-PhI_DR_CalAdvocates_016-Q01Atch11" and "GRC-2023-PhI_DR_CalAdvocates_016-Q01Atch12," answer the following questions:

a. Referring to tab "EDP36400," explain in detail why costs related to "WILDFIRE OII COST OF REMOVAL WRITE-OFF" and "SYSTEM HARDENING COST OF REMOVAL ADJ" are included in cost of removal in years 2019 and 2020?

b. Referring to tab "GTP36700_GTP36703," explain in detail why costs related to "08W-WILDFIRE RESILIENCY" and "MEBA" are included in cost of removal in years 2019 and 2020?

ANSWER 012

a. The cost of removal reflects the costs to retire the existing/old assets from service. The expenditures incurred by PG&E to remove assets are charged to work orders which settle to removal cost in the accumulated depreciation reserve (i.e. recorded as a "debit" to the accumulated depreciation reserve).

   The "WILDFIRE OII COST OF REMOVAL WRITE-OFF" was recorded in the general ledger for the disallowance of costs related to cost of removal. This journal entry is to reflect capital disallowance related to Decision (D.) 20-05-019 related to 2017 and 2018 Wildfires Investigation.

   The disallowance was recorded as a "credit" to the accumulated depreciation reserve in EDP36400 in 2019, to remove these expenditures from accumulated depreciation as part of the disallowance of costs. In 2020 the asset management subsidiary ledger was updated for the disallowance, and the journal entry was reversed as a "debit".

The work orders related to “SYSTEM HARDENING COST OF REMOVAL ADJ” did not have the cost of removal defined in the asset management subsidiary ledger at the order level and the costs remained in Construction Work in Progress (CWIP). A journal entry was recorded to reclassify a portion of the costs incurred for the removal of existing/old assets that are reflected in CWIP to Cost of Removal in order for CWIP balances to be correctly stated at the end of the year.

b. PG&E interprets the request is referring to electric accounts, not gas transmission GTP36700_GTP36703, with the terms “08W-WILDFIRE RESILIIENCY” and “MEBA”. The removal work of “08W-WILDFIRE RESILIENCY” is recorded to asset classes EDP36400, EDP36500, EDP36700, and EDP36801 and is recorded the same as all other electric distribution properties. MAT 08W (System Hardening) work is described at Exhibit (PG&E-4, Chapters 4.3 and 13). Projects may include, among other activities, line removal, remote grid, underground conversion from overhead, relocation of overhead facilities, and hardening overhead in place. Hardening overhead in place includes the installation of covered conductor, intumescent wrapped wood poles or composite poles, replacement of non-exempt equipment, replacement of transformers that do not have the now standard FR3 insulating fluid, composite crossarm, framing, and other animal/bird protections. The cost of removal represents a portion of the total costs of the referenced projects incurred for the physical removal the old asset. Costs of removing the existing/old assets are recorded as a “debit” to the accumulated depreciation reserve in the years for which the costs were incurred. For “MEBA”, refer to data response CalAdvocates_052-Q012d.

PACIFIC GAS AND ELECTRIC COMPANY
2023 General Rate Case Phase I
Application 21-06-021
Data Response

PG&E Data Request No.:	CalAdvocates_052-Q014		
PG&E File Name:	GRC-2023-PhI_DR_CalAdvocates_052-Q014		
Request Date:	September 1, 2021	Requester DR No.:	PubAdv-PG&E-052-ANU
Date Sent:	September 15, 2021	Requesting Party:	Public Advocates Office
PG&E Witness:	Beatrix Greenwell	Requester:	Anusha Nagesh

SUBJECT: FOLLOW UPS TO DR-015-ANU AND DR-016-ANU, CHAPTERS 14 AND 16

Follow-up to DR-016-ANU, Q.1 to Q.9, cost of removal

QUESTION 014

Referring to PG&E's response to data request PubAdv-PG&E-016-ANU, in the documents titled "GRC-2023-PhI_DR_CalAdvocates_016-Q01Atch12," answer the following questions:

a. Referring to tab "GTP36700_GTP36703," explain in detail why costs related to "2011-2014 GT&S COST OF REMOVAL PUSHED DOWN TO SUBLEDGER" are included in cost of removal in year 2020?
b. Referring to tabs "GDP38000" and "CMP39000," explain in detail why costs related to "WILDFIRE OII COST OF REMOVAL WRITE-OFF" and "PLANT TO COST OF REMOVAL RECLASS" are included in cost of removal in year 2020?
c. Referring to tab "GDP38000" explain in detail why costs related to "Catastrophic Events" are included in cost of removal in year 2020?

ANSWER 014

a. As discussed in CalAdvocates_052-Q08 subpart a, the cost of removal reflects the costs to retire or remove the existing/old asset from service. The expenditures incurred by PG&E to remove assets are charged to work orders which settle to removal cost in the accumulated depreciation reserve (i.e. recorded as a "debit" to the accumulated depreciation reserve).

   The "2011-2014 GT&S COST OF REMOVAL PUSHED DOWN TO SUBLEDGER" represents the reversal of a capital disallowance journal entry which was recorded in the general ledger during 2016 related to the 2015 GT&S decision (D.16-06-056), now pushed down to the asset management system (subledger) at the order level during 2020. The disallowance required PG&E to remove the total capital expenditure amount, including both plant and COR, from rate base. The 2020 journal entry, when combined with the earlier 2016 journal entry nets to zero, with this adjustment now reflected in the subledger.

b. See CalAdvocates_052-Q012 subpart a. The same accounting applies to GDP38000 as EDP36400.

   For CMP39000, the work orders related to “PLANT TO COST OF REMOVAL RECLASS” did not have the cost of removal defined in the asset management system at the order level and the costs remained in plant. A journal entry was recorded to reclass the costs from plant to cost of removal in order to correctly state the plant balance at the end of the year.

c. As discussed in CalAdvocates_052-Q08 subpart a, the cost of removal reflects the cost of removal work incurred to retire an asset. The expenditures incurred by PG&E to remove assets are charged to work orders which settle to removal cost, when incurred, in the accumulated depreciation reserve. The planning orders related to “Catastrophic Events” in tab “GDP38000” for year 2020 represent costs to retire and remove old assets and replace them with new assets. The work performed is the replacement and installation of new gas service lines (full service) typically from the premise to the underground main. The cost of removal represents a portion of the total costs of the referenced projects related to the removal of the old assets. Costs incurred to remove the existing/old assets are recorded as a “debit” to accumulated depreciation.

PACIFIC GAS AND ELECTRIC COMPANY
2023 General Rate Case Phase I
Application 21-06-021
Data Response

PG&E Data Request No.:	CalAdvocates_083-Q06		
PG&E File Name:	GRC-2023-PhI_DR_CalAdvocates_083-Q06		
Request Date:	September 24, 2021	Requester DR No.:	PubAdv-PG&E-083-ANU
Date Sent:	October 22, 2021	Requesting Party:	Public Advocates Office
PG&E Witness:	Beatrix Greenwell Pei Sue Ong	Requester:	Anusha Nagesh

SUBJECT: CHAPTERS 14, 12, FOLLOW-UP TO DR-016-ANU, DR-045-ANU, AND DR-052-ANU

QUESTION 06

Referring to PG&E's response to data request PubAdv-PG&E-016-ANU, Q.1, in the document titled "GRC-2023-PhI_DR_CalAdvocates_016-Q01Atch08," tab EDP36200, cell G382, please answer the following questions:

a. Provide a copy of all invoices or supporting documents for the total amount.

b. Provide an Excel spreadsheet listing all invoice numbers, corresponding amount and calculate the total amount to match the amount in Cell G382.

ANSWER 06

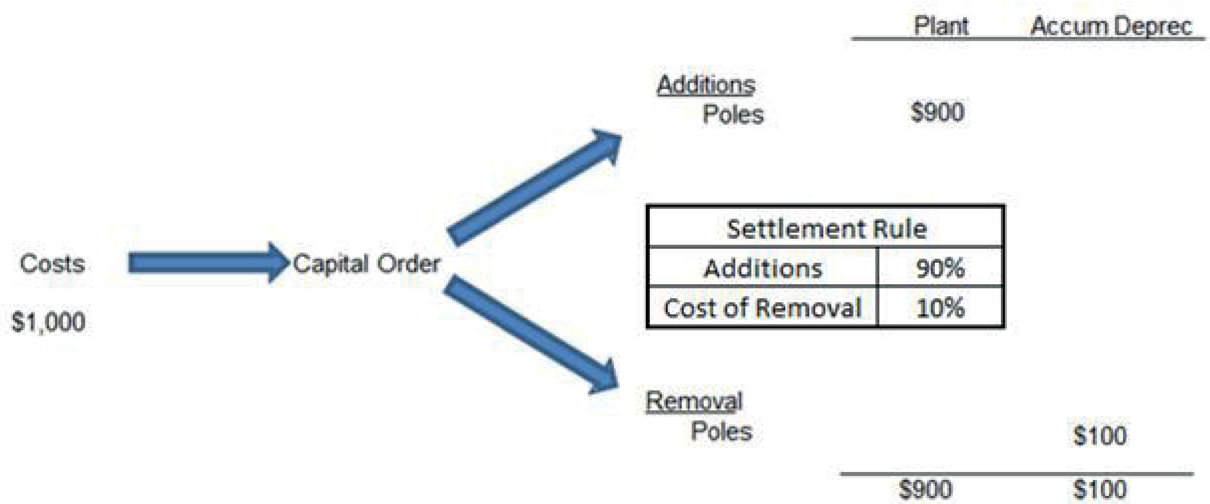
a. Cost of removal is not recorded at an invoice or other supporting document level of detail. Capital expenditures are generally available at that level of detail.

   Please see the response to GRC-2023-PhI_DR_CalAdvocates 083-Q07 for a description of PG&E's process to segregate capital costs between cost of removal and installation using the settlement rules process. Additional information is added below, including the specific request in this Question 06 on the $3,293,729 cost of removal amount in cell G382 of tab EDP36200 pertaining to year 2016 in the document titled "GRC-2023-PhI_DR_CalAdvocates_016-Q01Atch08".

   PG&E prepares a job estimate for each capital project in accordance with its capital guidelines. For projects with removal costs (i.e., the removal of existing facilities or equipment), the job estimate includes estimated costs for installation and removal of the existing facilities/equipment based on the activities to be performed on the project. As actual capital expenditures are incurred, installation costs are recorded as a debit (increase) to FERC Account 107 (construction work in progress). These costs will eventually be recorded to FERC Account 101 (plant in service) based on the operative date for the project. Removal costs are recorded as a debit (decrease) to FERC Account 108 (accumulated depreciation). The actual cost of removal of the existing facilities/equipment is determined by applying the cost of removal percentage (estimated removal costs over total estimated project costs) from the job estimate to the actual capital expenditures incurred on the project.

- Capital job estimates are updated periodically when there are changes to the scope of the construction project. Settlement rules in PowerPlan are updated accordingly when there are updates to job estimates.

Below is a diagram depicting how settlement rules direct capital expenditure costs to the fixed asset subledger (PowerPlan).



Regarding the specific request for Cell G382, the recorded cost of removal amount pertains to capital job order under planning order 5767700. The removal % provided in this job estimate is 1.79% which is calculated in the job estimate property settlement sheet as a ratio of estimated removal costs divided by (estimated removal costs + property installation costs).

The invoices and other documentation supporting the actual costs incurred in this job has over 17,000 line items. Please note that costs incurred for this order span from years 2015 through 2019. The $3.3 million in cell G382 was largely reversed, leaving a recorded cost of removal amount of $254 thousand for this order.

b. See GRC-2023-PhI_DR_CalAdvocates_083-Q06Atch01.xlsx for the cost details for order 74001604, which support planning order 5767700. As discussed in subpart a., these cost items including invoices will not directly tie to the amount in cell G382.

PACIFIC GAS AND ELECTRIC COMPANY

APPENDIX C

GRC-2023-PHI_DR_CALADVOCATES_083-Q06ATCH01

THIS ATTACHMENT IS AVAILABLE ELECTRONICALLY AS AN EXCEL DUE TO THE SIZE. PLEASE SEE ZIP FILE “EXHIBIT 23 APPENDIX C – DISCOVERY ATTACHMENTS” ON PG&E’S PUBLIC CASE DOCUMENT SITE

PACIFIC GAS AND ELECTRIC COMPANY
2023 General Rate Case Phase I
Application 21-06-021
Data Response

PG&E Data Request No.:	CalAdvocates_083-Q07		
PG&E File Name:	GRC-2023-PhI_DR_CalAdvocates_083-Q07		
Request Date:	September 24, 2021	Requester DR No.:	PubAdv-PG&E-083-ANU
Date Sent:	October 8, 2021	Requesting Party:	Public Advocates Office
PG&E Witness:	Beatrix Greenwell Pei Sue Ong	Requester:	Anusha Nagesh

SUBJECT: CHAPTERS 14, 12, FOLLOW-UP TO DR-016-ANU, DR-045-ANU, AND DR-052-ANU

QUESTION 07

Referring to PG&E's responses to data request PubAdv-PG&E-052-ANU, Q.8, Q.12.b, Q.13 and Q14.c, please answer the following questions:

a. Do costs related to "install" include costs of removal and replacement or installation costs?

b. Explain in detail PG&E's process to segregate costs to cost of removal and installation related for accounting purposes.

ANSWER 07

a. Only replacement jobs will include cost of removal. Jobs with install only will not include cost of removal.

b. PG&E utilizes capital job estimates to develop the accounting settlement rules or unit estimates, which are assigned to capital orders within the PowerPlant system (i.e. Fixed-Asset Subledger). Settlement rules direct order costs to the appropriate asset records within Plant in Service, and to the appropriate removal and salvage records within accumulated depreciation, and also provide the parameters for retiring asset records

   Please refer to Section 3 of PG&E's Capital Job Estimate Standard, provided in GRC-2023-PhI_DR_TURN_026Q17Atch06, for the description of PG&E's process to segregate capital costs between cost of removal and installation using the settlement rules process (extract below):

   3. Settlement Rules

   3.1 Capital project costs must be segregated between the costs incurred to install new property (i.e., plant additions) and the costs incurred to remove old property (i.e., cost of removal).

3.2 Capital project costs must be categorized and summarized into the asset classes and components that are applicable to the property installed and removed.

3.3 Capital project costs must be segregated into the asset locations where the assets are installed and removed.

3.4 Settlement rules for each capital order must be input into PowerPlant so that project costs are assigned to asset records based on allocation percentages that are computed in the job estimate.

3.5 Settlement rules for each capital order which installs or removes “mass” assets (i.e., asset classes/components that are retired using quantities) must input into PowerPlant the quantities of assets that are installed or retired.

3.6 Settlement rules for each capital order which removes or abandons assets must input into PowerPlant the parameters for retiring the cost of the assets from the accounting records.

.

Pacific Gas and Electric Company®

Capital Job Estimate Standard

SUMMARY

This standard establishes the enterprise-wide accounting framework for property, plant and equipment (PP&E), issued by PG&E Corporation and its affiliates and subsidiaries, including Pacific Gas and Electric Company. This standard provides the requirements and responsibilities related to job estimates and order settlement rules.

It is important that these requirements and responsibilities be adhered to, in order to diminish the risks related to expending funds on capital projects without approved job estimates. The following are financial risks related to improper job estimate preparation and approval:

1. Capital orders without approved job estimates may result in the following:
   a. Unauthorized capital expenditures
   b. Misstatement of plant balances
   c. Regulatory disallowances
   d. Other legal damages
2. Capital orders without proper settlement rules (unit estimates) may result in misstatements of the following:
   a. Plant and accumulated depreciation balances
   b. Depreciation expense
   c. Recovery of costs from incorrect customers
3. Capital orders without proper settlement rules (unit estimates) may delay the timely transfer of costs from construction work in progress (CWIP) to plant and result in operative CWIP and the over-accrual of an Allowance for Funds Used During Construction (AFUDC).

TARGET AUDIENCE

All PG&E employees with responsibilities related to capital project job estimates and settlement rules; including the following specific tasks:

- Planning or managing capital projects
- Preparing or approving job estimates
- Entering order settlement rules into the PowerPlant system

Capital Job Estimate Standard

TABLE OF CONTENTS

REQUIREMENTS

1 Capital Expenditures Authorization

1.1 Capital expenditures must be approved in accordance with PM-1001P-01 Project Approval Procedure and PM-1004S Project Delegation of Authority Standard.

1.2 Planned capital expenditures (non-emergency work) require an authorized job estimate before construction costs[1] are incurred, with the following exceptions:

1. Planned capital expenditures for work which is ongoing, routine, scheduled and relatively low costs can be approved using the Standing Capital Order Authorization Form in accordance with FIN-3808S Standing Capital Orders Standard.

2. Categories of planned capital expenditures which are tracked in specific orders (i.e., non-standing orders), and which can be safely and properly constructed without pre-engineering or estimating, may be exempted from the requirement for an authorized job estimate prior to the construction start date if an exception request is approved by Capital Accounting.

   a. Exception requests must be submitted annually using Attachment 1 - Job Estimate Exemption Request Form and approved by Capital Accounting.

   b. Categories of planned capital expenditures which are exempted from requiring approval prior to the construction date must be documented and approved "after-the-fact" using a job estimate (i.e., post-estimate).

      (1) See Appendix 1 for a list of the planned work categories exempted from pre-job estimates.

1.3 Unplanned capital expenditures, which are incurred to address emergencies and which cannot be approved before construction costs are incurred, must be documented and approved "after-the-fact" using a job estimate (i.e., post-estimate).

[1] For substation projects involving both civil and electrical construction, the job estimate must be approved before electrical construction begins.

Capital Job Estimate Standard

2 Job Estimate Template

2.1 Each operating department is responsible for utilizing a standard job estimate template that has been approved by Capital Accounting and meets the following requirements:

1. Job estimate templates must contain the following sheets as described in this Step:

   a. Face Sheet

   b. Detail Sheet

   c. Summary Sheet

   d. Property, Settlement Sheet

2. Job estimate templates must contain a "Face Sheet" which documents:

   a. Management's approval of the total gross authorized project cost, including the following cost components:

      (1) All direct costs that are documented in the "Detail Sheet" per Step 3 below.

      (2) All overhead costs that are computed in the "Summary Sheet" per Step 4 below.

      (3) Contingency that is computed in accordance with PM-1005S Project Cost Estimating Standard.

   b. A narrative description of the project scope and justification.

   c. The duration of the construction period (Start Date and Operative Date) which is used to determine the order type (type 60 or 70) and AFUDC rate in accordance with FIN-3804S Allowance for Funds Used During Construction (AFUDC) Standard.

   d. The location of the construction work where assets are installed or removed.

   e. The SAP capital order master data fields per FIN-3806S Capital Orders - SAP and PowerPlant System Requirements, including the following:

      (1) Planning order

      (2) Major work category (MWC)

      (3) Main activity type (MAT)

      (4) Receiver cost center (RCC)

Capital Job Estimate Standard

3. Job estimate templates must contain a “Detail Sheet” which documents the detailed list of resources (i.e., labor, materials, contracts, etc.) to be expended and activities (i.e., engineering, construction, testing, etc.) to be performed to install and/or remove assets per the projects’ approved scope of work. Each detailed line item must:

    a. Include the estimated direct costs of the resource/activity using current unit prices for labor, materials and other cost elements, in accordance with PM-1005S Project Cost Estimating Standard.

    b. Indicate whether the resource/activity relates to the installation of new assets, the removal of old assets, or is common to both installation and removal.

    c. Identify the specific asset class and component that are assignable to the resource/activity per the settlement rules guidelines in Section 3 below, or indicate that the resource/activity is common to multiple asset classes and components.

        (1) The asset class/component assignments for all categories of resources/ activities that listed in the Detail Sheet must be pre-approved by Capital Accounting. Each operating department must have formal procedures to ensure that new resources/activities (e.g., new material codes) are reviewed by Capital Accounting for proper accounting assignments.

4. Job estimate templates must contain a “Summary Sheet” which summarizes the direct costs from the Detail Sheet by primary cost element (internal services, materials, contracts, other, etc.) and computes the estimated indirect and overhead costs in a manner consistent with the actual indirect and overhead calculations in SAP.

    a. Estimated overheads must be computed using the latest composite overhead rates that are maintained by Cost Model Governance in the Cost Model Overhead Planning Template.

    b. Estimated Allowance for Funds Used During Construction (AFUDC) must be computed in accordance with FIN-3804S – Attachment 1, AFUDC Application Factor.

    c. Costs must be escalated to reflect inflation in accordance with Attachment 2 – Escalation Instructions.

5. Job estimate templates must contain a “Property, Settlement Sheet” which documents the settlement rules for entry into PowerPlant. The settlement rules must document the following (refer to Section 3 for additional requirements):

    a. Estimated costs to install each asset record per the approved project scope.

    b. Estimated costs to remove each asset record per the approved project scope.

    c. Parameters for retiring each asset record per the approved project scope.

2.2 Attachment 3 – Sample Job Estimate contains a sample job estimate template which complies with the requirements of this standard.

3 Settlement Rules

3.1 Capital project costs must be segregated between the costs incurred to install new property (i.e., plant additions) and the costs incurred to remove old property (i.e., cost of removal).

3.2 Capital project costs must be categorized and summarized into the asset classes and components that are applicable to the property installed and removed.

1. Asset classes represent groups of long-lived assets which collectively perform a unique utility function and which are assigned a single depreciation life. Asset classes correspond with the plant accounts that are prescribed in the FERC Uniform System of Accounts (USOA).

   - FERC USOA defines the types of equipment and costs that are includible in each plant account.

2. Asset components are subsets of asset classes which provide more detailed information than is required by the FERC USOA for plant accounts. PG&E uses asset components primarily to facilitate asset retirements and tax reporting.

3.3 Capital project costs must be segregated into the asset locations where the assets are installed and removed.

1. Asset locations are defined as the combination of the receiver cost center, county and specific facility identification. Asset locations are used primarily to facilitate property tax and property insurance calculations, as well as asset retirements.

3.4 Settlement rules for each capital order must be input into PowerPlant so that project costs are assigned to asset records based on allocation percentages that are computed in the job estimate.

1. Settlement rules must be documented in the job estimate "Property, Settlement Sheet".

2. Each settlement rule line item must identify the estimated project costs to install or remove plant components, as identified by a capital asset record which consists of an asset class, asset component and asset location (per Sections 3.2 and 3.3 above).

3. The estimated project costs to install and remove each asset record must be computed in the job estimate using the following approach:

   a. Identify the capital retirement units to be installed and removed.

   b. Determine the asset class, component and asset location that are assignable to each of the capital retirement units in accordance with the FERC USOA and the Retirement Unit Catalog.

Capital Job Estimate Standard

3.4 (continued)

c. Identify the estimated costs to directly install or remove the capital retirement units and assign those costs to the applicable asset class, component and asset location.

d. Identify the estimated costs that are common to multiple retirement units (e.g., project management, engineering, mapping, overheads) and spread those costs to the asset classes, components and asset locations associated with the retirement units using an equitable allocation method.

3.5 Settlement rules for each capital order which installs or removes "mass" assets (i.e., asset classes/components that are retired using quantities) must input into PowerPlant the quantities of assets that are installed or retired.

1. Attachment 4 – PowerPlant - SAP Applet Job Aid provides a listing of the "mass" asset classes and components which require quantities in the settlement rules.

3.6 Settlement rules for each capital order which removes or abandons assets must input into PowerPlant the parameters for retiring the cost of the assets from the accounting records.

1. Attachment 4 – PowerPlant - SAP Applet Job Aid provides the guidelines for entering settlement rules in PowerPlant to ensure that assets are properly retired.

4 Operating Department Responsibilities

4.1 Each operating department is responsible for issuing and complying with procedures which are designed to complete job estimates in accordance with this standard.

1. Each operating departments' job estimate procedures must ensure that:

a. Job estimates are prepared using the latest approved version of the job estimate template.

(1) Job estimate templates should be stored electronically in a designated location (e.g., Share Point site) with formal version control.

b. Modifications to the job estimate template, including the addition of new resources/activities (e.g., material codes) to the Detail Sheet, are reviewed and approved by a governance team which consists of experts from the operating department and Capital Accounting.

c. Job estimates are prepared in compliance with the requirements of Section 2 and Section 3 above.

d. Settlement rules are entered into PowerPlant soon after the job estimate is approved.

END of Requirements

Capital Job Estimate Standard

DEFINITIONS

Allowance for Funds used During Construction (AFUDC): Capitalized financing costs that are recorded in CWIP during the period when new plant assets are being constructed (for projects with construction periods greater than 30 days). AFUDC ceases when the assets become operational and transfer from CWIP to plant. AFUDC is recovered in customer rates through depreciation expense. The monthly rates that are used to compute AFUDC reflect PG&E's weighted average cost of capital for both debt and equity. The FERC approves the formula for computing AFUDC, while the CPUC approves the cost of equity rate.

Asset Record: Unique combination of accounting fields which identify an individual asset or group of assets at a level sufficient to meet internal and external reporting requirements. The accounting fields include:

- Asset Class
- Asset Component
- Asset Location
- Vintage (month and year when asset was installed)
- Capital Order

Asset Class: Groups of long-lived assets which collectively perform a unique utility function and which are assigned a single depreciation life. Asset classes correspond with the plant accounts that are prescribed in the FERC Uniform System of Accounts (USOA). The FERC USOA defines the types of equipment and costs that are includible in each plant account. This information is required as part of an asset record.

Asset Component: Subset of asset class which provides more detailed information than is required by the FERC USOA for plant accounts. PG&E uses asset components primarily to facilitate asset retirements and tax reporting.

Asset Location: Combination of the receiver cost center, county and specific facility identification. Asset locations are used primarily to facilitate property tax and property insurance calculations, as well as asset retirements. This information is required as part of an asset record

Asset Retirement: Removal of an asset from the accounting records when it is no longer used and useful. Asset retirements are recorded by removing the original cost of the asset from plant and from accumulated depreciation. Retirements are processed via PowerPlant settlement rules.

Capital Order: Order that tracks all costs (net of billing credits) that are incurred to install and/or remove capital retirement units, which are listed in PG&E's Retirement Units Catalog (RUC). The order settlement rules/unit estimates direct the installation costs to plant accounts and direct the removal costs to accumulated depreciation.

Escalation: Rate that is used only for planning purposes to reflect potential cost increases due to inflation between the time that the job estimate is prepared and when the costs are actually incurred. The rate should be applied and incorporated into capital job estimates when work is estimated to take more than one year to complete.

Capital Job Estimate Standard

Indirect and Overhead Costs: Costs that are allocated to capital orders using a percentage adder (i.e., the overhead rate) that is applied to specified order costs (i.e., the application base).

Operating Department: Internal organizations which are directly involved in the delivery of electric and gas utility services to customers (includes both line and support cost centers within the operating department. This would include departments such as Information Technology (IT), Corporate Real Estate Strategy & Service (CRESS) and Transportation Services/Fleet.

Plant in Service: An account that is used to record the costs of plant assets currently in service. These assets are recorded at their original acquisition or installation cost.

Post-Job Estimate: A job estimate which is prepared ***after*** the construction work is completed. The requirements for such documents are substantially the same as all other job estimates, except that they provide management approval for costs already incurred, not estimated costs. Post-estimates are used only for capital projects which address unplanned emergencies or which have received an exemption from Capital Accounting from the requirement for an authorized job estimate prior to the construction start date.

Removal Cost: The cost of demolishing, dismantling, tearing down or otherwise removing an asset from Plant in Service, including the cost of transportation and handling of above ground equipment.

Retirement Units: Defined in the FERC Uniform System of Accounts (CFR 18, Chapter 1, Part 101 and 201) as “those items of electric/gas plant which, when retired, with or without replacement, are accounted for by crediting the book cost thereof to the electric plant account in which included.” Retirement Units are the lowest level at which PG&E capitalizes an asset.

Settlement Rules / Unit Estimates: Rules which are developed in the job estimate and which are assigned to orders within the PowerPlant system to direct order costs to the appropriate asset records within Plant in Service, and to the appropriate removal and salvage records within accumulated depreciation. Settlement rules also provide the parameters for retiring asset records.

Standing Capital Order: An order that is created to record ongoing, routine, scheduled and relatively low cost capital work. Standing Capital Orders include both type 10 Controlling (CO) capital orders and annual PM capital orders. Costs charged to these orders post directly to Plant in Service, do not reside in CWIP, and do not accrue AFUDC.

IMPLEMENTATION RESPONSIBILITIES

Capital Accounting is responsible for issuing this standard and providing communication, guidance, and training as needed, on the standard to employees who are responsible for planning or managing capital projects, preparing and approving job estimates, and entering order settlement rules into the PowerPlant system.

Capital Job Estimate Standard

Owners of job estimates within the operating departments are responsible for:

1. Issuing, communicating and ensuring compliance with procedures which are designed to complete job estimates in accordance with this standard.
2. Modifying the job estimate template to include the addition of new resources/activities (e.g., material codes), and to consult with Capital Accounting to determine the appropriate settlement rules for the modifications.
3. Training employees within their operating departments on how to prepare and approve job estimates.

Employees within the operating departments are responsible for preparing and approving job estimates and settlement rules in compliance with this standard and department procedures.

GOVERNING DOCUMENT

N/A

COMPLIANCE REQUIREMENT / REGULATORY COMMITMENT

FERC Uniform System of Accounts, 18 CFR, Chapter I, Part 101 Electric Plant Instructions; Part 201 Gas Plant Instructions

Securities Act of 1933

Securities Exchange Act of 1934

REFERENCE DOCUMENTS

Developmental References:

Capital Accounting Instructions

Supplemental References:

FIN-3801S Capital and Expense Standard

FIN-3808S Standing Capital Orders Standard

FIN-3804S Allowance for Funds Used During Construction (AFUDC) Standard

FIN-3806S Capital Orders - SAP and PowerPlant System Requirements

PM-1001P-01 Project Approval Procedure

PM-1004S Project Delegation of Authority Standard

Capital Job Estimate Standard

PM-1005S Project Cost Estimating Standard

Cost Model Overhead Planning Template

Retirement Units Catalog (RUC)

APPENDICES

Appendix 1, Categories of Planned Capital Expenditures Exempted From Pre-Job Estimates

ATTACHMENTS

Attachment 1 - Job Estimate Exemption Request Form

Attachment 2 – Escalation Instructions

Attachment 3 – Sample Job Estimate

Attachment 4 – PowerPlant - SAP Applet Job Aid

DOCUMENT RECISION

N/A

DOCUMENT APPROVER

Chuck Marre, Senior Director, Capital Accounting

DOCUMENT OWNER

Pei Sue Ong, Manager, Capital Accounting Advice

DOCUMENT CONTACT

Thomas Ricci, Principal, Capital Accounting Advice

Jessica Martinez, Expert, Capital Accounting Advice

Weiwen Wang, Expert, Capital Accounting Advice

REVISION NOTES

Where?	What Changed?
N/A	This is a new Standard.

Capital Job Estimate Standard

Appendix 1, Categories of Planned Capital Expenditures Exempted From Pre-Job Estimates

Page 1 of 1

Work Category	Post-Estimate Justification	SAP Identification Codes
1. Grade 1 gas service leak	Work requires immediate response	• MAT Codes: 50G - Improve Reliability / Dependability-Gas Service Replacement Leak • Priority Code: Immediate / Safety

PACIFIC GAS AND ELECTRIC COMPANY
2023 General Rate Case Phase I
Application 21-06-021
Data Response

PG&E Data Request No.:	CalAdvocates_083-Q08		
PG&E File Name:	GRC-2023-PhI_DR_CalAdvocates_083-Q08		
Request Date:	September 24, 2021	Requester DR No.:	PubAdv-PG&E-083-ANU
Date Sent:	October 8, 2021	Requesting Party:	Public Advocates Office
PG&E Witness:	Beatrix Greenwell	Requester:	Anusha Nagesh

SUBJECT: CHAPTERS 14, 12, FOLLOW-UP TO DR-016-ANU, DR-045-ANU, AND DR-052-ANU

QUESTION 08

Referring to PG&E's response to data request PubAdv-PG&E-052-ANU, Q.12.a, please explain in detail why PG&E includes cost of removal which was disallowed for recovery by the Commission in D.20-05-019.

ANSWER 08

As described in PubAdv-PG&E-052-ANU Q.12.a, PG&E's incurred cost of removal was removed from accumulated depreciation (and rate base) in compliance with D.20-05-019. PG&E did not include disallowed cost of removal in the accumulated depreciation. As described in PubAdv-PG&E-052-ANU, Q.12.a, journal entries were made to remove cost of removal capital expenditures from accumulated depreciation.

> The "WILDFIRE OII COST OF REMOVAL WRITE-OFF" was recorded in the general ledger for the disallowance of costs related to cost of removal. This journal entry is to reflect capital disallowance related to Decision (D.) 20-05-019 related to 2017 and 2018 Wildfires Investigation.
> The disallowance was recorded as a "credit" to the accumulated depreciation reserve in EDP36400 in 2019, to remove these expenditures from accumulated depreciation as part of the disallowance of costs.

The following sentence describes the details of implementing the disallowance. What the response said in summary is that the journal entries had net zero impact since it simply moved the disallowance from the journal entry to the subsidiary ledger, with no financial impact to accumulated depreciation due to this move:

> In 2020 the asset management subsidiary ledger was updated for the disallowance, and the journal entry was reversed as a "debit".

PACIFIC GAS AND ELECTRIC COMPANY
2023 General Rate Case Phase I
Application 21-06-021
Data Response

PG&E Data Request No.:	CalAdvocates_083-Q09		
PG&E File Name:	GRC-2023-PhI_DR_CalAdvocates_083-Q09		
Request Date:	September 24, 2021	Requester DR No.:	PubAdv-PG&E-083-ANU
Date Sent:	October 22, 2021	Requesting Party:	Public Advocates Office
PG&E Witness:	Beatrix Greenwell Ned Allis	Requester:	Anusha Nagesh

SUBJECT: CHAPTERS 14, 12, FOLLOW-UP TO DR-016-ANU, DR-045-ANU, AND DR-052-ANU

QUESTION 09

Referring to PG&E's response to data request PubAdv-PG&E-052-ANU, Q.14.a, please provide where in the 2016 workpaper does PG&E include the corresponding journal entry.

ANSWER 09

PG&E assumes that this question is referring to the journal entry discussed in PubAdv-PG&E-052-ANU, Q.14.a, the journal entry which was recorded in the general ledger during 2016 related to the 2015 GT&S (D.16-06-056) disallowance, which was pushed down to the subsidiary ledger in 2020. The response to Q.14a is copied below for reference purposes only.

The corresponding entry from 2016 was not included in the net salvage analysis shown in the workpapers for Chapter 12 of Exhibit (PG&E-10). This entry was not included because the inclusion of the 2016 journal entry reducing cost of removal would result in retirements without cost of removal in the net salvage analysis, which would produce net salvage ratios in the analysis that are not indicative of the costs associating with retiring assets.

ANSWER 014

a. As discussed in CalAdvocates_052-Q08 subpart a, the cost of removal reflects the costs to retire or remove the existing/old asset from service. The expenditures incurred by PG&E to remove assets are charged to work orders which settle to removal cost in the accumulated depreciation reserve (i.e. recorded as a "debit" to the accumulated depreciation reserve).

The "2011-2014 GT&S COST OF REMOVAL PUSHED DOWN TO SUBLEDGER" represents the reversal of a capital disallowance journal entry which was recorded in the general ledger during 2016 related to the 2015 GT&S decision (D.16-06-056), now pushed down to the asset management system (subledger) at the order level during 2020. The disallowance required PG&E to remove the total capital expenditure amount, including both plant and COR, from rate base. The 2020 journal entry, when combined with the earlier 2016 journal entry nets to zero, with this adjustment now reflected in the subledger.

PACIFIC GAS AND ELECTRIC COMPANY
2023 General Rate Case Phase I
Application 21-06-021
Data Response

PG&E Data Request No.:	CalAdvocates_083-Q10		
PG&E File Name:	GRC-2023-PhI_DR_CalAdvocates_083-Q10		
Request Date:	September 24, 2021	Requester DR No.:	PubAdv-PG&E-083-ANU
Date Sent:	October 22, 2021	Requesting Party:	Public Advocates Office
PG&E Witness:	Beatrix Greenwell	Requester:	Anusha Nagesh

SUBJECT: CHAPTERS 14, 12, FOLLOW-UP TO DR-016-ANU, DR-045-ANU, AND DR-052-ANU

QUESTION 10

Referring to PG&E's response to data request PubAdv-PG&E-052-ANU, Q.14.b, please explain in detail how PG&E allocated $4,602,047.03 towards cost of removal. Please provide all supporting documents.

ANSWER 10

As described in PG&E's data response GRC-2023-PhI_DR_CalAdvocates_052-Q014b, a journal entry was recorded to reclassify the costs from plant to cost of removal (COR) in order to correctly state the plant and accumulated depreciation balances at the end of the year. PG&E determined the COR amount by applying a COR percentage to the December 30, 2020 Plant balance. The COR percentage of 5.30% was calculated based on PG&E's 5-year 2015-2019 historical COR percentage compared to capital expenditures as shown below:

Total 2015-2019 Cost of Removal	Total 2015-2019 Capital Expenditure	Percentage
1,603,534	30,282,557	5.30%

The Plant balance of $86,831,076 multiplied by the 5.30% resulted in the $4,602,047 included in PG&E's response to data request PubAdv-PG&E-052-ANU, Q.14.b.

Dec 2020 Plant Balance	5 year avg COR %	Plant to COR reclass
86,831,076	5.30%	4,602,047.03

PACIFIC GAS AND ELECTRIC COMPANY
2023 General Rate Case Phase I
Application 21-06-021
Data Response

PG&E Data Request No.:	CalAdvocates_083-Q12		
PG&E File Name:	GRC-2023-PhI_DR_CalAdvocates_083-Q12		
Request Date:	September 24, 2021	Requester DR No.:	PubAdv-PG&E-083-ANU
Date Sent:	October 22, 2021	Requesting Party:	Public Advocates Office
PG&E Witness:	Beatrix Greenwell, Pei Sue Ong	Requester:	Anusha Nagesh

SUBJECT: CHAPTERS 14, 12, FOLLOW-UP TO DR-016-ANU, DR-045-ANU, AND DR-052-ANU

QUESTION 12

Referring to PG&E's recorded gross-salvage amounts, does the amounts include revenues from trade-ins of old plant to new and re-use of old plant in other location or other line of business, if any? Explain where in the workpapers are these revenues accounted for, if any.

ANSWER 12

The recorded gross salvage amounts do not include revenues from trade-ins of old plant. To our knowledge, PG&E does not perform asset trade-ins on new assets. PG&E does not re-capitalize the reuse of old plant in new locations or lines of business. PG&E uses cradle-to-grave accounting.

PACIFIC GAS AND ELECTRIC COMPANY
2023 General Rate Case Phase I
Application 21-06-021
Data Response

PG&E Data Request No.:	CalAdvocates_113-Q04		
PG&E File Name:	GRC-2023-PhI_DR_CalAdvocates_113-Q04		
Request Date:	October 20, 2021	Requester DR No.:	PubAdv-PG&E-113-ANU
Date Sent:	November 2, 2021	Requesting Party:	Public Advocates Office
PG&E Witness:	Beatrix Greenwell	Requester:	Anusha Nagesh

SUBJECT: CHAPTERS 12, 12A, AND FOLLOW UP TO DATA REQUEST PUBADV-PG&E-083-ANU

Follow-up to data request PubAdv-PG&E-083-ANU.

QUESTION 04

Refer to data request PubAdv-PG&E-083-ANU, Q.08, please answer the following questions:

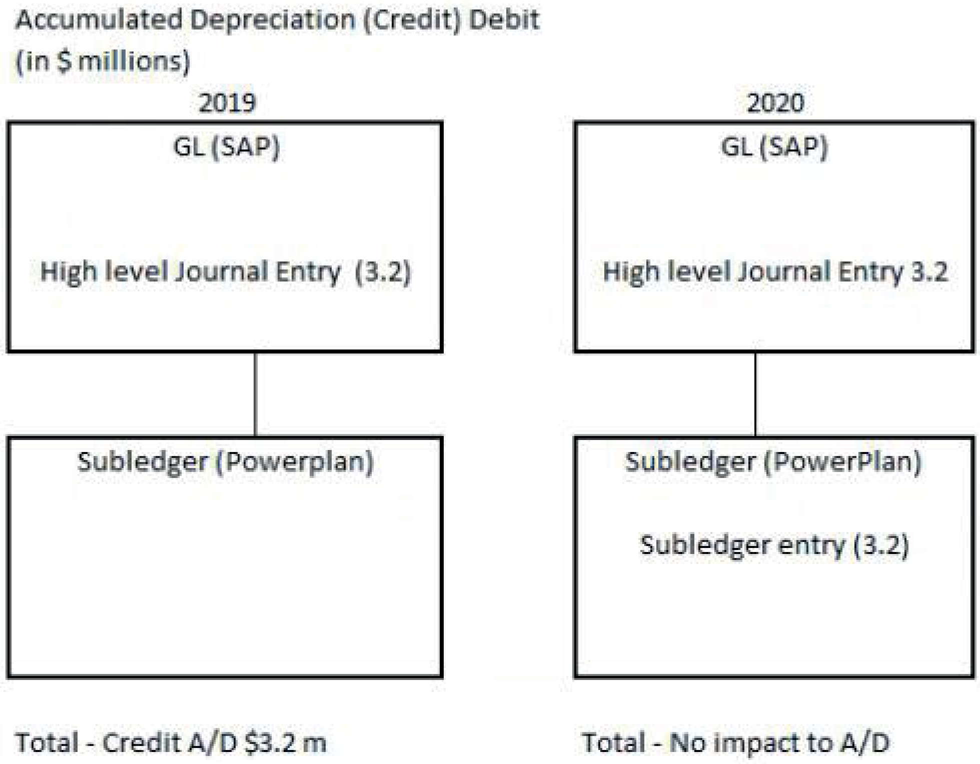
a. The “debit” entry made for correction increased the total recorded cost of removal in year 2020, correct?

b. Please explain reasons why PG&E reversed entry and included in recorded cost of removal after taking out of accumulated depreciation?

ANSWER 04

a. No. The debit journal entry made in 2020 did not increase the total recorded cost of removal in year 2020. The debit journal entry was offset by a credit entry recorded to PG&E’s subledger, netting to zero.

Please see the diagram below that provides the entries and total impact to accumulated depreciation in 2019 and 2020 for account 364.



PG&E first recorded a credit entry of $3.2 million related to the Wildfire OII Cost of Removal Write-off in 2019 (see CalAdvocates_016-Q01Atch11), which reduced cost of removal. This entry was made at a higher level to PG&E's general ledger and was not recorded at the more detailed subledger level. In 2020, PG&E reversed this amount with a debit journal entry of $3.2 million that is included in the $5.1 million provided in GRC-2023-PhI_DR_CalAdvocates_016-Q01Atch12.

b. PG&E did not take the entry out of accumulated depreciation in 2020; the 2020 entry was simply a reclassification from a high-level journal entry to the asset management subsidiary ledger. Please see the response to subpart a.

   For reference purposes only, PG&E is including copies below of the response to PubAdv-PG&E-083-ANU.

Question 08

Referring to PG&E's response to data request PubAdv-PG&E-052-ANU, Q.12.a, please explain in detail why PG&E includes cost of removal which was disallowed for recovery by the Commission in D.20-05-019.

Answer 08

As described in PubAdv-PG&E-052-ANU Q.12.a, PG&E's incurred cost of removal was removed from accumulated depreciation (and rate base) in compliance with D.20-05-019. PG&E did not include disallowed cost of removal in the accumulated depreciation. As described in PubAdv-PG&E-052-ANU, Q.12.a, journal entries were made to remove cost of removal capital expenditures from accumulated depreciation.

> The "WILDFIRE OII COST OF REMOVAL WRITE-OFF" was recorded in the general ledger for the disallowance of costs related to cost of removal. This journal entry is to reflect capital disallowance related to Decision (D.) 20-05-019 related to 2017 and 2018 Wildfires Investigation.
> The disallowance was recorded as a "credit" to the accumulated depreciation reserve in EDP36400 in 2019, to remove these expenditures from accumulated depreciation as part of the disallowance of costs.

The following sentence describes the details of implementing the disallowance. What the response said in summary is that the journal entries had net zero impact since it simply moved the disallowance from the journal entry to the subsidiary ledger, with no financial impact to accumulated depreciation due to this move:

> In 2020 the asset management subsidiary ledger was updated for the disallowance, and the journal entry was reversed as a "debit".

PACIFIC GAS AND ELECTRIC COMPANY
2023 General Rate Case Phase I
Application 21-06-021
Data Response

PG&E Data Request No.:	CalAdvocates_126-Q01		
PG&E File Name:	GRC-2023-PhI_DR_CalAdvocates_126-Q01		
Request Date:	October 28, 2021	Requester DR No.:	PubAdv-PG&E-126-ANU
Date Sent:	November 12, 2021	Requesting Party:	Public Advocates Office
PG&E Witness:	Beatrix Greenwell	Requester:	Anusha Nagesh

SUBJECT: FOLLOW UP TO DATA REQUESTS PUBADV-PG&E-083-ANU, PUBADV-PG&E-052-ANU AND EXHIBITS PG&E-5, CH. 8 AND PG&E-10, CH. 11

QUESTION 01

Referring to data request PubAdv-PG&E-083-ANU, Q.6.a, and Q.10, PG&E explains that cost of removal is a percentage that is applied to capital expenditures. Please answer the following questions:

a. How does PG&E calculate cost of removal percentage for allocation each year? Please explain in detail.

b. Has the Commission in the past approved PG&E's calculation of cost of removal as a percentage of capital expenditures? If yes, provide all Commission decisions.

c. Does PG&E forecast cost of removal for the proposed TY in the GRC? Please explain the response in detail.

ANSWER 01

a. In accordance with the FERC USOA Account 108, Accumulated Provision for Depreciation of Utility Plant guidelines, the expenditures incurred by PG&E to remove assets are charged to work orders which settle to the removal cost subaccount of the accumulated depreciation reserve. Further, these costs settle to the applicable asset classes (i.e., functional plant classification). For recorded cost of removal, PG&E assigns cost of removal, using job estimates as described in GRC-2023-PhI_DR_CalAdvocates_083-Q06. PG&E's accounting policy and procedures can be found in GRC-2023-PhI_DR_TURN_026-Q17.

b. PG&E interprets this question as asking about PG&E's forecasted cost of removal in its rate cases. PG&E has included forecast of cost of removal as a percent of capital expenditures as early as 2011. The current forecast methodology is consistent with the following GRC and GT&S decisions:

Rate Case	Decision
2020 GRC	D.20-12-005
2019 GT&S	D.19-09-025

2017 GRC	D.17-05-013
2015 GT&S	D.16-06-056
2014 GRC	D.14-08-032
2011 GT&S	D.11-04-031
2011 GRC	D.11-05-018

c. Yes. PG&E forecasts cost of removal. Please see Exhibit 10 Chapter 11 Workpaper 11-45 for the forecast removal factors by Asset Class. Cost of removal factors were calculated based on five years of recorded removal costs and capital expenditures.

PACIFIC GAS AND ELECTRIC COMPANY
2023 General Rate Case Phase I
Application 21-06-021
Data Response

PG&E Data Request No.:	CalAdvocates_236-Q001		
PG&E File Name:	GRC-2023-PhI_DR_CalAdvocates_236-Q001		
Request Date:	January 20, 2022	Requester DR No.:	PubAdv-PG&E-236-ANU
Date Sent:	February 9, 2022	Requesting Party:	Public Advocates Office
PG&E Witness:	Beatrix Greenwell (all) Ned Allis (b)	Requester:	Anusha Nagesh

SUBJECT: FOLLOW-UP TO DR-116-ANU, Q.04.F AND Q.02.F (DEPRECIATION STUDY IMPACT)

QUESTION 001

In response to PubAdv-PG&E-016-ANU, Q.04.f, PG&E provided a document titled "GRC-2023-PhI_DR_CalAdvocates_016-Q01Atch12." Refer to tab "GTP36700_GTP36703," cell G710. PG&E includes "2011-2014 GT&S COST OF REMOVAL PUSHED DOWN TO SUBLEDGER" adjustment of -$6,064,949 to cost of removal in recorded year 2020. Answer the following questions:

a. Explain in detail all the transactions in a timeline along with the corresponding dollar amount to show the initial removal entry in cost of removal, corresponding credit entry in rate base and reversal entry in cost of removal for all the impacted recorded years to prove this transaction is not a duplicate entry.

b. With reference to response in Q1.a, explain in detail why each transaction occurred and how it impacts the future net salvage forecast for TY 2023.

c. Identify all journal entries, associated documents in chronological order for this transaction to show the initial removal entry in cost of removal, corresponding credit entry in rate base and reversal entry in cost of removal for all the impacted recorded years corresponding to the amount identified in Q1.a above.

ANSWER 001

a. Please see GRC-2023-PhI_DR_CalAdvocates_236-Q001Atch01, for the requested details to demonstrate that the GT&S cost of removal adjustment of -$6,064,949 is not a duplicate entry.

<u>Overview of Recording Entries</u>:

1. Record amounts to plant and cost of removal (accumulated depreciation) within the subledger (PowerPlan).
2. Commission decision received; PG&E records plant and cost of removal disallowance. Write off estimated capital disallowance to high level general ledger account(s) (SAP).

3. Reverse the disallowance in the high level general ledger account(s) (SAP).
4. Record the disallowance to the individual capital orders within the subledger (PowerPlan).

Detailed Description:

The following is a detailed description of the transactions in the timeline, including references to the attachment for each step.

i. Recorded order costs would exist on the books, including a plant balance and a cost of removal balance. Cost of removal is included in the accumulated depreciation (A/D) balance. These recorded costs would both be debits, or positive amounts which increase rate base.

ii. Upon receiving a Commission decision to disallow plant, record an initial entry per the Commission order to disallow plant and cost of removal. That entry is a credit to the plant and A/D accounts, and a debit to record the loss. The credit entries to plant and A/D reduce rate base. This initial entry is recorded to SAP general ledger accounts and asset classes as estimated initial amounts.
   - Attachment reference: See Tab “1 Summary”, lines 1 and 2. Please refer to column “1080115 Accum Dep- Accrl” for the cost of removal related journal entry amounts. Two initial journal entries totaling the referenced ($6,064,949) were recorded in June 2016 - journal entry 1001919583 in the amount of ($2,328,723) and journal entry 1001919584 in the amount of ($3,736,226).
   - See Tab 3.1 “COR by Asset Class” which provides the high level entry dollar amounts and assigned asset classes. Lines 1 and 2 show the cost of removal disallowance amounts of ($2,328,723) and ($3,736,226) assigned to asset class GTP36700, with a total high level journal entry amount of ($6,064,989).
   - Detailed journal entries have been included as tabs 4-8, with the document number in tab name (see section iii below). See Tab “4 1001919583” and Tab “5 1001919584”. The cost of removal disallowance amounts of ($2,328,723) and ($3,736,226) align with the two disallowance amounts provided in Tab “1, Summary” lines 1 and 2 for these high level journal entries.

iii. Subsequent additions, subtractions and reclassifications may be made based on additional analysis or changing capital order totals, potentially adding to, subtracting from or reclassifying amounts in ii. above.
   - Attachment reference: See Tab “1 Summary”, lines 3-4. Please refer to column “1080115 Accum Dep- Accrl” for the cost of removal related amounts. These subsequent entries were recorded in September and October of 2016.
   - Detailed journal entries have been included as tabs 6-7, with the document number in tab name.

- Attachment reference: The total journal entries for cost of removal can be found in Tab 1, Line 15, column “1080115 Accum Dep-Accrl” as the total high levels of ($6,064,949).

iv. The final stage is to “push down” the entries. What this means is to reverse the high level general ledger entry and replace it with entries in the subledger to specific plant accounts, vintages, etc. The subledger will then contain the disallowance amount. This is essentially a reclassification of where the costs reside.
   - The entries in ii. and iii. are reversed.
     - Attachment reference: See Tab “1 Summary”. Please refer to column “1080115 Accum Dep- Accrl” for the cost of removal related reversal amounts. The total reversal can be found in Line 16 of this column, $6,046,949. The $6,046,949 reversal entry was recorded in October 2020.
     - Note that the line 18 total shows that lines 15 and 17 net to zero.
     - The initial entries in ii. and the reversals in iii. can also be seen in “3.1 COR by Asset Class”.
     - The offset credit is to account 5590049 which functions as a clearing account in conjunction with the subledger.
   - PG&E’s subledger is called PowerPlan. The credits to plant and cost of removal (A/D) are recorded in the subledger. The “push down” to the subsidiary ledger occurred in October 2020.
     - Attachment reference: See tabs “2 COR report by Asset Class” and “3 Order charges report”, line 7, totaling $6,072,893.
     - Because the disallowance is recorded to orders, the final cost of removal amount may differ slightly. In this case, the cost of removal disallowance difference is $7,944.
     - The debit offset is in the subledger and is recorded in account 5590049 which functions as a clearing account

a. PG&E interprets “future net salvage forecast for TY 2023” to be in reference to the net salvage estimates recommended by Mr. Allis in the depreciation study, which will be incorporated into the TY 2023 revenue requirement. Please see Attachment GRC-2023-PhI_DR_CalAdvocates_236-Q001Atch02 for the records from the net salvage data associated with the transactions in Q1.a. The net salvage analysis of historical net salvage data provides statistical support for the future net salvage estimates. If the cost of removal amounts in the analysis include disallowances, this would provide an indication that there are no costs to remove assets (at least for certain projects) and, as a result, the high level adjustment of the disallowance amounts from Q1.a were not included in the net salvage data. PG&E also notes that the overall net salvage in the historical analysis of (149) percent is considerably more negative than the proposed (75) percent net salvage estimate.

b. See the response to subpart a.

GT&S High Level Write Off Journal Entries (General Ledger)
Source: SAP

Line No.	Years	Pstg date	Doc.no.	1010027 Gas Plant Adj	1070028 Corp Adj-Gas CWIP	COR disallowances only - Excludes Deprec Entries 1080115 Accum Dep-Accrl	5040999 Oth Inc/Deds - Misc	5590049 Capital Disallowance	Grand Total	Note
1	**2016**	**Jun**	1001919583	(63,040,282.00)		(2,328,723.00)	65,369,005.00		-	To record disallowance capex of 104 projects per 2015 GT&S decision
2	**2016**	**Jun**	1001919584	(77,134,461.00)		(3,736,226.00)	80,870,687.00		-	To record disallowance capex of small (<$1M) projects per 2015 GT&S decision
3	**2016**	**Sep**	1001961644	(406,192.21)	(84,512.81)	(22,441.72)	513,146.74		-	To record write off incremental capital expenditures to general ledger accounts.
4	**2016**	**Oct**	1001974135	(129,477.42)	84,512.81	22,441.72	22,522.89		-	To reclassify write-off incremental capital expeditures from CWIP and Cost of Removal to Plant to record to general ledger accounts
5	**2016**	**Dec**	1002007677	(73,234.97)			73,234.97		-	To record write off incremental capital expenditures to general ledger accounts.
6	**2017**	**Mar**	1002044131	(99,339.61)			99,339.61		-	To record write off incremental capital expenditures to general ledger accounts.
7	**2017**	**Jun**	1002084607	(56,622.15)			56,622.15		-	To record write off incremental capital expenditures to general ledger accounts.
8	**2017**	**Sep**	1002130636	(59,328.88)			59,328.88		-	To record write off incremental capital expenditures to general ledger accounts.
9	**2017**	**Dec**	1002169149	(18,045.55)			18,045.55		-	To record write off incremental capital expenditures to general ledger accounts.
10	**2018**	**Mar**	1002209125	(11,591.18)			11,591.18		-	To record write off incremental capital expenditures to general ledger accounts.
11	**2018**	**Jul**	1002260095	(15,411.70)			15,411.70		-	To record write off incremental capital expenditures to general ledger accounts.
12	**2018**	**Oct**	1002301575	(460.67)			460.67		-	To record write off incremental capital expenditures to general ledger accounts.
13	**2019**	**Jan**	1002340098	(155.67)			155.67		-	To record write off incremental capital expenditures to general ledger accounts.
14	**2020**	**Jun**	1002602583	(1,034,655.00)			1,034,655.00		-	To record write off incremental capital expenditures to general ledger accounts.
15	**Total high levels before pushdown to subledger**			**(142,079,258)**	**-**	**(6,064,949.00)**	**148,144,207**	**-**	**-**	
16	**2020**	**Oct**	1002651102	142,079,258.01		6,064,949.00		(148,144,207)	-	To reverse write off from general accounts - to be pushed down into the subledger (PowerPlan). See Tab 3. for order pushdown report from PowerPlan.
17	**Reversal of the high levels from general ledger**			**142,079,258**	**-**	**6,064,949.00**	**-**	**(148,144,207)**	**-**	
18	**Ending Net high levels remaining in GL**			**-**	**-**	**-**	**148,144,207**	**(148,144,207)**	**-**	

19 Note: Account 1080115 presented here includes COR write offs only. The depreciation expense reversal is excluded from the information above.

Line No.		1080115	5590049
20	PowerPlan Subledger - See tab 2	6,072,893	(148,144,207)
		(7,944)	-
21	SAP General Ledger - details above	6,064,949	(148,144,207)

Pacific Gas and Electric Company

Cost Of Removal Report

Asset Class		Cost of Removal OCT 2020 - OCT 2020
GDP37601	Distbn Plant: Mains	$ 41,247.28
GTE36800	Trans/PEP: Compressor Station Equipment	$ 12,321.41
GTP36620	Trans Plant: Measrng & Regltng Statn Structr	$ 55,939.58
GTP36630	Trans Plant: Other Structures	$ 144,291.90
GTP36700	Trans Plant: Mains	$ 4,811,258.19
GTP36800	Trans Plant: Compressor Station Equipment	$ 278,668.59
GTP36900	Trans Plant: Measuring & Regulating Station Equipt	$ 559,397.31
GTP37100	Trans Plant: Other Equipment	$ 728.80
GUS35110	UG Stor Plant: Well Structures	$ 3,785.10
GUS35120	UG Stor Plant: Compressor Station Structures	$ 3.42
GUS35200	UG Stor Plant: Wells	$ 74,445.46
GUS35400	UG Stor Plant: Compressor Station Equipment	$ 38,816.23
GUS35500	UG Stor Plant: Measrng & Regultng Statn Eqp	$ 3,849.78
GUS35700	UG Stor Plant: Other Equipment	$ 42,594.48
Overall Result		**$ 6,067,347.53**
Pushdown amount		6,072,893.43
Immaterial variance		5,545.90

Source: PowerPlan
Note: The above amounts represent the credit to A/D in the PowerPlan Subledger, which reduces rate base.
Cost of Removal reductions are show as a positive number in PowerPlan (Subledger) Reports.

Pacific Gas and Electric Company

Order Charges Report

		Amount OCT 2020 - OCT 2020	Amount OCT 2020 - OCT 2020
	Cost Element	5590049	**Overall Result**
G/L Account		Capital Disallowance	
1010120	PISNotClassifie -Gas	(11,033,989.79)	**(11,033,989.79)**
1010130	PISNotClssified-Comm	(263,265.83)	**(263,265.83)**
1010200	PIS -Gas	(130,309,343.66)	**(130,309,343.66)**
1070200	CWIP - Gas	(464,714.30)	**(464,714.30)**
1080005	Accum Depr	(6,072,893.43)	**(6,072,893.43)**
Overall Result		**(148,144,207.01)**	**(148,144,207.01)**

Source: PowerPlan

Note: The above amounts were recorded in PowerPlan in October 2020. (148,144,207) Ties to line 16 on Tab 1

Cost of Removal by Asset Class

Source: SAP

	Sum of Amount		**Asset Class**
Line No.	**Document Numbe**	**Month/Year**	**GTP36700**
1	**1001919583**	06/2016	(2,328,723)
2	**1001919584**	06/2016	(3,736,226)
3	**1001961644**	09/2016	(22,442)
4	**1001974135**	10/2016	22,442
5	**1002651102**	10/2020	6,064,949
6			
7	**Grand Total**		-

Display Document: Data Entry View

Display Currency   General Ledger View

Data Entry View

Document Number	1001919583	Company Code	PGE1	Fiscal Year	2016
Document Date	07/12/2016	Posting Date	06/30/2016	Period	6
Reference		Cross-Comp.No.			
Currency	USD	Texts exist		Ledger Group	

Itm	PK	Account	Description	Order	Oper	Cost Center	Loc.curr.amount	Assignment
1	40	5040999	Oth Inc/Deds - Misc			14769	65,369,005.00	20160630
2	50	1010027	Gas Plant Adj				63,040,282.00-	20160630
3	50	1080115	Accum Dep-Accrl				2,328,723.00-	20160630
4	40	1080001	A/D-Rcls Depr CoRmvl				2,328,723.00	20160630
5	50	2540098	RegLia-ReclsRmvlCost				2,328,723.00-	20160630
6	50	5040999	Oth Inc/Deds - Misc			14769	5,225,554.00-	20160630
7	40	1080115	Accum Dep-Accrl				5,225,554.00	20160630
8	50	1080001	A/D-Rcls Depr CoRmvl				676,523.00-	20160630
9	40	2540098	RegLia-ReclsRmvlCost				676,523.00	20160630

Account 1080115

(2,328,723.00) GT&S Vintage Pipe COR   Gas   HLA reversed via Oct 2020 JE 1002651102

(2,328,723.00) Total Agrees to Summary

Purpose of the Journal Entry:
To record the disallowance of 104 projects per the 2015 GT&S decision effective June 28, 2016 and the related depreciation impact as of June 30, 2016.

Items 1 - 5: To record the etimated capital spending disallowance to Plant and Cost of Removal (COR) and the related reclass of COR remaining in accumulated depreciation to a regulatory liability.

Items 6 - 9: To record the depreciation impact as a result of plant disallowance the the related true down of COR spend.

(PG&E-23)

Display Document: Data Entry View

Display Currency   General Ledger View

Data Entry View

Document Number	1001919584	Company Code	PGE1	Fiscal Year	2016
Document Date	07/12/2016	Posting Date	06/30/2016	Period	6
Reference		Cross-Comp.No.			
Currency	USD	Texts exist		Ledger Group	

Itm	PK	Account	Description	Order	Oper	Cost Center	Loc.curr.amount	Assignment
1	40	5040999	Oth Inc/Deds - Misc			14769	80,870,687.00	20160630
2	50	1010027	Gas Plant Adj				77,134,461.00-	20160630
3	50	1080115	Accum Dep-Accrl				3,736,226.00-	20160630
4	40	1080001	A/D-Rcls Depr CoRmvl				3,736,226.00	20160630
5	50	2540098	RegLia-ReclsRmvlCost				3,736,226.00-	20160630
6	50	5040999	Oth Inc/Deds - Misc			14769	6,572,427.00-	20160630
7	40	1080115	Accum Dep-Accrl				6,572,427.00	20160630
8	50	1080001	A/D-Rcls Depr CoRmvl				768,550.00-	20160630
9	40	2540098	RegLia-ReclsRmvlCost				768,550.00	20160630

Account 1080115
(3,736,226.00) GT&S Vintage Pipe COR   Gas   HLA reversed via Oct 2020 JE 1002651102

(3,736,226.00) Total Agrees to Summary

Purpose of the Journal Entry:
To record the disallowance of $80M in small (<$1M) projects per the 2015 GT&S decision effective June 28, 2016 and the related depreciation impact as of June 30, 2016.

Items 1 - 5: To record the etimated capital spending disallowance to Plant and Cost of Removal (COR) and the related reclass of COR remaining in accumulated depreciation to a regulatory liability.

Items 6 - 9: To record the depreciation impact as a result of plant disallowance the the related true down of COR spend.

Display Document: Data Entry View

Display Currency | General Ledger View

Data Entry View

Document Number	1001961644	Company Code	PGE1	Fiscal Year	2016
Document Date	10/05/2016	Posting Date	09/30/2016	Period	9
Reference	NR	Cross-Comp.No.			
Currency	USD	Texts exist		Ledger Group	

Itm	PK	Account	Description	Order	Oper	Cost Center	Loc.curr.amount	Assignment
1	40	5040999	Oth Inc/Deds - Misc			10200	513,146.74	20160930
2	50	1010027	Gas Plant Adj				406,192.21-	20160930
3	50	1070028	Corp Adj-Gas CWIP				84,512.81-	20160930
4	50	1080115	Accum Dep-Accrl				22,441.72-	20160930
5	40	1080001	A/D-Rcls Depr CoRmvl				22,441.72	20160930
6	50	2540098	RegLia-ReclsRmvlCost				22,441.72-	20160930
7	50	5040999	Oth Inc/Deds - Misc			14769	485,083.94-	20160930
8	40	1010027	Gas Plant Adj				383,978.51	20160930
9	40	1070028	Corp Adj-Gas CWIP				79,891.00	20160930
10	40	1080115	Accum Dep-Accrl				21,214.43	20160930
11	50	1080001	A/D-Rcls Depr CoRmvl				21,214.43-	20160930
12	40	2540098	RegLia-ReclsRmvlCost				21,214.43	20160930

Purpose of the Journal Entry:
To record a high level write-off reserve for disallowed capital spend for the 2015-2016 portion associated with 2011-2014 overspend.

Account 1080115
(22,441.72) 2011-2014 Overspend Gas COR — HLA reversed via Oct 2020 JE 1002651102

(22,441.72) **Total Agrees to Summary**

Display Document: Data Entry View

Display Currency | General Ledger View

Data Entry View

Document Number	1001974135	Company Code	PGE1	Fiscal Year	2016
Document Date	11/03/2016	Posting Date	10/31/2016	Period	10
Reference	NR	Cross-Comp.No.			
Currency	USD	Texts exist		Ledger Group	

Itm	PK	Account	Description	Order	Oper	Cost Center	Loc.curr.amount	Assignment
1	40	5040999	Oth Inc/Deds - Misc			10200	22,522.89	20161031
2	50	1010027	Gas Plant Adj				129,477.42-	20161031
3	40	1070028	Corp Adj-Gas CWIP				84,512.81	20161031
4	40	1080115	Accum Dep-Accrl				22,441.72	20161031
5	50	1080001	A/D-Rcls Depr CoRmvl				22,441.72-	20161031
6	40	2540098	RegLia-ReclsRmvlCost				22,441.72	20161031

Purpose of the Journal Entry:
To record a high level write-off reserve for disallowed capital spend for the 2015-2016 portion associated with 2011-2014 overspend.

Account 1080115

22,441.72 2011-2014 Overspend Gas COR — HLA reversed via Oct 2020 JE 1002651102

22,441.72 Total Agrees to Summary

Display Document: Data Entry View

Display Currency | General Ledger View

Data Entry View

Document Number	1002651102	Company Code	PGE1	Fiscal Year	2020
Document Date	10/31/2020	Posting Date	10/31/2020	Period	10
Reference	NR	Cross-Comp.No.			
Currency	USD	Texts exist		Ledger Group	

Itm	PK	Account	Description	Order	Oper	Cost Center	Loc.curr.amount	Assignment
1	40	1010027	Gas Plant Adj				141,044,603.01	Plant
2	40	1080115	Accum Dep-Accrl				6,064,949.00	COR
3	40	1010027	Gas Plant Adj				1,034,655.00	Plant
4	50	5590049	Capital Disallowance	1014935			65,369,004.96-	Disallow Order
5	50	5590049	Capital Disallowance	1014935			1,034,655.00-	Disallow Order
6	50	5590049	Capital Disallowance	1014915			81,740,547.05-	Disallow Order
7	50	1080115	Accum Dep-Accrl				23,469,800.46-	Depr Reversal
8	40	5010010	Depr Exp - Gas			10926	23,469,800.46	Depr Reversal
9	50	2540098	RegLia-ReclsRmvlCost				3,077,253.77-	Reg Asset Reclass
10	40	1080001	A/D-Rcls Depr CoRmvl				3,077,253.77	Reg Asset Reclass
11	40	5010010	Depr Exp - Gas			10926	120,827.21	Oct20-9 Proj
12	50	1080115	Accum Dep-Accrl				120,827.21-	Oct20-9 Proj
13	40	1080001	A/D-Rcls Depr CoRmvl				42,367.98	Oct20-9 Proj
14	50	2540098	RegLia-ReclsRmvlCost				42,367.98-	Oct20-9 Proj
15	40	5010010	Depr Exp - Gas			10926	149,564.25	Oct20 - <$1M proj
16	50	1080115	Accum Dep-Accrl				149,564.25-	Oct20 - <$1M proj
17	40	1080001	A/D-Rcls Depr CoRmvl				51,840.37	Oct20 - <$1M proj
18	50	2540098	RegLia-ReclsRmvlCost				51,840.37-	Oct20 - <$1M proj

Account 1080115

6,064,949.00 2011-2014 Gas Reverse HL JE's (pushdown into subledger)

6,064,949.00 Total Agrees to Summary

Purpose of the Journal Entry:

To reverse prior SAP High Level entries related to 2011-2014 Overspend Capital Disallowance + $1M Audit Writeoff and associated Depreciation Reversals. The 2011-2014 Overspend Disallowance and Depreciation Reversals are being pushed down into PowerPlan in October 2020. See corresponding PowerPlan Journal Entry. The trigger for this entry is the receipt of the 2015 GT&S CapEx audit results.
Background: The 2015 GT&S rate case disallowed $160M of CapExp from 2011-2014.

Items 1-6: Plant and COR disallowances HLA reversal
Items 7-10: Depreciation Impact and Reg Liability Reclass HLA reversal
Items 11-18: Depreciation adjustment

Pacific Gas and Electric Company

Planning Order	Planning Order Description	Asset Class	Asset Class Description	MWC	MWC Description	Cost of Removal
[illegible]	[illegible]	[illegible]	[illegible]	[illegible]	[illegible]	[illegible]
5753058	L-162A REPL 0.85MI MP 6.62-7.40 PH1	GTP36700	Trans Plant: Mains	2H	GT PL Safety Enhance Plan-Cap	$ 0.01
5755503	DFM-1816-15 REPL 0.03MI MP 3.04-3.07 PH1	GTP36700	Trans Plant: Mains	2H	GT PL Safety Enhance Plan-Cap	$ (3,627.75)
5755511	L-021D REPL 0.62MI MP 18.65-19.27 PH1	GTP36700	Trans Plant: Mains	2H	GT PL Safety Enhance Plan-Cap	$ (1,194.58)
5755658	30959337-L-021C REPL 0.89MI MP50.44-51.4	GTP36700	Trans Plant: Mains	75	GT Pipeline Reliability	$ (328.59)
5757248	30952711 - L-109 MP 33.25 REPL TAP VLVE	GTP36700	Trans Plant: Mains	75	GT Pipeline Reliability	$ (320.80)
5757249	30955891 - L-300B MP 152.46 BRIDLE REPLC	GTP36700	Trans Plant: Mains	75	GT Pipeline Reliability	$ (77.20)
5757264	30982713 - 7228-01 MP 2.80 REMOVE AND RE	GTP36700	Trans Plant: Mains	75	GT Pipeline Reliability	$ (351.37)
5757298	31006657 - L-167 MP 17.41-29.24 REPL 1.5	GTP36700	Trans Plant: Mains	75	GT Pipeline Reliability	$ (977.04)
5757299	31007745 - ROSEVILLE RD STATION - L119D	GTP36700	Trans Plant: Mains	75	GT Pipeline Reliability	$ (190.77)
5757308	31015140 - DREG5072 LA SALLE ST TAP RETI	GTP36700	Trans Plant: Mains	75	GT Pipeline Reliability	$ (1,946.85)
5757310	31015147 - DFDS3596 V-235 & 0206-01 V-23	GTP36700	Trans Plant: Mains	75	GT Pipeline Reliability	$ (108.53)
5757323	31021267 - 2002-01 MP 2.9 VLV REPLACEMEN	GTP36700	Trans Plant: Mains	75	GT Pipeline Reliability	$ (39.65)
5757338	31034594 - L-301F MP 3.37 VALVE SET REPL	GTP36700	Trans Plant: Mains	75	GT Pipeline Reliability	$ (242.84)
5758257	31061065 - DFM 8807-01 MP 7.29 V-11-G8A	GTP36700	Trans Plant: Mains	75	GT Pipeline Reliability	$ (66.53)
5758931	30975922-L-303 LIVERMORE JNCT. STA. CUT-	GTP36700	Trans Plant: Mains	3K	Gas Trans Remediate Corrosion	$ (8,290.23)
5758958	0630-01_1.33_Replace	GTP36700	Trans Plant: Mains	75	GT Pipeline Reliability	$ (1,833.95)
5759052	30984355-L7224-19 MP1.4 OREGON/SANTA ANA	GTP36700	Trans Plant: Mains	76	GT Station Reliability	$ (2,519.43)
5759079	31077535-2403-02 RPLC 6-IN VALVE E47	GTP36700	Trans Plant: Mains	75	GT Pipeline Reliability	$ 31.73
5759098	31017173-REPLACE FIREVALVE V-98 - INLET	GTP36700	Trans Plant: Mains	75	GT Pipeline Reliability	$ (263.15)
5759118	31069525-DFM 0621-01 PACIFIC COAST REG S	GTP36700	Trans Plant: Mains	75	GT Pipeline Reliability	$ (4,370.35)
5759120	31070879-RT-090 DFM 1401-01 REPLACE DFM	GTP36700	Trans Plant: Mains	75	GT Pipeline Reliability	$ (46,378.54)
5759122	31073094-126A_6.34-6.35_GRADE 1LEAK REPL	GTP36700	Trans Plant: Mains	75	GT Pipeline Reliability	$ (2,990.84)
5759345	31086474-DFM 0617 ROSEVILLE ILI UPG LNCR	GTP36700	Trans Plant: Mains	98	GT Integrity Management	$ (3,703.96)
5759498	301F MP 5.0-5.2 DEL MONTE MARINA WRO	GTP36700	Trans Plant: Mains	83	GT WRO	$ 679.64
5759499	DFM 0206-01 Relocation ~ MP0.00 - MP0.09	GTP36700	Trans Plant: Mains	83	GT WRO	$ (291.55)
5759546	50A_2 MP 17.08-18.41	GTP36700	Trans Plant: Mains	75	GT Pipeline Reliability	$ (422,818.65)
5759558	3K5 Casings Remediation	GTP36700	Trans Plant: Mains	3K	Gas Trans Remediate Corrosion	$ (143,866.35)
5759593	187 MP 4.31 INOP MAINLINE VALVE SET	GTP36700	Trans Plant: Mains	75	GT Pipeline Reliability	$ (863.40)
5759597	InOp Valve - DFM 0601-01 MP 1.71 VV53	GTP36700	Trans Plant: Mains	75	GT Pipeline Reliability	$ (140.59)
5759599	InOp Valve - L159 MP 3.91 (PCreek) V-2	GTP36700	Trans Plant: Mains	75	GT Pipeline Reliability	$ (9.84)
5759606	L177a_MP43.87_Replace BOV A&B	GTP36700	Trans Plant: Mains	75	GT Pipeline Reliability	$ (774.56)
5759607	P-03 HOV @ Central & DeWolf	GTP36700	Trans Plant: Mains	75	GT Pipeline Reliability	$ (1,347.29)
5759612	L402_MP 32.80_Repl V0.01 DREG5485	GTP36700	Trans Plant: Mains	75	GT Pipeline Reliability	$ 15.97
5759620	L-300B MP 280.39-281.6 CCC	GTP36700	Trans Plant: Mains	75	GT Pipeline Reliability	$ (212,018.60)
5759626	195A3-1_0.00-0.03_Deactivate Pipeline	GTP36700	Trans Plant: Mains	84	GT Gas Gathering System Manage	$ (2,897.86)
5759763	12296 L-331B MP 0.76 1.31 REINFORCEMENT	GTP36700	Trans Plant: Mains	73	GT Pipeline Capacity	$ (4,383.67)
5759791	L-131 MP 46.34 - 50.57 RETIRE FREMONT	GTP36700	Trans Plant: Mains	75	GT Pipeline Reliability	$ (5,940,173.78)
5759792	L-107 M26.01-26.61 REPLACE 3150FT - 36IN	GTP36700	Trans Plant: Mains	75	GT Pipeline Reliability	$ (2,960.73)
5759793	L-107 MP29.27-31.21REPL FREMONT-IRVING	GTP36700	Trans Plant: Mains	75	GT Pipeline Reliability	$ (6,347.01)
5759794	L-300B , MP 344.5 CCC RPL 1800 FT OF 34	GTP36700	Trans Plant: Mains	75	GT Pipeline Reliability	$ (1,153.16)
5759796	L-132 MP41.83-42.95 REPLACE 3431-FT SSF0	GTP36700	Trans Plant: Mains	75	GT Pipeline Reliability	$ (1,557.16)
5759799	L-107 M31.22-33.20 RPLC 9200 FT BALIP	GTP36700	Trans Plant: Mains	75	GT Pipeline Reliability	$ (414,408.27)
5759801	L21A FAULT CROSSING MITIGATION	GTP36700	Trans Plant: Mains	75	GT Pipeline Reliability	$ (282.38)
5759804	191-1 MP XX LOWERING MAIN (CAPITAL)	GTP36700	Trans Plant: Mains	75	GT Pipeline Reliability	$ (554.43)
5759810	L-400/401 MP 246 CACHE CREEK RELO	GTP36700	Trans Plant: Mains	75	GT Pipeline Reliability	$ (1,244.67)
5759838	DFM-7222-01 REPL 0.62MI MP 0.00-0.61	GTP36700	Trans Plant: Mains	83	GT WRO	$ (2,475.47)
5759839	`-368 L-119D MP1.06-1.28 REPL 6 " PIPE W	GTP36700	Trans Plant: Mains	83	GT WRO	$ (14,315.36)
5759841	L-131 MP-32.00 RPLC 2400 FT OF 24-IN WRO	GTP36700	Trans Plant: Mains	83	GT WRO	$ (11,731.97)
5759842	RT-80 DFM 1305-01_MP 6.89_WRO PIPELINE R	GTP36700	Trans Plant: Mains	83	GT WRO	$ (1,202.27)
5759843	DFM0619-01 MP0.87-1.02 WEST SAC CONFLICT	GTP36700	Trans Plant: Mains	83	GT WRO	$ (9,297.65)
5759846	132B MP 0.30-0.37 RELOCTE 400 FT	GTP36700	Trans Plant: Mains	83	GT WRO	$ (4,917.36)
5759861	L-119C ILI Upgrade MP 0.00-6.669	GTP36700	Trans Plant: Mains	98	GT Integrity Management	$ (80,294.22)
5760843	31083050-L-111C MP 0.1 GRADE 2+ LEAK REP	GTP36700	Trans Plant: Mains	75	GT Pipeline Reliability	$ (764.71)
5760938	31085620-DFM 0214-01 MP 1.03 REPLACE V-4	GTP36700	Trans Plant: Mains	75	GT Pipeline Reliability	$ (862.77)
5760942	31097407-INOP VALVE - L220 MP 34.11 V-1	GTP36700	Trans Plant: Mains	75	GT Pipeline Reliability	$ (1,178.10)
5761258	R-322, L-181B MP1.2 San Andreas Fault	GTP36700	Trans Plant: Mains	75	GT Pipeline Reliability	$ (255.61)
5761338	31095740-L-302-175 TEST MP 0 TO 0.05 CAP	GTP36700	Trans Plant: Mains	75	GT Pipeline Reliability	$ 756.71
5761942	31111882-INOP VALVE - L220 MP 12.18 V-1	GTP36700	Trans Plant: Mains	75	GT Pipeline Reliability	$ 7.69
5762018	DFM 1815-02 TEST MP12.74 - 14.75 CAPITAL	GTP36700	Trans Plant: Mains	75	GT Pipeline Reliability	$ (3,445.59)
5762181	L50A MP 31.64 Leak Repair	GTP36700	Trans Plant: Mains	75	GT Pipeline Reliability	$ (183.94)
5762463	R353 L105N m13.36 Rel 2400 ft of 24" WRO	GTP36700	Trans Plant: Mains	83	GT WRO	$ (35.27)
5762496	31086128-L-215 MLV 8.40- MLV 17.10 ILI U	GTP36700	Trans Plant: Mains	98	GT Integrity Management	$ (420,798.21)
5762498	31086130-L215 MLV12.99-WESTAVE REGSTA IL	GTP36700	Trans Plant: Mains	98	GT Integrity Management	$ 51,557.69
5762499	31086131-L-215 OAK FLAT MTR STA- MLV6 IL	GTP36700	Trans Plant: Mains	98	GT Integrity Management	$ (1,215.77)
5762500	31037502-L-138 ILI UPGRADE MP 43.58-49.4	GTP36700	Trans Plant: Mains	98	GT Integrity Management	$ 1,159.90
5762509	31086124-L-138C MP 43.58-50.02 ILI UPGRA	GTP36700	Trans Plant: Mains	98	GT Integrity Management	$ (1,893.27)
5762513	31037504-DFM 1202-16 MP 2.59-4.60 ILI UP	GTP36700	Trans Plant: Mains	98	GT Integrity Management	$ (558.82)
5762558	L197C MP 8.47 Replace V-A[_]V-B InOp Val	GTP36700	Trans Plant: Mains	75	GT Pipeline Reliability	$ (181.83)
5762862	7204-01 Gertrude Ave. & Winton Way. V-1	GTP36700	Trans Plant: Mains	75	GT Pipeline Reliability	$ (1,567.06)
5763391	1812-13_MP0.0000-2.1000	GTP36700	Trans Plant: Mains	3K	Gas Trans Remediate Corrosion	$ (603,706.90)
5763426	CD-09A - L-105N MP 33.28 CASING REMOVAL	GTP36700	Trans Plant: Mains	3K	Gas Trans Remediate Corrosion	$ (185.79)
5763432	GT CASING REMEDIATION 050A MP 27.01	GTP36700	Trans Plant: Mains	3K	Gas Trans Remediate Corrosion	$ (6,443.56)
5763460	L-300A. 3 LOCATIONS ANODE/RECT REPLACE	GTP36700	Trans Plant: Mains	3K	Gas Trans Remediate Corrosion	$ 8.75
5763479	LINE 0821-02 MP 0.43	GTP36700	Trans Plant: Mains	3K	Gas Trans Remediate Corrosion	$ 292.67
5763498	LINE 108 MP 47.06	GTP36700	Trans Plant: Mains	3K	Gas Trans Remediate Corrosion	$ (1,872.40)
5763528	LINE 153MP 2.26	GTP36700	Trans Plant: Mains	3K	Gas Trans Remediate Corrosion	$ (10,524.05)
5763555	RT-092 L177A_MP 94.56_CASING REMEDIATION	GTP36700	Trans Plant: Mains	3K	Gas Trans Remediate Corrosion	$ (96.51)
5763585	L111A MP 18.5 RMDA 200 RECOAT	GTP36700	Trans Plant: Mains	3K	Gas Trans Remediate Corrosion	$ (3,931.02)
5763723	L-169A_MP 5.07_Repl BOV D @ Valve 230	GTP36700	Trans Plant: Mains	75	GT Pipeline Reliability	$ 496.27
5763746	RT-115L-21EMP73.59ILI Dig#4ReplacePipe	GTP36700	Trans Plant: Mains	75	GT Pipeline Reliability	$ (12.15)
5763776	L-21E-2 MP 0.06 4inch DISTRIBUTION HDD	GTP36700	Trans Plant: Mains	75	GT Pipeline Reliability	$ (193.96)
5763785	L-114 REPL 0.38MI MP 16.86-17.06	GTP36700	Trans Plant: Mains	75	GT Pipeline Reliability	$ (0.82)
5763788	L-314 MP 24.92 EMERGANCY LEAK REPAIR-	GTP36700	Trans Plant: Mains	75	GT Pipeline Reliability	$ (7.53)
5763789	L-021B MP 3.88 FAULT CROSSING MITIGATION	GTP36700	Trans Plant: Mains	75	GT Pipeline Reliability	$ (265.11)
5763790	RT-124 132 MP 3.07 EMERGENCY CASING LEAK	GTP36700	Trans Plant: Mains	75	GT Pipeline Reliability	$ (816.80)
5763802	L-121 MP 0.00-6.99 T-1002 CAPITAL	GTP36700	Trans Plant: Mains	75	GT Pipeline Reliability	$ (73,369.93)
5763859	3022-01 MP-1.01 REPLACE 8-IN PCF	GTP36700	Trans Plant: Mains	75	GT Pipeline Reliability	$ (303.35)
5764276	L-401 MP 2465.00 Cache Creek Relocation	GTP36700	Trans Plant: Mains	75	GT Pipeline Reliability	$ 85.16
5764346	1813-02 MP 10.61 MLV Set Replacement	GTP36700	Trans Plant: Mains	75	GT Pipeline Reliability	$ (26,641.77)
5764626	LINE 0821-01 MP 1.66 CASING REMEDIATION	GTP36700	Trans Plant: Mains	3K	Gas Trans Remediate Corrosion	$ 400.01
5764711	GCUST5813 MP 1.08 REMOVE V-50-H4AB	GTP36700	Trans Plant: Mains	75	GT Pipeline Reliability	$ (340,063.24)
5764880	L-191-1 GRADE 2+ 10" V-3 REMOVAL	GTP36700	Trans Plant: Mains	75	GT Pipeline Reliability	$ (22,755.20)
5764898	GCUST5755 Deactivate Cogen line	GTP36700	Trans Plant: Mains	26	GT Customer Connects	$ 26,886.28
5764948	L150_MP 16.56_17.48_Retirement	GTP36700	Trans Plant: Mains	75	GT Pipeline Reliability	$ (267,636.63)
5765100	DFM 1816-02 MP 0.00-0.06 T-246	GTP36700	Trans Plant: Mains	75	GT Pipeline Reliability	$ (2,137.63)
5765351	105C MP 0.01 BART CONFLICT RETIRE D-70	GTP36700	Trans Plant: Mains	83	GT WRO	$ (1,859.33)
5765398	30984579	GTP36700	Trans Plant: Mains	75	GT Pipeline Reliability	$ (169,434.09)
5765830	L-132 Replace 100ft 24 MP 49.57	GTP36700	Trans Plant: Mains	83	GT WRO	$ (28,627.43)
5766166	R-008B L-108 MP 39.01-40.27	GTP36700	Trans Plant: Mains	75	GT Pipeline Reliability	$ 2,968.52
5766223	L-119C ILI UPGRADE MP 3.54 & 3.65	GTP36700	Trans Plant: Mains	98	GT Integrity Management	$ (19,334.74)
5766399	DFM 0401-01 TEST MP 4.89- 4.925 CAPITAL	GTP36700	Trans Plant: Mains	75	GT Pipeline Reliability	$ (200,316.64)
5766400	DFM 1816-01 TEST MP 12.78-16.30 CAPITAL	GTP36700	Trans Plant: Mains	75	GT Pipeline Reliability	$ (660,941.63)
5766401	L-118A MP 28.59-36.03 T-1031 CAPITAL	GTP36700	Trans Plant: Mains	75	GT Pipeline Reliability	$ (6,153.68)
5766402	L-118A MP 54.75-58.215 T-1033 CAPITAL	GTP36700	Trans Plant: Mains	75	GT Pipeline Reliability	$ (10,581.58)
5766404	GT DFM-1601-09 MP 0.00-0.86 T-1058 CAPIT	GTP36700	Trans Plant: Mains	75	GT Pipeline Reliability	$ (1,159.90)
5766406	L-118A MP 17.74-17.75 T-1028 CAPITAL	GTP36700	Trans Plant: Mains	75	GT Pipeline Reliability	$ (16,305.68)
5766408	L-118A MP 72.514 T-1037 CAPITAL	GTP36700	Trans Plant: Mains	75	GT Pipeline Reliability	$ (17,752.07)
5766410	L-118A MP 78.01-83.43 T-1038 CAPITAL	GTP36700	Trans Plant: Mains	75	GT Pipeline Reliability	$ (11,027.13)
5766411	DFM 0402-01 MP 4.9-5.055 T-1008 CAPITAL	GTP36700	Trans Plant: Mains	75	GT Pipeline Reliability	$ (327,629.69)
5766413	DFM 7222-01 MP 0.00-0.60 T-1079 CAPITAL	GTP36700	Trans Plant: Mains	75	GT Pipeline Reliability	$ (4,596.78)
5766415	L-118A MP 37.725-43.64 T-1032 CAPITAL	GTP36700	Trans Plant: Mains	75	GT Pipeline Reliability	$ (33,610.63)
5766416	DFM-1615-07 MP 0.00-0.25 T-1059 CAPITAL	GTP36700	Trans Plant: Mains	75	GT Pipeline Reliability	$ 1,830.54
5766442	L-1818-01 MP 4.66 Rectifier Replacement	GTP36700	Trans Plant: Mains	3K	Gas Trans Remediate Corrosion	$ (1,399.35)
5766455	137D_3.11_Grade 2+ Leak	GTP36700	Trans Plant: Mains	75	GT Pipeline Reliability	$ (1,001.05)
5766486	RT-118 L-105A MP 38.0-38.44 REPL	GTP36700	Trans Plant: Mains	75	GT Pipeline Reliability	$ (36,253.54)
5766489	RT-121 STUB7941-STUB7942 REPL	GTP36700	Trans Plant: Mains	75	GT Pipeline Reliability	$ (898.45)
5766490	RT-129 L-105N-5 MP 36.39 REPL	GTP36700	Trans Plant: Mains	75	GT Pipeline Reliability	$ (13,442.35)
5766491	RT-629 L-162A MP 6.05-6.08 REPL	GTP36700	Trans Plant: Mains	75	GT Pipeline Reliability	$ (89,799.34)
5767635	R-531 L-021C SPAN REMOVAL MP 32.21-32.23	GTP36700	Trans Plant: Mains	2H	GT PL Safety Enhance Plan-Cap	$ (3,651.25)
5768103	DFM 0607-01 MP 2.85 Rplc InOp V-A47	GTP36700	Trans Plant: Mains	75	GT Pipeline Reliability	$ (13,300.45)
5768267	Fault Crossings Program Bucket	GTP36700	Trans Plant: Mains	75	GT Pipeline Reliability	$ (38.73)
5769459	021F_1.47_Replace InOp V-1	GTP36700	Trans Plant: Mains	75	GT Pipeline Reliability	$ (12,099.77)
5769800	RT-738 L-121 MP 10.53 CAPITAL	GTP36700	Trans Plant: Mains	75	GT Pipeline Reliability	$ (89,727.11)
5770108	187 MP 41.67 V-1 INOP VALVE REPLACEMENT	GTP36700	Trans Plant: Mains	75	GT Pipeline Reliability	$ (9,998.50)
5770321	L-153 MP 25.96 -26.48	GTP36700	Trans Plant: Mains	75	GT Pipeline Reliability	$ (694,056.29)
5770562	I-103E L-173 MP 7.63 REPL MLV-7.63	GTP36700	Trans Plant: Mains	98	GT Integrity Management	$ (36,424.02)
5770563	I-041G L-108 MP 71.91-74.93 ILI UPGRADE	GTP36700	Trans Plant: Mains	98	GT Integrity Management	$ (284,015.87)
5770568	L-109 ILI SWITCHING STATION MP 23.30	GTP36700	Trans Plant: Mains	98	GT Integrity Management	$ (5,006.12)
5770584	I-043B L-109 REMOVE 1D ELBOW MP 0.68	GTP36700	Trans Plant: Mains	98	GT Integrity Management	$ (612.72)
5770599	R-570 L-147 MP 2.35 ILI CUT OUT (RT)	GTP36700	Trans Plant: Mains	98	GT Integrity Management	$ 153,045.57
5771099	1217-01 MP 1.87-2.91 T-1125 CAPITAL	GTP36700	Trans Plant: Mains	75	GT Pipeline Reliability	$ (21,537.29)
5772118	L-215 MP 0.278-4.89 T-1196 CAPITAL	GTP36700	Trans Plant: Mains	75	GT Pipeline Reliability	$ (277,751.73)
5772938	30604187-L-132, Mp 0.93-1.87 Replace	GTP36700	Trans Plant: Mains	75	GT Pipeline Reliability	$ (8.13)
5783828	DFM1615-01 MP 16.59-18.35 T-1017 CAPITAL	GTP36700	Trans Plant: Mains	75	GT Pipeline Reliability	$ (22,081.41)
5783944	'RT-146 L-314 MP 24.75-24.92 REPLACE 10"	GTP36700	Trans Plant: Mains	75	GT Pipeline Reliability	$ (2,268.82)
5746858	DFM-2410-01 REPL 0.01MI MP 0.00-0.01 PH1	GTP36703	Trans Plant: Mains (PSEP)	2H	GT PL Safety Enhance Plan-Cap	$ 8.98
Overall Result						**$ (9,189,962.18)**

Journal Entries:

	GAS - COST OF REMOVAL ADJ	$ 36,091.38
Total		$ (9,153,870.80)

6780439	2615-01 MP 6.16 Replace D-37 InOp Valve	GTP26700	Trans Plant: Maint	75	GT Pipeline Reliability	$ (52.25)
6785883	2618-10_1.44_V398 Replace	GTP26700	Trans Plant: Maint	75	GT Pipeline Reliability	$ (6,147.71)
6787118	2804-10 GCUST8310 Retirement	GTP26700	Trans Plant: Maint	83	GT WRO	$ (217,595.62)
6786370	2813-08 MP 1.4976 Replace InOp V-76-C3A	GTP26700	Trans Plant: Maint	75	GT Pipeline Reliability	$ (53,981.09)
6789179	2813-08 MP 4.01 REPLACE 3 INOP VALVES	GTP26700	Trans Plant: Maint	75	GT Pipeline Reliability	$ (28,597.39)
6530941	2813-13 MP 2.66 CASING Removal	GTP26700	Trans Plant: Maint	3K	Gas Trans Remediate Corrosion	$ 39,689.08
6772822	2814-04 MP 0.00-0.37 6" CPSI Retirement	GTP26700	Trans Plant: Maint	75	GT Pipeline Reliability	$ 392.15
6535014	2821-02 MP 2.33 Pipe Replacement	GTP26700	Trans Plant: Maint	3K	Gas Trans Remediate Corrosion	$ 6.69
6771028	2821-02 MP 7.55-8.16 BASCOM VALVE ISSUES	GTP26700	Trans Plant: Maint	75	GT Pipeline Reliability	$ 123.35
6777638	2824-02 MP 1.63-1.81 MAOP VALVE REM	GTP26700	Trans Plant: Maint	75	GT Pipeline Reliability	$ (15,238.44)
6784120	2840-01 0.10 Replace 2" INOP V-13-04A	GTP26700	Trans Plant: Maint	75	GT Pipeline Reliability	$ (337.71)
6773402	101 MP 27.08-28.84 (26.88-29.07) S Mateo	GTP26700	Trans Plant: Maint	75	GT Pipeline Reliability	$ 968.44
6773403	101, MP 33.06-33.68 Lomita Park, Millbrae	GTP26700	Trans Plant: Maint	75	GT Pipeline Reliability	$ (37.84)
6779761	1027-09_V-022_Replace Inoperable Valve	GTP26700	Trans Plant: Maint	75	GT Pipeline Reliability	$ 347.63
6772275	103_22.94167_23.23886_REPLACE_IMFLAG	GTP26700	Trans Plant: Maint	75	GT Pipeline Reliability	$ 2,584.25
6778081	105B_Valves Rplc w/in Crockett Station	GTP26700	Trans Plant: Maint	75	GT Pipeline Reliability	$ (1,741.49)
6781588	105C & 105N extension to Oakland Station	GTP26700	Trans Plant: Maint	75	GT Pipeline Reliability	$ (1,414.66)
6781882	105N_31.8_Replace 100 feet 20"	GTP26700	Trans Plant: Maint	75	GT Pipeline Reliability	$ (682.31)
6782072	105N-2_0.00-1.29_Retire pipeline	GTP26700	Trans Plant: Maint	75	GT Pipeline Reliability	$ 192,338.38
6758631	105N, MP 28.13-30.27	GTP26700	Trans Plant: Maint	75	GT Pipeline Reliability	$ (29.17)
6784643	109_27.93_replace V-27.93 & V-280	GTP26700	Trans Plant: Maint	75	GT Pipeline Reliability	$ (28,157.38)
6779758	111A_Rplc V-21.70 GR 2 Leak	GTP26700	Trans Plant: Maint	75	GT Pipeline Reliability	$ (150.15)
6784463	111A-1 MP8.11 REPLACE MLV	GTP26700	Trans Plant: Maint	75	GT Pipeline Reliability	$ 67.22
6776881	111A-1_3.88_Relocation_WRO	GTP26700	Trans Plant: Maint	83	GT WRO	$ (15,297.82)
6782342	119A_2.36_Replace Inop V-1	GTP26700	Trans Plant: Maint	75	GT Pipeline Reliability	$ 11.34
6783458	1202-01 MP2.13 Valve B-01 Removal	GTP26700	Trans Plant: Maint	75	GT Pipeline Reliability	$ (5,919.32)
6765082	1202-16 ILI UPGRADE MP 0-2.59	GTP26700	Trans Plant: Maint	98	GT Integrity Management	$ (133.65)
6768708	1248_Retirement	GTP26700	Trans Plant: Maint	75	GT Pipeline Reliability	$ 28,059.12
6527881	1301-01 MP 3.17 Rectifier and DWA	GTP26700	Trans Plant: Maint	3K	Gas Trans Remediate Corrosion	$ (3,212.11)
6783543	1302-01_1.76_Replacement	GTP26700	Trans Plant: Maint	73	GT Pipeline Capacity	$ (70,558.05)
6533939	1305-01 MP0 GRADE 2 LEAK	GTP26700	Trans Plant: Maint	75	GT Pipeline Reliability	$ (10.50)
6777679	1307-01 MP9.206 Leak Repair & Tee Rmvl	GTP26700	Trans Plant: Maint	75	GT Pipeline Reliability	$ (19.97)
6782515	1307-01_1.64-6.17_Retire	GTP26700	Trans Plant: Maint	75	GT Pipeline Reliability	$ (1,009,587.83)
6532684	1307-02 0.08 Cutout Leaking Valve V-9	GTP26700	Trans Plant: Maint	75	GT Pipeline Reliability	$ 40,264.98
6541693	1313-01 0.45 Elk River Rd. Station Leak	GTP26700	Trans Plant: Maint	75	GT Pipeline Reliability	$ (29,191.77)
6777840	132_18.16_Replace_V-245_	GTP26700	Trans Plant: Maint	75	GT Pipeline Reliability	$ (4.36)
6783367	142S MP11.1 Replace Casing	GTP26700	Trans Plant: Maint	3K	Gas Trans Remediate Corrosion	$ (109,202.54)
6535062	143 Remove Retired 4" pipe	GTP26700	Trans Plant: Maint	83	GT WRO	$ (52,826.49)
6781599	1502-01_1502-01_1.51-2.15_Caltrans WRO	GTP26700	Trans Plant: Maint	83	GT WRO	$ (14,288.54)
6536022	1514-01 MP 2.0 Retirement	GTP26700	Trans Plant: Maint	75	GT Pipeline Reliability	$ (62,423.65)
6774946	153_Replace Leaking Valves X-58 & E-78	GTP26700	Trans Plant: Maint	75	GT Pipeline Reliability	$ 0.02
6758630	153, MP 23.77-26.05	GTP26700	Trans Plant: Maint	75	GT Pipeline Reliability	$ (6,875.01)
6758635	153, MP 26.62-27.76	GTP26700	Trans Plant: Maint	75	GT Pipeline Reliability	$ 990.44
6783417	159 MP 0.65 Remove V-0.65	GTP26700	Trans Plant: Maint	75	GT Pipeline Reliability	$ (32.66)
6772586	1601-09_MP0.53-0.86_Retire_6inch	GTP26700	Trans Plant: Maint	75	GT Pipeline Reliability	$ (109,397.99)
6783315	1611-03_MP0.845-0.861_Pipe_Repl	GTP26700	Trans Plant: Maint	3K	Gas Trans Remediate Corrosion	$ 4,196.12
6784375	1614-08 MP0.7033-0.760 WRO replacement	GTP26700	Trans Plant: Maint	83	GT WRO	$ (178,359.87)
6776744	1614-13_MP1.06_Rplc Inaccessible_V-572	GTP26700	Trans Plant: Maint	75	GT Pipeline Reliability	$ (7.46)
6774673	167-30_MP 0.00-2.32_Retire_Maui	GTP26700	Trans Plant: Maint	64	GT Gas Gathering System Manage	$ 142.48
6784023	177A 9.07 - 9.10 Replace 165-ft of 10-in	GTP26700	Trans Plant: Maint	75	GT Pipeline Reliability	$ (1,622.39)
6530339	177A MP 94.33 Groundbed Replacement	GTP26700	Trans Plant: Maint	3K	Gas Trans Remediate Corrosion	$ (13.14)
6775458	177A_26.40_26.53_IMFLAG_Replace Drip	GTP26700	Trans Plant: Maint	75	GT Pipeline Reliability	$ (4,775.01)
6783459	177A-3 Mp 28.34 to 29.87 Deactivation	GTP26700	Trans Plant: Maint	75	GT Pipeline Reliability	$ (16,439.47)
6772298	1805-01 CALTRANS WRO SALINAS RVR BRDG	GTP26700	Trans Plant: Maint	83	GT WRO	$ 2,582.46
6784642	1815-02 MP 14.65 MLV Set Replacement AMC	GTP26700	Trans Plant: Maint	75	GT Pipeline Reliability	$ (26,876.74)
6789479	1816-01 MP 1.06 A14-1 Inop Valve	GTP26700	Trans Plant: Maint	75	GT Pipeline Reliability	$ (107,346.62)
6765208	1816-01 MP 1.19 & 181A MP 20.01 RPLMT	GTP26700	Trans Plant: Maint	75	GT Pipeline Reliability	$ (0.06)
6774067	1816-01 MP 6.13 INOP TAP V-B08-1	GTP26700	Trans Plant: Maint	75	GT Pipeline Reliability	$ (64,235.70)
6769123	1816-50 MP 0.00-1.12 REPL	GTP26700	Trans Plant: Maint	75	GT Pipeline Reliability	$ (18.05)
6772758	1817-01 MP 1.25-2.0	GTP26700	Trans Plant: Maint	75	GT Pipeline Reliability	$ (133.12)
6781681	1817-03 MP 1.05 MLV Install Compliance S	GTP26700	Trans Plant: Maint	75	GT Pipeline Reliability	$ (13.36)
6773400	1818-01 MP 0.12-0.36 -615 7th Ave S Cruz	GTP26700	Trans Plant: Maint	75	GT Pipeline Reliability	$ (331.84)
6782560	1818-01 MP 6.4 Geohazard Emergency SC	GTP26700	Trans Plant: Maint	75	GT Pipeline Reliability	$ (1,423.18)
6770620	187 MP22.58 INOP VLV REMOVAL V-2 V-A V-B	GTP26700	Trans Plant: Maint	75	GT Pipeline Reliability	$ 0.01
6766502	191-1 MP XX LOWERING MAIN (CAPITAL)	GTP26700	Trans Plant: Maint	75	GT Pipeline Reliability	$ (1,176.73)
6781962	191-1_25.5_Replace Exposed Pipe	GTP26700	Trans Plant: Maint	75	GT Pipeline Reliability	$ (35.30)
6529123	191A MP 2.1 Replacement DWA & Rect	GTP26700	Trans Plant: Maint	3K	Gas Trans Remediate Corrosion	$ (23.50)
6758699	193-018_MP0-0.2416_Retire_Pipeline	GTP26700	Trans Plant: Maint	64	GT Gas Gathering System Manage	$ 0.55
6772821	197A_MP21.41_Remove Inop_V-C	GTP26700	Trans Plant: Maint	75	GT Pipeline Reliability	$ (234.34)
6758600	197A_MP5.19_Replace_V-2	GTP26700	Trans Plant: Maint	75	GT Pipeline Reliability	$ (34.14)
6777219	199_0.0-0.93_Retire Bunker RP	GTP26700	Trans Plant: Maint	64	GT Gas Gathering System Manage	$ (1,769,173.94)
6777122	200-188_0.00_Retire Hanson RP	GTP26700	Trans Plant: Maint	64	GT Gas Gathering System Manage	$ (46,586.57)
6764739	200C10-1,200C7-3 MP 0.06-0.9 RETIRE 2.5M	GTP26700	Trans Plant: Maint	64	GT Gas Gathering System Manage	$ (38.33)
6765540	2017 L-300A ILI UPGRADE MP 40.89-103.72	GTP26700	Trans Plant: Maint	98	GT Integrity Management	$ 176.20
6765542	2017 L-300B ILI UPGRADE MP 40.49-103.5	GTP26700	Trans Plant: Maint	98	GT Integrity Management	$ (161.56)
6773288	210A, MP 21.88-24.08 (American Canyon)	GTP26700	Trans Plant: Maint	75	GT Pipeline Reliability	$ (69,300.16)
6781253	215_MP 14.56_Valve Replacement	GTP26700	Trans Plant: Maint	75	GT Pipeline Reliability	$ (1,444.05)
6780039	21E_125.40_Grd 2 Leak Valve Replacement	GTP26700	Trans Plant: Maint	75	GT Pipeline Reliability	$ (33.77)
6778648	21F MP 0.00 Grade 1 Lk	GTP26700	Trans Plant: Maint	75	GT Pipeline Reliability	$ (456.10)
6777996	21F_11.31-11.56_Replace	GTP26700	Trans Plant: Maint	75	GT Pipeline Reliability	$ (26,266.95)
6541028	21G MP 2.61 Rmv Valve Lot Gr 1 LK	GTP26700	Trans Plant: Maint	75	GT Pipeline Reliability	$ (567,250.24)
6529720	2402-01_MP 2.36-3.04 Hayward Fault	GTP26700	Trans Plant: Maint	75	GT Pipeline Reliability	$ (9.05)
6783542	2403-01 MP0.06 Grade 2 Leak X-73	GTP26700	Trans Plant: Maint	75	GT Pipeline Reliability	$ (2,178.48)
6784374	2408-11 0.95 Replace Valve D-85 Gr2 Leak	GTP26700	Trans Plant: Maint	75	GT Pipeline Reliability	$ (1,230.88)
6776552	2408-17_0.22_Remove valve D-27	GTP26700	Trans Plant: Maint	75	GT Pipeline Reliability	$ (0.70)
6758754	3001-01 , MP 2.02-3.11 CAPACITY	GTP26700	Trans Plant: Maint	73	GT Pipeline Capacity	$ (945.06)
6780888	3006-01_2.24_C-80 Inop Valve Rplc	GTP26700	Trans Plant: Maint	75	GT Pipeline Reliability	$ (107.06)
6768699	3009-01 retirement of transmission asset	GTP26700	Trans Plant: Maint	76	GT Station Reliability	$ (47,080.18)
6773990	300A MP 280.58-353.57 Test CAPITAL	GTP26700	Trans Plant: Maint	75	GT Pipeline Reliability	$ (66.63)
6770622	300A_280.58-281.13_CCC Replace	GTP26700	Trans Plant: Maint	75	GT Pipeline Reliability	$ (16.34)
6776158	300A_MP260.02_MP270.74_Stub Removal	GTP26700	Trans Plant: Maint	75	GT Pipeline Reliability	$ 4,089.08
6773991	300B MP 299.01-353.50 Test CAPITAL	GTP26700	Trans Plant: Maint	75	GT Pipeline Reliability	$ (289.56)
6777276	300B MP 415.09 BD602 HCA RELOCATION	GTP26700	Trans Plant: Maint	75	GT Pipeline Reliability	$ (193.89)
6774840	300B MP 488.13-488.14 CLASS LOCATION	GTP26700	Trans Plant: Maint	75	GT Pipeline Reliability	$ (4.93)
6780361	300B MP464.46 CALAVERAS FAULT VALVE AUTO	GTP26700	Trans Plant: Maint	75	GT Pipeline Reliability	$ (167.02)
6772545	301 & 181A Valve Lot	GTP26700	Trans Plant: Maint	75	GT Pipeline Reliability	$ 489.59
6773665	3012-01 MP 0.027-0.172 REPLACE	GTP26700	Trans Plant: Maint	75	GT Pipeline Reliability	$ (48.05)
6530040	3014-01 MP 1.35 Rectifier Replace	GTP26700	Trans Plant: Maint	3K	Gas Trans Remediate Corrosion	$ (1,657.78)
6779578	301A MP 1.87 RUSTIC SALLY V-1 REPLACE	GTP26700	Trans Plant: Maint	75	GT Pipeline Reliability	$ (4.84)
6765801	301A MP 2.06-2.09 ILI REPLACEMENT	GTP26700	Trans Plant: Maint	75	GT Pipeline Reliability	$ 743.83
6778259	301G 105.3 MP 2.34-2.75 Calaveras Fault	GTP26700	Trans Plant: Maint	75	GT Pipeline Reliability	$ 5,957.56
6780943	301G MP 1.87 RUSTIC SALLY V-4 REPLACE	GTP26700	Trans Plant: Maint	75	GT Pipeline Reliability	$ (254.86)
6779037	301G V-11.31 ANZAR TAP MLV REPLACEMENT	GTP26700	Trans Plant: Maint	75	GT Pipeline Reliability	$ (32.18)
6777121	302-077_0.00-0.46_Retire Balsdon 10 RP	GTP26700	Trans Plant: Maint	64	GT Gas Gathering System Manage	$ (2,594.66)
6777123	302-096 Retire 4500ft Doheny-Tuttle	GTP26700	Trans Plant: Maint	64	GT Gas Gathering System Manage	$ (2,157.34)
6777218	302-162 Retire 1700ft Voodoo Child 1	GTP26700	Trans Plant: Maint	64	GT Gas Gathering System Manage	$ (5,144.29)
6542359	303 MP 3.7 Replace Rectifier	GTP26700	Trans Plant: Maint	83	GT WRO	$ (1,782.54)
6775521	304_MP0.0-3.11_12inch_Retirement	GTP26700	Trans Plant: Maint	83	GT WRO	$ (103,624.00)
6734538	30603913-L-210b Mp 1.37-25.98 Ili Upgrad	GTP26700	Trans Plant: Maint	98	GT Integrity Management	$ 14,595.54
6723872	30603914-L-210c Mp 19.46-32.11 Ili Upgra	GTP26700	Trans Plant: Maint	98	GT Integrity Management	$ 464,787.21
6723873	30603915-L-300a Mp256.21-299.01 Ili Upgr	GTP26700	Trans Plant: Maint	98	GT Integrity Management	$ 32,124.89
6723874	30603916-L-300b Mp256.64-299.00 Ili Upgr	GTP26700	Trans Plant: Maint	98	GT Integrity Management	$ 25,353.48
6723880	30603919-L-210a Ili Mp1.38-19.47 Pipeln	GTP26700	Trans Plant: Maint	98	GT Integrity Management	$ 42,632.88
6726804	30604188-L-132 Mp 42.95-43.63 Replace -	GTP26700	Trans Plant: Maint	75	GT Pipeline Reliability	$ 105,435.19
6729479	30604309-L-108, Mp 11.73-14.13, 24 Re	GTP26700	Trans Plant: Maint	73	GT Pipeline Capacity	$ 9,179.18
6729480	30604310-L-108 Repl 3.09mi Mp 40.27-43.5	GTP26700	Trans Plant: Maint	75	GT Pipeline Reliability	$ 44,418.72
6751300	30605982 - 0646-01 MP 8.9-4.8 CACHE CRK	GTP26700	Trans Plant: Maint	75	GT Pipeline Reliability	$ 12,179.92
6733652	30628215-L131 M27.02-28.00 REPLACE 5100	GTP26700	Trans Plant: Maint	75	GT Pipeline Reliability	$ (612.15)
6733833	30677653-L-108 IM MP 61.66- 63.50 INST B	GTP26700	Trans Plant: Maint	75	GT Pipeline Reliability	$ 11,601.62
6733834	30677708-L-107m13.08-15.70retire13835'-2	GTP26700	Trans Plant: Maint	75	GT Pipeline Reliability	$ 438,736.16
6741896	30704063-L187 Mp 62 - 8Pipe Replaceme	GTP26700	Trans Plant: Maint	75	GT Pipeline Reliability	$ 2,252.02
6738975	30711380-L-304 0.0-14.0 RETIRE & CONVERT	GTP26700	Trans Plant: Maint	75	GT Pipeline Reliability	$ 0.02
6747987	30712993-L-101 Mp 11.83-33.68 Ili Upgrad	GTP26700	Trans Plant: Maint	98	GT Integrity Management	$ 984,000.66
6748018	30712995-L-101 Mp 0.00-11.85 Ili Upgrade	GTP26700	Trans Plant: Maint	98	GT Integrity Management	$ 324,322.48
6735705	30716298-L-107mp16.68-22.3dretire9115'-	GTP26700	Trans Plant: Maint	75	GT Pipeline Reliability	$ 325,885.30
6735706	30716299-L-107m22.34-26.01retire 11195'	GTP26700	Trans Plant: Maint	75	GT Pipeline Reliability	$ 189,812.22
6751339	30723268 - DFM 0405-01, MP 12.09 REMOVE	GTP26700	Trans Plant: Maint	75	GT Pipeline Reliability	$ 1,187.55
6751342	30724384 - L 126A MP 10.77 REMOVE 6 DRI	GTP26700	Trans Plant: Maint	75	GT Pipeline Reliability	$ 2,525.78
6751362	30755621 - RETIRE 2 VALVES GILROY DFM	GTP26700	Trans Plant: Maint	75	GT Pipeline Reliability	$ 11,742.25
6751375	30765962-302-040 MP 0.00 REPLACE 2500	GTP26700	Trans Plant: Maint	64	GT Gas Gathering System Manage	$ 1,230.15
6740180	30795268-L-210a&b, Mp 22.3 Relocate Sola	GTP26700	Trans Plant: Maint	83	GT WRO	$ 31,586.62
6778303	307A_16.37_Retire 200'	GTP26700	Trans Plant: Maint	75	GT Pipeline Reliability	$ 0.01
6751399	30800171 - RB-54 V-1 VALVE REPL, LEAK (2	GTP26700	Trans Plant: Maint	75	GT Pipeline Reliability	$ 2,330.12
6750755	30814693-L-118, V-81.68 RELOCATE VAULT	GTP26700	Trans Plant: Maint	75	GT Pipeline Reliability	$ 346.12
6751412	30815491 - DFM 7215-01, V-0.96 & V-1.00	GTP26700	Trans Plant: Maint	75	GT Pipeline Reliability	$ 3,620.20
6750300	30815784-1816-15 , Mp 1.61 Install Cp Mi	GTP26700	Trans Plant: Maint	75	GT Pipeline Reliability	$ 2,125.65
6751430	30820545 - SANTA CRUZ HOLDER COMPRESSOR	GTP26700	Trans Plant: Maint	76	GT Station Reliability	$ 28,997.60
6740603	30820594-L-21F&G, MP 8 RELOCATE HWY 101	GTP26700	Trans Plant: Maint	83	GT WRO	$ (514.77)
6743256	30823822-L-150 Im Mp 13.7-18.09 Deactiv	GTP26700	Trans Plant: Maint	75	GT Pipeline Reliability	$ 33,697.25
6751442	30823835 - 0604-24 REMOVE GT V-21 TRAVIS	GTP26700	Trans Plant: Maint	75	GT Pipeline Reliability	$ 7,344.51
6751452	30827767 - DFM 7211-01 RB57 REPL V2,3&6	GTP26700	Trans Plant: Maint	75	GT Pipeline Reliability	$ 1,589.32
6751458	30830361 - DFM 7222-01 V-1.01 LEAK GTLS	GTP26700	Trans Plant: Maint	75	GT Pipeline Reliability	$ 489.11
6751470	30835870 - L-301D, MP 1.71 V-G REPLACEME	GTP26700	Trans Plant: Maint	75	GT Pipeline Reliability	$ (46.04)
6751479	30840751 - MORRO BAY PRIMARY - REPLACE R	GTP26700	Trans Plant: Maint	75	GT Pipeline Reliability	$ 914.29
6751492	30841074 - DREGHORN WALERGA RD DFM UPRAT	GTP26700	Trans Plant: Maint	73	GT Pipeline Capacity	$ 146,460.57

6778237	L-197A TEST MP 13.53-13.55 T-1431	GTP36700	Trans Plant: Main	75	GT Pipeline Reliability	$ 32.80
6773378	L-197C MP 0-8.47 T-1253 CAPITAL	GTP36700	Trans Plant: Main	75	GT Pipeline Reliability	$ (146.55)
6772720	L-197C MP 22.958-23.02 REPL	GTP36700	Trans Plant: Main	75	GT Pipeline Reliability	$ (256.60)
6773379	L-197C MP 8.47-14.73 T-1254 CAPITAL	GTP36700	Trans Plant: Main	75	GT Pipeline Reliability	$ (283.28)
6778731	L-210A MP4.49 Rectifier/Anode replcement	GTP36700	Trans Plant: Main	3K	Gas Trans Remediate Corrosion	$ (3.16)
6776931	L-210B MP 0.075-6.85 T-1288 CAPITAL	GTP36700	Trans Plant: Main	75	GT Pipeline Reliability	$ (400.46)
6775522	L-210C_Mp 22.15 Green Valley Fault	GTP36700	Trans Plant: Main	75	GT Pipeline Reliability	$ (104,237.80)
6791385	L-215/L-215-1 ILI Upgrade Tie-ins	GTP36700	Trans Plant: Main	88	GT Integrity Management	$ (5,055.66)
6758867	L-21E ILI Upgrade MP 114.99-122.54	GTP36700	Trans Plant: Main	88	GT Integrity Management	$ (1.46)
6765282	L-21H MP 0.00- 1.52 ILI Upgrade Receiver	GTP36700	Trans Plant: Main	88	GT Integrity Management	$ (15,943.95)
6780487	L-220 MP 24.6-28.93 T-1405 CAPITAL	GTP36700	Trans Plant: Main	75	GT Pipeline Reliability	$ (120.36)
6782152	L-220 TEST MP 18.31-19.38 CAP	GTP36700	Trans Plant: Main	75	GT Pipeline Reliability	$ (708.73)
6758629	L-220, MP 19.55-19.59	GTP36700	Trans Plant: Main	75	GT Pipeline Reliability	$ (1,214.56)
6536289	L-2403-01 MP 0.01-5.70 DC INTRFNC MITG	GTP36700	Trans Plant: Main	3K	Gas Trans Remediate Corrosion	$ (5,501.44)
6758874	L-2403-12 ILI Upgrade MP 0.00-2.88	GTP36700	Trans Plant: Main	88	GT Integrity Management	$ (10,664.97)
6536288	L-3006-01 MP 0.00-5.75 DC INTRFNC MITG	GTP36700	Trans Plant: Main	3K	Gas Trans Remediate Corrosion	$ (16,364.50)
6768228	L-300A ILI Upgrade	GTP36700	Trans Plant: Main	88	GT Integrity Management	$ 240.67
6765223	L-300A ILI Upgrade MP 0.0 - 40.89	GTP36700	Trans Plant: Main	88	GT Integrity Management	$ (35,367.38)
6765459	L-300A ILI Upgrade MP 21.22 - 40.48	GTP36700	Trans Plant: Main	88	GT Integrity Management	$ (42,588.19)
6765458	L-300A ILI Upgrade MP 21.22A	GTP36700	Trans Plant: Main	88	GT Integrity Management	$ (114,331.49)
6758857	L-300A MP 203.02-256.21	GTP36700	Trans Plant: Main	88	GT Integrity Management	$ (1.68)
6773199	L-300A MP 71.98 L-300B MP 71.96	GTP36700	Trans Plant: Main	75	GT Pipeline Reliability	$ (2,142.49)
6765227	L-300B ILI MP 0.0 - 40.89 Receiver	GTP36700	Trans Plant: Main	88	GT Integrity Management	$ (26,285.67)
6765225	L-300B ILI Upgd MP 0.0 - 40.89 Launcher	GTP36700	Trans Plant: Main	88	GT Integrity Management	$ (25,969.05)
6765091	L-300B ILI UPGRADE 203.07 221.27	GTP36700	Trans Plant: Main	88	GT Integrity Management	$ (0.35)
6765226	L-300B ILI Upgrade MP 0.0 - 40.89	GTP36700	Trans Plant: Main	88	GT Integrity Management	$ (55,875.39)
6768573	L-300B ILI Upgrade MP 103.51 to 161.02	GTP36700	Trans Plant: Main	88	GT Integrity Management	$ (62.98)
6765460	L-300B ILI Upgrade MP 20.84	GTP36700	Trans Plant: Main	88	GT Integrity Management	$ (35,709.52)
6765461	L-300B ILI Upgrade MP 20.84 - 40.89	GTP36700	Trans Plant: Main	88	GT Integrity Management	$ (46,529.62)
6791969	L-300B MP 299.10-299.12 Rplc	GTP36700	Trans Plant: Main	75	GT Pipeline Reliability	$ (33,381.11)
6768132	L-301A ILI Upgrade	GTP36700	Trans Plant: Main	88	GT Integrity Management	$ (123.32)
6785283	L-301A MP 11.098 Capital Replacement	GTP36700	Trans Plant: Main	75	GT Pipeline Reliability	$ 637.92
6775036	L-301A MP 11.46-13.39 T-1199C CAPITAL	GTP36700	Trans Plant: Main	75	GT Pipeline Reliability	$ (1,661.89)
6792380	L-301A MP 2.53-2.62 CALAVERAS FAULT XING	GTP36700	Trans Plant: Main	75	GT Pipeline Reliability	$ (2,803.53)
6776173	L-301B MP 2.49-7.92 T-1283 CAPITAL	GTP36700	Trans Plant: Main	75	GT Pipeline Reliability	$ 830.67
6772679	L-301B MP 7.92-13.96 T-1144 CAPITAL	GTP36700	Trans Plant: Main	75	GT Pipeline Reliability	$ (18.78)
6781400	L-301G MP 24.509 Replace	GTP36700	Trans Plant: Main	75	GT Pipeline Reliability	$ 3,516.20
6758836	L-303 , MP-2.21 RPLC 500 FT ANTIOCH	GTP36700	Trans Plant: Main	83	GT WRO	$ (42,280.49)
6768122	L-307A, 307B & L-134A ILI Upgrade	GTP36700	Trans Plant: Main	88	GT Integrity Management	$ (81.94)
6774741	L-311 MP 0.00-26.17 T-1247 CAPITAL	GTP36700	Trans Plant: Main	75	GT Pipeline Reliability	$ (579.40)
6775441	L-314 Riverside Launch&Receiv MP 24.19	GTP36700	Trans Plant: Main	88	GT Integrity Management	$ (179.41)
6785882	L-400 MP113.88-MP114.07 Replace	GTP36700	Trans Plant: Main	75	GT Pipeline Reliability	$ (270,152.92)
6783805	L-400 Remove DRIP MP 297.86	GTP36700	Trans Plant: Main	3K	Gas Trans Remediate Corrosion	$ (337,403.05)
6784325	L-400 Retire MP 297.79– 297.86	GTP36700	Trans Plant: Main	75	GT Pipeline Reliability	$ (140,874.73)
6783008	L-400-3 ILI Upgr Launcher Montezuma	GTP36700	Trans Plant: Main	88	GT Integrity Management	$ (2,430.12)
6783009	L-400-3 ILI Upgr Receiver Gateway	GTP36700	Trans Plant: Main	88	GT Integrity Management	$ (16,083.08)
6783806	L-400-3 Remove DRIP MP 297.87	GTP36700	Trans Plant: Main	3K	Gas Trans Remediate Corrosion	$ (415,618.21)
6783818	L-400-3 REPL MP 297.82 – 297.88 ILI Upg	GTP36700	Trans Plant: Main	88	GT Integrity Management	$ (49,721.49)
6528868	L-400/401 MP 42.08 - REPLACE XD-DWA	GTP36700	Trans Plant: Main	3K	Gas Trans Remediate Corrosion	$ (12,379.65)
6770199	L-401 ILI Upgrade Receiver	GTP36700	Trans Plant: Main	88	GT Integrity Management	$ 324.50
6538022	L-401 MP 246.59 Casing Remediation	GTP36700	Trans Plant: Main	3K	Gas Trans Remediate Corrosion	$ (58,658.94)
6791220	L-401-1 Replace InOp V-2	GTP36700	Trans Plant: Main	75	GT Pipeline Reliability	$ (1,583.29)
6775288	L-402B ILI Upgrade MP 6.94-13.06	GTP36700	Trans Plant: Main	88	GT Integrity Management	$ (73.35)
6790999	L-404 MP 1.83 REPLACE V-263	GTP36700	Trans Plant: Main	75	GT Pipeline Reliability	$ (17,564.09)
6528234	L101 MP0-44.60 DC Int Mitigation	GTP36700	Trans Plant: Main	3K	Gas Trans Remediate Corrosion	$ (762.14)
6764344	L103 MP 19.60 Rogge Rd Inop V-A-B-C	GTP36700	Trans Plant: Main	75	GT Pipeline Reliability	$ (0.36)
6770438	L109 MP 30.77-43.23 ILI Upgrade	GTP36700	Trans Plant: Main	88	GT Integrity Management	$ (41.98)
6528235	L109 MP0-52.7 DC Int Mitigation	GTP36700	Trans Plant: Main	3K	Gas Trans Remediate Corrosion	$ (10.72)
6767003	L131 MP:28.00-31.83 Rplc 24-in, Vintage	GTP36700	Trans Plant: Main	75	GT Pipeline Reliability	$ (19,485.34)
6770244	L137C[_]8.30[_]Relocate Pipe	GTP36700	Trans Plant: Main	75	GT Pipeline Reliability	$ 2,388.48
6528236	L153 MP0-27.88 DC Int Mitigation	GTP36700	Trans Plant: Main	3K	Gas Trans Remediate Corrosion	$ (10.94)
6528237	L153 MP18.77-22.75 DC Int Mitigation	GTP36700	Trans Plant: Main	3K	Gas Trans Remediate Corrosion	$ (284.32)
6768239	L300A, L-300B, L312 WRO (HWY 58 reroute)	GTP36700	Trans Plant: Main	83	GT WRO	$ 15,428.32
6762181	L50A MP 31.64 Leak Repair	GTP36700	Trans Plant: Main	75	GT Pipeline Reliability	$ 405.13
6782385	Las Vinas Station Replace Inop V-72	GTP36700	Trans Plant: Main	75	GT Pipeline Reliability	$ (106.84)
6525810	Line 002 MP 43.6 Rectifier Replacement	GTP36700	Trans Plant: Main	3K	Gas Trans Remediate Corrosion	$ (12.02)
6777758	LINE 177A MP 176.3 Casing Remediation	GTP36700	Trans Plant: Main	3K	Gas Trans Remediate Corrosion	$ 626,731.08
6530383	LVCR Rebuild 1030-01 MP 1.09	GTP36700	Trans Plant: Main	76	GT Station Reliability	$ (273.58)
6765629	McD Jc. Replace V-5 & V-6	GTP36700	Trans Plant: Main	76	GT Station Reliability	$ (24.09)
6774130	Monterey Reg Sta, Figueroa & Franklin St	GTP36700	Trans Plant: Main	75	GT Pipeline Reliability	$ (408.02)
6527099	MORRO BAY PRIMARY & MM REMOVAL - Phase 1	GTP36700	Trans Plant: Main	75	GT Pipeline Reliability	$ (864.70)
6763570	OCW - LAWNDALE & MISSION SOUTH SAN FRAN	GTP36700	Trans Plant: Main	3K	Gas Trans Remediate Corrosion	$ (4,020.49)
6733801	P.02962-L-177A ILI UPGRADE	GTP36700	Trans Plant: Main	88	GT Integrity Management	$ 12,313.21
6723899	P.02978-L124A MP 0 TO 26_27 ILI UPGRADE	GTP36700	Trans Plant: Main	88	GT Integrity Management	$ 25,529.60
6748981	P.03559-LTIMP Capital overall scope	GTP36700	Trans Plant: Main	75	GT Pipeline Reliability	$ 1,415.73
6723868	P.03638-L-105N ILI MP 7.75 to 22.85 Upgr	GTP36700	Trans Plant: Main	88	GT Integrity Management	$ 167,542.26
6750364	P.03639-VTA - BART Gas Transmission Capi	GTP36700	Trans Plant: Main	83	GT WRO	$ 2,081.40
6742736	P.04064 L-109 4A_1 REPL 6.23MI MP 24.84-	GTP36700	Trans Plant: Main	2H	GT PL Safety Enhance Plan-Cap	$ (4,464.03)
6505679	Pipeline Integrity Management Program	GTP36700	Trans Plant: Main	88	GT Integrity Management	$ 7,944.43
6511759	Pipeline RIM Projects	GTP36700	Trans Plant: Main	88	GT Integrity Management	$ 26,704.97
6758664	PLS 4A & 4B	GTP36700	Trans Plant: Main	76	GT Station Reliability	$ (16,634.57)
6766399	Port Costa Reg Sta Rplc V-10 InOp	GTP36700	Trans Plant: Main	75	GT Pipeline Reliability	$ (27,219.84)
6766166	R-008B L-108 MP 39.01-40.27	GTP36700	Trans Plant: Main	75	GT Pipeline Reliability	$ 14,250.08
6778304	R-1037 1509-04 MP 1.58-1.81 Replace	GTP36700	Trans Plant: Main	75	GT Pipeline Reliability	$ (0.49)
6782219	R-1185 DFM-611-17 MP 0.00-0.21 Replace S	GTP36700	Trans Plant: Main	75	GT Pipeline Reliability	$ (48.60)
6791970	R-1403 DFM-2408-05 MP 4.71 Replace Pipe	GTP36700	Trans Plant: Main	75	GT Pipeline Reliability	$ (1,358,284.87)
6752918	R-185 L-109_4A_2 1.19MI MP 28.60-29.60 P	GTP36700	Trans Plant: Main	2H	GT PL Safety Enhance Plan-Cap	$ (2,037.28)
6758488	R-401 DFM 0208-01 0.75MI MP1.77-2.48 RPL	GTP36700	Trans Plant: Main	73	GT Pipeline Capacity	$ (267.69)
6768242	R-445 L-177A Relocate Hamilton City Leve	GTP36700	Trans Plant: Main	83	GT WRO	$ (290.60)
6765344	R-649 L-131 0.14MI MP 31.83-32.38 REPLAC	GTP36700	Trans Plant: Main	75	GT Pipeline Reliability	$ (1,349.52)
6778282	R-839 DFM 0606-02 RETIRE MP 1.07 - 3.03	GTP36700	Trans Plant: Main	75	GT Pipeline Reliability	$ 0.87
6786279	RCEQ L-311 MP 48.5 Replacement (75L)	GTP36700	Trans Plant: Main	3Q	Catastrophic Events	$ (10,389.29)
6786278	RCEQ L-372 MP 2.34 Replacement (75L)	GTP36700	Trans Plant: Main	3Q	Catastrophic Events	$ (5,966.58)
6772541	Railez Sta Rd Reg Sta L-191-1 MP 25.3	GTP36700	Trans Plant: Main	75	GT Pipeline Reliability	$ (696,764.49)
6786438	Remove 16-in Deactivated Pipe - 23rd St	GTP36700	Trans Plant: Main	83	GT WRO	$ (120,035.56)
6763567	REPAIR RECTIFIER CURRENT L108, MP 47.0	GTP36700	Trans Plant: Main	3K	Gas Trans Remediate Corrosion	$ (1,168.65)
6764620	REPAIR RECTIFIER, CURRENT, L301A & G, DO	GTP36700	Trans Plant: Main	3K	Gas Trans Remediate Corrosion	$ (854.29)
6776924	RT-742 GCUST5969 0.18-0.22 REPL	GTP36700	Trans Plant: Main	75	GT Pipeline Reliability	$ (805.33)
6783578	RT-751 DFM-1611-03 MP 0.24, 0.43, & 4.29	GTP36700	Trans Plant: Main	75	GT Pipeline Reliability	$ 6,754.20
6768867	RT-805 GCUST5950 MP 0.00 REPLACE	GTP36700	Trans Plant: Main	75	GT Pipeline Reliability	$ 352.88
6778388	RT-811 STUB10814 MP 0.00-0.0004 Replace	GTP36700	Trans Plant: Main	75	GT Pipeline Reliability	$ (1,809.00)
6773666	RT-844 L-21E MP80.36 SITE33 ILI CUT OUT	GTP36700	Trans Plant: Main	75	GT Pipeline Reliability	$ 0.04
6778020	S-ECA1 STA 389 METZ_RD Repair	GTP36700	Trans Plant: Main	76	GT Station Reliability	$ (753.86)
6782155	S-ECA1 STA609 ROAD_61	GTP36700	Trans Plant: Main	76	GT Station Reliability	$ (8,911.18)
6785911	STA10971 MP 0 REP	GTP36700	Trans Plant: Main	75	GT Pipeline Reliability	$ (200.00)
6784118	T-1398B L-105A 41.86-48.73 Test Cap	GTP36700	Trans Plant: Main	75	GT Pipeline Reliability	$ (2,460.32)
6534519	T-1398C L-105A 48.73-52.04 Test Cap	GTP36700	Trans Plant: Main	75	GT Pipeline Reliability	$ (3,089.69)
6782134	T-1430 L-181B TEST MP 4.08-7.06 CAP	GTP36700	Trans Plant: Main	75	GT Pipeline Reliability	$ 3,013.80
6545619	T-1431 DREG4714 MP 0.065-0.075 CAPITAL	GTP36700	Trans Plant: Main	75	GT Pipeline Reliability	$ (42,729.13)
6782643	T-1435 GCUST5918 MP 0.00 - 0.02 TEST CAP	GTP36700	Trans Plant: Main	75	GT Pipeline Reliability	$ (19,800.05)
6788499	T-1476 GCUST5813 MP 1.405 - 1.46 TEST CA	GTP36700	Trans Plant: Main	75	GT Pipeline Reliability	$ (5,874.86)
6788849	T-1507 L-401 MP185.71-186.49 Test Capita	GTP36700	Trans Plant: Main	75	GT Pipeline Reliability	$ (6,880.52)
6758720	Topock x-tie, Suction PRV"s, TW-1 OPP	GTP36700	Trans Plant: Main	76	GT Station Reliability	$ 549.12
6765697	V-247 Valve Auto - L-134A MP 6.15	GTP36700	Trans Plant: Main	75	GT Pipeline Reliability	$ (0.01)
6765698	V-248 Valve Auto - L-134A MP 10.93	GTP36700	Trans Plant: Main	75	GT Pipeline Reliability	$ (12.08)
6778906	V-254B L-021F Stone Dr Vault Removal	GTP36700	Trans Plant: Main	75	GT Pipeline Reliability	$ (2,547.14)
6758343	Valve Auto - Rousseau	GTP36700	Trans Plant: Main	75	GT Pipeline Reliability	$ (1.76)
6754441	VALVE AUTO-ADOBE	GTP36700	Trans Plant: Main	75	GT Pipeline Reliability	$ (2,655.69)
6754450	VALVE AUTO-L021A, MP16.16	GTP36700	Trans Plant: Main	75	GT Pipeline Reliability	$ (367.46)
6754541	VALVE AUTO-L300B, MP455.208	GTP36700	Trans Plant: Main	75	GT Pipeline Reliability	$ (606.86)
6754544	VALVE AUTO-L402 MP14.76	GTP36700	Trans Plant: Main	75	GT Pipeline Reliability	$ 0.01
6754562	VALVE AUTO-US101 & OLD REDWOOD HWY	GTP36700	Trans Plant: Main	75	GT Pipeline Reliability	$ (2,597.70)
6756798	WALNUT CROSSOVER REBUILD BALIP	GTP36700	Trans Plant: Main	75	GT Pipeline Reliability	$ 18.89
6530212	Westend Primary Replace Filters	GTP36700	Trans Plant: Main	75	GT Pipeline Reliability	$ (88.19)
6790300	X6526 MP 0.00-0.270 TEST CAPITAL	GTP36700	Trans Plant: Main	75	GT Pipeline Reliability	$ (6,123.96)
Overall Result						###########

Journal Entries:

	2011-2014 GT&S COST OF REMOVAL PUSHED DOWN TO SUBLEDGER	$ (6,064,949.00)
Total		$ (35,944,787.96)

AccountNumber	TransactionCode	TransactionYear	InstallationYear	RetirementAmount	AdjustedTY	RemovalCost	SalvageReuse	SalvageFinal	Explanation
36700	0	2011		-	-	12,834,813.66		-	Includes portion of recorded $6.1M in cost of removal that was disallowed
36700	0	2012		-	-	24,479,475.27		-	Includes portion of recorded $6.1M in cost of removal that was disallowed
36700	0	2013		(6,479,369.83)	-	21,280,988.89		-	Includes portion of recorded $6.1M in cost of removal that was disallowed
36700	0	2014		(11,879,913.50)	-	12,546,033.31		(0.50)	Includes portion of recorded $6.1M in cost of removal that was disallowed
36700	0	2016				23,653,853.03			Includes portion of recorded $6.1M in cost of removal that was disallowed
36700	0	2016				(2,328,723.00)			GT&S Capex Disallowance - Total of $6.1M - HL entry to record disallowance
36700	0	2016				(3,736,226.00)			GT&S Capex Disallowance - Total of $6.1M - HL entry to record disallowance
36700	0	2016				2,328,723.00			GT&S Capex Disallowance - Total of $6.1M - GF entry to exclude from net salvage analysis
36700	0	2016				3,736,226.00			GT&S Capex Disallowance - Total of $6.1M - GF entry to exclude from net salvage analysis
36700	0	2020				6,064,949.00			Reversal of $6.1M High Level Disallowance to be recorded to subledger
36700	0	2020				29,879,838.96			2020 COR recorded to subledger - Includes negative $6.1M disallowance

AccountNumber	TransactionCode	TransactionYear	InstallationYear	RetirementAmount	AdjustedTY	RemovalCost	SalvageReuse	SalvageFinal	Explanation
36400	0	2019		(19,463,468.93)		91,503,322.22		-	Includes recorded $3.2 million COR that will be written off (positive $3.2 million amount
36400	0	2019		19,540.75		(3,159,798.49)			Includes write-off of $3.2 million COR (negative amount)
36400	0	2020		(11,732,202.54)		13,463,239.64			$13.5 million amount includes reversal of high-level $3.2 million write-off (positive amount
36400	0	2020		(33,509,369.48)		138,326,124.25		-	$138.3 million includes write-off (negative amount)

PACIFIC GAS AND ELECTRIC COMPANY
2023 General Rate Case Phase I
Application 21-06-021
Data Response

PG&E Data Request No.:	CalAdvocates_236-Q002		
PG&E File Name:	GRC-2023-PhI_DR_CalAdvocates_236-Q002		
Request Date:	January 20, 2022	Requester DR No.:	PubAdv-PG&E-236-ANU
Date Sent:	February 9, 2022	Requesting Party:	Public Advocates Office
PG&E Witness:	Beatrix Greenwell (all) Ned Allis (b)	Requester:	Anusha Nagesh

SUBJECT: FOLLOW-UP TO DR-116-ANU, Q.04.F AND Q.02.F (DEPRECIATION STUDY IMPACT)

QUESTION 002

In response to PubAdv-PG&E-016-ANU, Q.02.f, PG&E provided a document titled "GRC-2023- PhI_DR_CalAdvocates_016-Q01Atch11." Refer to tab "EDP36400," cell G1267, PG&E includes "WILDFIRE OII COST OF REMOVAL WRITE-OFF" adjustment of -$3,159,798 to cost of removal in recorded year 2019. Answer the following questions:

a. Explain in detail all the transactions in a timeline along with the corresponding dollar amount to show the initial removal entry in cost of removal, corresponding credit entry in rate base and reversal entry in cost of removal for all the impacted recorded years to prove this transaction is not a duplicate entry.

b. With reference to response in Q2.a, explain in detail why each transaction occurred and how it impacts the future net salvage forecast for TY 2023.

c. Identify all journal entries, associated documents in chronological order for this transaction to show the initial removal entry in cost of removal, corresponding credit entry in rate base and reversal entry in cost of removal for all the impacted recorded years corresponding to the amount identified in Q2.a above.

ANSWER 002

a. Please see GRC-2023-PhI_DR_CalAdvocates_236-Q002Atch01, for the requested details to demonstrate that the Wildfire OII cost of removal adjustment of -$3,159,798 is not a duplicate entry.

Overview of Recording Entries:

1. Record amounts to plant and cost of removal (accumulated depreciation) within the subledger (PowerPlan).
2. Commission decision received; PG&E records plant and cost of removal disallowance. Write off estimated capital disallowance to high level general ledger account(s) (SAP).
3. Reverse the disallowance in the high level general ledger account(s) (SAP).

4. Record the disallowance to the individual capital orders within the subledger (PowerPlan).

Detailed Description:

The following is a detailed description of the transactions in the timeline, including references to the attachment for each step.

i. Recorded order costs would exist on the books, including a plant balance and a cost of removal balance. Cost of removal is included in the accumulated depreciation (A/D) balance. These recorded costs would both be debits, or positive amounts which increase rate base.

ii. Upon receiving a Commission decision to disallow plant, record an initial entry per the Commission order to disallow plant and cost of removal. That entry is a credit to the plant and A/D accounts, and a debit to record the loss. The credit entries to plant and A/D reduce rate base. This initial entry is recorded to SAP general ledger accounts and asset classes as estimated initial amounts.
   - Attachment reference: See Tab “1 Summary”, line 1. Please refer to column “1080115 Accum Dep- Accrl” for the cost of removal related journal entry amounts. This initial entry 1002516601 was recorded in December 2019, and includes the referenced ($3,159,798).
   - See Tab 3.1 “COR by Asset Class” which provides the high level entry dollar amounts and assigned asset classes. Line 1 shows the cost of removal disallowance amount of ($3,159,798) assigned to asset class EDP36400, with a total high level journal entry amount of ($6,761,446).
   - Detailed journal entries have been included as tabs 4-12, with the document number in tab name (see section iii below). See Tab “4 1002516601”. The cost of removal disallowance amounts of ($4,425,641) and ($2,335,805) totals the ($6,761,446) disallowance amount provided in Tab “1, Summary” for this high level journal entry.

iii. Subsequent additions and subtractions may be made based on additional analysis or changing capital order totals, adding to, or subtracting from ii. above.
   - Attachment reference: See Tab “1 Summary”, lines 2-6. Please refer to column “1080115 Accum Dep- Accrl” for the cost of removal related amounts. These subsequent entries were recorded in March, June and September of 2020.
   - Detailed journal entries have been included as tabs 4-12, with the document number in tab name.
   - Attachment reference: The total journal entries for cost of removal can be found in Tab 1, Line 7, column “1080115 Accum Dep-Accrl” as the total high levels of ($4,362,033).

iv. The final stage is to "push down" the entries. What this means is to reverse the high level general ledger entry and replace it with entries in the subledger to specific plant accounts, vintages, etc. The subledger will then contain the disallowance amount. This is essentially a reclassification of where the costs reside.
  - The entries in ii. and iii. are reversed.
    - Attachment reference: See Tab "1 Summary", line 9. Please refer to column "1080115 Accum Dep- Accrl" for the cost of removal related reversal amounts. The total reversal can be found in Line 12 of this column, $4,362,033. The $4,362,033 reversal entry was recorded in September 2020.
    - Note that the line 13 total shows that lines 7 and 12 net to zero.
    - The initial entries in ii. and the reversals in iii. can also be seen in "3.1 COR by Asset Class", on rows 8 and 14, respectively.
    - The offset credit is to account 5590049 which functions as a clearing account in conjunction with the subledger.
  - PG&E's subledger is called PowerPlan. The credits to plant and cost of removal (A/D) are recorded in the subledger. The "push down" to the subsidiary ledger occurred in October 2020.
    - Attachment reference: See tabs "2 COR report by Asset Class" totaling $4,380,681 and "3 Order charges report", line 7, totaling $4,362,033.
    - Because the disallowance is recorded to orders, the final cost of removal amount may differ slightly. In this case, the cost of removal disallowance difference is $18,648.
    - The debit offset is in the subledger and is recorded in account 5590049 which functions as a clearing account

b. PG&E interprets "future net salvage forecast for TY 2023" to be in reference to the net salvage estimates recommended by Mr. Allis in the depreciation study, which will be incorporated into the TY 2023 revenue requirement. Please see Attachment GRC-2023-PhI_DR_CalAdvocates_236-Q001Atch02 for the records from the net salvage data associated with the transactions in Q1.a. Each of these transactions were included in the net salvage data. While the considerations discussed in the response to Q2.b apply, the disallowance amount for this account is small when compared to the overall cost of removal in the historical data of $643.5 million and so the disallowance does not materially impact Mr. Allis's proposed (175) percent net salvage estimate, which is less negative than the indications from the historical data.

c. See the response to subpart a.

PACIFIC GAS AND ELECTRIC COMPANY

APPENDIX C

GRC-2023-PHI_DR_CALADVOCATES_236-Q002ATCH01

THIS ATTACHMENT IS AVAILABLE ELECTRONICALLY AS AN EXCEL DUE TO THE SIZE. PLEASE SEE ZIP FILE "EXHIBIT 23 APPENDIX C – DISCOVERY ATTACHMENTS" ON PG&E'S PUBLIC CASE DOCUMENT SITE

PACIFIC GAS AND ELECTRIC COMPANY
2023 General Rate Case Phase I
Application 21-06-021
Data Response

PG&E Data Request No.:	CalAdvocates_237-Q001		
PG&E File Name:	GRC-2023-PhI_DR_CalAdvocates_237-Q001		
Request Date:	January 20, 2022	Requester DR No.:	PubAdv-PG&E-237-ANU
Date Sent:	February 9, 2022	Requesting Party:	Public Advocates Office
PG&E Witness:	Beatrix Greenwell	Requester:	Anusha Nagesh

SUBJECT: FOLLOW-UP TO DR-116-ANU, Q.04.F AND Q.02.F (RATE BASE IMPACT)

QUESTION 001

In response to PubAdv-PG&E-016-ANU, Q.04.f, PG&E provided a document titled "GRC-2023- PhI_DR_CalAdvocates_016-Q01Atch12." Refer to tab "GTP36700_GTP36703," cell G710. PG&E includes "2011-2014 GT&S COST OF REMOVAL PUSHED DOWN TO SUBLEDGER" adjustment of -$6,064,949 to cost of removal in recorded year 2020. Answer the following questions:

a. Explain in detail all the transactions in a timeline along with the corresponding dollar amount to show the initial removal entry in cost of removal, corresponding credit entry in rate base and reversal entry in cost of removal for all the impacted recorded years to prove this transaction is not a duplicate entry.

b. With reference to response to Q1.a above, explain in detail why these transactions occurred and how it impacts all associated recorded years' and forecasted TY 2023' Rate Base.

c. Identify all journal entries, associated documents in chronological order for this transaction to show the initial removal entry in cost of removal, corresponding credit entry in rate base and reversal entry in cost of removal for all the impacted recorded years corresponding to the amount identified in Q1.a above.

ANSWER 001

a. Please see GRC-2023-PhI_DR_CalAdvocates_236-Q001 subpart a.

b. Please see the response to GRC-2023-PhI_DR_CalAdvocates_236-Q001 for transaction information and years that each transaction is recorded. Amounts recorded as of December 31, 2020 including these transactions are included in rate base in PG&E's 2023 GRC as the recorded base year starting point.

c. Please see GRC-2023-PhI_DR_CalAdvocates_236-Q001 subpart c.

PACIFIC GAS AND ELECTRIC COMPANY
2023 General Rate Case Phase I
Application 21-06-021
Data Response

PG&E Data Request No.:	CalAdvocates_237-Q002		
PG&E File Name:	GRC-2023-PhI_DR_CalAdvocates_237-Q002		
Request Date:	January 20, 2022	Requester DR No.:	PubAdv-PG&E-237-ANU
Date Sent:	February 9, 2022	Requesting Party:	Public Advocates Office
PG&E Witness:	Beatrix Greenwell	Requester:	Anusha Nagesh

SUBJECT: FOLLOW-UP TO DR-116-ANU, Q.04.F AND Q.02.F (RATE BASE IMPACT)

QUESTION 002

In response to PubAdv-PG&E-016-ANU, Q.02.f, PG&E provided a document titled "GRC-2023- PhI_DR_CalAdvocates_016-Q01Atch11." Refer to tab "EDP36400," cell G1267, PG&E includes "WILDFIRE OII COST OF REMOVAL WRITE-OFF" adjustment of -$3,159,798 to cost of removal in recorded year 2019. Answer the following questions:

a. Explain in detail all the transactions in a timeline along with the corresponding dollar amount to show the initial removal entry in cost of removal, corresponding credit entry in rate base and reversal entry in cost of removal for all the impacted recorded years to prove this transaction is not a duplicate entry.

b. With reference to response to Q2.a above, explain in detail why these transactions occurred and how it impacts all associated recorded years' and forecasted TY 2023' Rate Base.

c. Identify all journal entries, associated documents in chronological order for this transaction to show the initial removal entry in cost of removal, corresponding credit entry in rate base and reversal entry in cost of removal for all the impacted recorded years corresponding to the amount identified in Q2.a above.

ANSWER 002

a. Please see GRC-2023-PhI_DR_CalAdvocates_236-Q002 subpart a.

b. Please see the response to GRC-2023-PhI_DR_CalAdvocates_236-Q002 for transaction information and years that each transaction is recorded. Amounts recorded as of December 31, 2020 including these transactions are included in rate base in PG&E's 2023 GRC as the recorded base year starting point.

c. Please see GRC-2023-PhI_DR_CalAdvocates_236-Q002 subpart c.