PUBLIC VERSION

PREPARED DIRECT TESTIMONY OF

SAMUEL GOLDING

BEFORE THE PUBLIC UTILITIES COMMISSION

OF THE STATE OF CALIFORNIA

SEPTEMBER 25, 2026

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I. INTRODUCTION TO WITNESS

Q. Mr. Golding, would you please state your name, business address, and occupation?

A. My name is Samuel Nash Vautier Golding. My business address is 120 Pulpit Hill Road, Unit 28, Amherst, MA 01002. I am the president of Community Choice Partners, LLC, a consultancy that specializes in the design and operation of power enterprises operating in competitive markets and is dedicated to maximizing democratic, informed decision-making in the energy industry. Our clients reflect the diversity of the energy industry and have included city and county governments, municipal and investor-owned utilities, Community Choice Aggregation (CCA) joint powers agencies, energy technology and software companies, labor unions and electrical contractor associations, and a variety of consumer advocate, environmental and social justice nonprofits.

Q. On whose behalf are you testifying in this proceeding?

A. I am testifying on behalf of the Utility Consumers' Action Network ("UCAN"), a nonprofit ratepayer advocacy organization representing residential and small commercial customers in the service territory of San Diego Gas & Electric Company ("SDG&E").

Q. Please summarize your qualifications and experience.

A. I received an undergraduate degree in International Political Economy from Colorado College in 2006. I entered the utility industry in 2007 with responsibilities that focused on evaluating the performance of demand-side management programs, conducting electricity and natural gas demand-side management and demand response potential studies at the utility and state territory levels, tracking hundreds of distributed energy resource technologies and customer-facing smart grid applications emerging across organized electricity markets, and contributing to "Utility of the Future" strategies. In 2011, I became the managing director of the consultancy that originally created CCA, and I founded Community Choice Partners in 2013. Based on my professional experience designing and operating CCA agencies, I created the "CCA 2.0" and "CCA 3.0" maturity models for the industry, and in New Hampshire I designed, implemented and launched the Community Power Coalition of New Hampshire (CPCNH), a joint powers agency for which I authored the governance documents, the business plan and its accompanying energy and financial cost-of-service and cash-flow model, and the competitive solicitations for comprehensive services and credit support, and for which I evaluated proposals and structured and negotiated the resulting service contracts.

I have supported UCAN's engagement in the Order Instituting Rulemaking to Review, Revise, and Consider Alternatives to the Power Charge Indifference Adjustment (R.17-06-026); the Application of San Diego Gas & Electric Company for Approval of its 2021 Electric Procurement Revenue Requirement Forecasts and GHG-Related Forecasts (A.20-04-014); the Order Instituting Rulemaking to Establish Policies, Processes, and Rules to Ensure Reliable Electric Service in California in the Event of an Extreme Weather Event in 2021 (R.20-11-003); the Order Instituting Rulemaking to Modernize the Electric Grid for a High Distributed Energy Resources Future (R.21-06-017); the Order Instituting Rulemaking to Advance Demand Flexibility Through Electric Rates (R.22-07-005); and the Order Instituting Rulemaking to Consider Distributed Energy Resource Program Cost-Effectiveness Issues, Data Use and Access, and Equipment Performance Standards (R.22-11-013).

My professional experience that is most directly relevant to this testimony includes: (1) the design, issuance and evaluation of competitive solicitations for multi-year service contracts on behalf of a load-serving entity, including the retail data management, billing and customer service functions that depend on utility meter data; (2) the development and maintenance of probabilistic cost-of-service and cash-flow models used to set rates, budget, and support credit evaluations for CCA agencies in California (Sonoma Clean Power, the City of San Francisco, the City of Long Beach, and the County of San Diego) and New Hampshire; (3) the receipt and analysis of confidential interval meter data on behalf of CCAs and municipalities in the PG&E, SCE and SDG&E service territories, and the preparation of Commission filings on behalf of UCAN detailing the ways in which the investor-owned utilities do not provide interval usage data to CCAs on an operational or planning basis; and (4) the evaluation of utility general rate case and Grid Modernization proposals on behalf of CCAs and ratepayer advocates. Attachment SG-1 summarizes my qualifications and experience.

Q. Have you previously submitted testimony in regulatory proceedings?

A. Yes. Before this Commission, I submitted prepared direct testimony on behalf of UCAN in A.20-04-014 (SDG&E's 2021 Energy Resource Recovery Account forecast) and direct and reply testimony on behalf of UCAN in R.20-11-003 (the Commission's rulemaking on resource adequacy and related market design). Before the New Hampshire Public Utilities Commission, I submitted direct and rebuttal testimony in Docket No. DE 19-197 on the development of a statewide, multi-use online energy data platform, testimony in Docket No. DE 24-112 regarding Eversource's proposal to recover default service over- and underrecoveries from all distribution customers, and testimony on behalf of CPCNH in Docket No. DE 24-065 regarding Unitil's 2024 default service solicitations.

II. OVERVIEW OF TESTIMONY

Q. What is the purpose of your testimony?

A. UCAN asked me to review SDG&E's Application for approval of its Smart Meter 2.0 ("SM 2.0") proposal, the supporting testimony and workpapers, and the discovery record, and to address four questions within the scope of this proceeding: (1) whether SDG&E has shown that a four-year mass deployment beginning immediately after a final decision is the least-cost, least-risk strategy for replacing its first-generation advanced metering system, and whether mass deployment should instead be conditioned on Commission review of the results of an initial phase (Scoping Memo Issues 2(e), 2(f) and 2(i)); (2) whether the proposed two-way Advanced Metering Infrastructure Balancing Account ("AMIBA") and the treatment of recurring software and connectivity charges are reasonable (Issues 3 and 4); (3) whether the Application apportions costs between gas and electric ratepayers commensurate with the benefits each receives (Issue 2(k)); and (4) what functional conditions the Commission should attach to any authorization so that ratepayers receive value for what they are asked to pay (Issues 2(g), 2(l) and 5).

Q. Please summarize your conclusions.

A. SDG&E asks the Commission to authorize approximately $825 million of capital and operating expense for 2024 through 2031,[1] producing a revenue requirement of $1,325.5 million through 2071,[2] to replace 1.63 million electric meters and 0.95 million gas modules on a four-year schedule.[3] My review leads me to five conclusions.

First, the Application does not meet the standard the Commission set for it. D.24-12-074 denied SDG&E's prior request for reasons including that SDG&E had not provided "a comprehensive cost-benefit analysis comparing various replacement strategies,"[4] and directed that any renewed request assess "long-term viability, the potential for stranded assets, and whether a competitive procurement process would have yielded a better outcome."[5] SDG&E has now confirmed in discovery that, for the cost of operating two head-end systems in parallel, it "did not assess alternative scenarios such as a smaller pilot, slower or phased deployment" (see Section IV.D),[6] that it "has not prepared, and is not aware of, any separate comprehensive quantitative cost analysis comparing alternative deployment timing, deployment sequencing, deployment phasing, or sourcing strategies"

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[1] Ex. SDG&E-01 at DG-4, lines 15–17; Ex. SDG&E-06 at CWB-4, Table 6-2; see Ex. SDG&E-03 at DT/BB-15, Table 3-1 and lines 10–11 ($762.0 million of escalated direct costs, including contingency, before overheads, AFUDC and capitalized property tax).
[2] Ex. SDG&E-06 at CWB-7, Table 6-4.
[3] Ch. 3 Workpaper 1, notes A29–A30.
[4] D.24-12-074, Finding of Fact 317 at 1010; see id. at 672 (declining the project "for various reasons").
[5] D.24-12-074 at 675.
[6] Response to CalAdv DR-005, Q22 (question) and Q22.b (answer, quoted in full in Section IV.D, referring for delayed-start scenarios to Ex. SDG&E-03 at DT/BB-36 to DT/BB-39). The "initial deployment" stage of SDG&E's plan is a ramp within the same schedule, about 5 percent of replacements before mass deployment, with no Commission checkpoint: Ex. SDG&E-04 at BB/DC/DH-8, lines 11–20; Response to CalAdv DR-004, Q4.a and Q4.c.i.

to its plan,[7] and that the only delay comparison it offers, Table 3-10, is stated in escalated nominal dollars,[8] with no present-value analysis in the supporting workpaper.[9]

Second, the failure forecast on which the schedule rests has not been back-tested or validated in any document SDG&E has produced, and it is already diverging from SDG&E's actual experience. SDG&E's electric model compounds a 2021–2025 growth rate without bound, producing annual failure rates that exceed 100 percent for a third of the fleet by 2033–2035; its gas model assigns every module a mandatory monthly voltage decline and an aging term regardless of its observed voltage history, so that, for a module whose voltage is flat, rising or declining more slowly than the floor, whether it is forecast to survive depends on its starting margin above the failure threshold, not on its history.[10] Actual electric failures on the monthly series produced to UCAN were 33,307 in 2024, 37,370 in 2025 and about 34,700 on an annualized basis through July 2026, and actual gas failures are running at less than one percent of the fleet per year on either of SDG&E's series;[11] the forecast calls for 57,000 electric failures in 2026 rising to 136,000 in 2031,

[7] Response to UCAN DR-02, Q3.
[8] Ex. SDG&E-03 at DT/BB-37, Table 3-10 (total direct costs of $1,021.4 million and $1,123.3 million against $762.0 million, that is, $259 million and $361 million of additional direct cost for a 2031 or 2032 start, of which $71.3 million and $86.9 million is escalation of SM 2.0 costs and the balance incremental SM 1.0 cost); Response to CalAdv DR-002, Q4.k (the $71.3 to $86.9 million "does not represent the incremental cost of delaying SM 2.0 deployment" but "reflect[s] the increase in SM 2.0 costs caused by inflation and other escalation factors").
[9] Ch. 3 Workpaper 3, tab "WP 3.10.1" (no annual cash flows and no discounting).
[10] Response to UCAN DR-02, Q5.a–c (SDG&E does not calculate the number of modules whose forecast decline is set by the VDropMax floor rather than by observed history, Q5.a).
[11] Response to UCAN DR-02, Q4, attachments "UCAN-SDGE-DR-002 Q4.i.xlsx" (electric) and "Q4.ii.xlsx" (gas) (SDG&E notes that the counts are based on last-read-time data and that "reruns using the same methodology may produce different counts"). SDG&E's annual counts in Response to SBUA DR-003, Q8(a), are 34,856 (2024), 38,750 (2025) and 19,493 (January through June 2026) for electric meters and 7,618, 8,811 and 4,050 for gas modules; the difference from the monthly series reflects the timing of the thirty-day non-communication classification and the device-population corrections SDG&E describes in Q4. Either series is below the forecast of 43,000 electric failures for 2025 and 57,000 for 2026. Replacement counts (Response to CalAdv DR-006 Part 1, Q58.a) include growth and damage and are not failure counts.

and a gas "cliff" of 193,000 to 274,000 per year in 2030–2032.[12] The forecast is the basis for the deployment schedule, for the urgency claimed in the Application, and for roughly $420 million of revenue requirement assigned to gas ratepayers through 2071.

Third, using SDG&E's own unit costs, escalation, financing parameters and failure forecast, a deployment that replaces meters as they fail and proactively sweeps the one cohort with a known manufacturing defect, with a Commission checkpoint before any mass deployment, has a lower present-value cost than the Application's schedule under every failure path I tested: roughly $12 million lower (1 percent) on SDG&E's own forecast and roughly $92 million lower (10 percent) on the trend of SDG&E's actuals. That structure is based on SDG&E's [Confidential Information Begins] ………………………… ………………………………………………………………………………………… ………………………………………………………………………………………… .... [Confidential Information Ends].

Fourth, the cost recovery design shifts risk to ratepayers without a corresponding obligation. The AMIBA would true up to an "authorized amount" that SDG&E has not defined by cost category or as an annual or program total, with no defined process for costs above it, no milestone gating, no cost sharing and no periodic reporting beyond the annual advice-letter update of the account balance[13] and no protection against early retirement.[14] Separately, SDG&E's own cost workbooks compute recurring connectivity, head-end software and capability subscription charges of approximately $426 million from 2027

[12] Ex. SDG&E-02 at SB-8, Figure 2-3.
[13] Response to UCAN DR-02, Q14.a–c; Ex. SDG&E-06 at CWB-7, Table 6-4, and CWB-11, lines 4–11.
[14] Response to UCAN DR-02, Q13.a.

through 2044, of which only $63 million, the five-year prepayments booked in 2027, is in the Application;[15] the prepayments cover connectivity "only through 2031,"[16] and the remaining $359 million, none of it disclosed in the testimony, falls after 2031, in a period SDG&E says "would be addressed in a future GRC or other appropriate regulatory proceeding."[17]

Fifth, the split of the revenue requirement between gas and electric ratepayers cannot be reproduced from the allocation factors SDG&E says it used.[18] Applying SDG&E's own factors to SDG&E's own cost categories yields a gas share of about 26 to 28 percent ($341 to $371 million);[19] the Application assigns 31.7 percent ($420.4 million).[20] SDG&E has declined to produce the model in which the allocation was performed.[21] A benefit-based allocation, assigning every identifiable cost directly and splitting the shared platform by endpoint counts, yields a gas share of about 27 percent and assigns none of the "NextGen Enhanced Electric Capabilities" to gas ratepayers, who, as SDG&E acknowledges, receive no customer-facing functionality from them (see Section VI).[22]

Q. Please summarize your recommendations.

A. I recommend that the Commission:

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[15] Attachment SG-4, "Life-cycle" (tabulating the workbooks produced in response to CalAdv DR-002, Q1.b).
[16] Response to UCAN DR-02, Q12.c.
[17] Response to UCAN DR-02, Q15.a; see also Q12.b (SDG&E declined to quantify the 2032–2045 recurring charges as "outside the scope of this proceeding").
[18] Response to UCAN DR-02, Q11.b (factor table, "Original Filing" and "Revised Allocations"; the filed allocation is "illustrative") and Q11.c (amounts derived from the factors "may not replicate the revenue requirement model"). Neither factor set produces the $420.4 million gas revenue requirement the Commission is asked to adopt (see Section VI).
[19] Attachment SG-3, "Allocation."
[20] Ex. SDG&E-06 at CWB-7, Table 6-4.
[21] Response to UCAN DR-02, Q11.a.
[22] Response to UCAN DR-02, Q11.c and Q11.d.

1. Authorize the Foundational Technology platform and an initial deployment phase ("Phase 1") through the end of 2029, consisting of the replacement of SM 1.0 devices as they fail and the proactive replacement of the electric meters in the capacitor-defect cohort, at defined authorized amounts, and condition any authorization of mass deployment ("Phase 2") on a Commission review of Phase 1 results against metrics drawn from SDG&E's own procurement documents; and decide the NextGen capabilities and their recurring charges at that checkpoint rather than in this decision (see Section IV).

2. Replace the proposed two-way AMIBA with a one-way balancing account with authorized amounts defined by category and year; require an application, not an advice letter, for recovery of costs above the authorized amount; apply a shareholder sharing band above the cap to any Phase 2 authorization; amortize the balance accumulated in the memorandum account from January 1, 2024 to the date of the decision over three years rather than a single-year catch-up; require an annual report; and exclude recurring charges beyond the period the authorized amounts cover, which for the Application as filed ends in 2031, from any balancing-account carry-over so that they are reviewed in a general rate case (see Section V).

3. Treat recurring software, connectivity and subscription charges as operating expense rather than as five-year capital assets; require SDG&E to disclose the full life-cycle of those charges in any cost comparison; and use a twenty-year depreciation life for meters and modules, consistent with the manufacturer's design life and with the benefit life SDG&E uses in its cost-benefit analysis (see Section V).

4. Direct SDG&E to serve corrected revenue-requirement tables reflecting the allocation factors it disclosed; adopt a benefit-based allocation for the shared platform; assign NextGen costs entirely to electric ratepayers; and hold gas-only customers harmless from NextGen-related charges (see Section VI).

5. Condition any authorization on fifteen-minute, two-channel interval data for all electric customers as a base feature, an open local data interface for customer-chosen devices at no opt-in charge, measurable data-service levels adopted from the vendor's own commitments with annual reporting, and a gas data plan (see Section VII).

6. Convene a technology advisory panel, as the Commission did for SM 1.0 in D.07-04-043, that includes the Community Choice Aggregators (CCAs), the California Independent System Operator and the California Energy Commission, to review the checkpoint deliverables, including the NextGen roadmap and a data plan for the CCAs, whose present data access does not meet the statute (see Section VII).

Attachment SG-5 sets out proposed ordering-paragraph language for each recommendation.

Q. Please describe the models accompanying your testimony.

A. Three workbooks accompany this testimony. Each is built from SDG&E's confidential workpapers and discovery responses; every input is labeled with its source, and the calculations are live formulas that respond to the levers on each workbook's Inputs sheet.

- **Attachment SG-2, Deployment Scenario Present-Value Model.** SG-2 builds, for each deployment scenario, the annual volumes of SM 2.0 devices installed, the resulting device, program, platform and recurring costs at SDG&E's unit prices and escalation rates, the SM 1.0 continuation costs where SM 1.0 operates beyond 2031, and the revenue requirement through 2071 using SDG&E's authorized rate of return, capital structure, tax rates and loaders. It discounts the revenue requirement to 2026 at SDG&E's authorized rate of return,[23] the rate SDG&E's own cost-benefit analysis uses.[24] Calibrated to SDG&E's schedule and accounting, the model reproduces SDG&E's $825.0 million loaded cost within 0.4 percent and its $1,325.5 million revenue requirement within 0.5 percent. Four scenarios are compared on a common decision date, and each is run on three failure paths: SDG&E's forecast, the trend of SDG&E's 2024–2026 actuals, and a mid-point.

- **Attachment SG-3, Gas/Electric Allocation Model.** SG-3 applies three factor sets to each of SDG&E's cost lines: the factors SDG&E says it used in the Application, the "Revised Allocations" SDG&E supplied in discovery, and a benefit-based set. It converts loaded costs to revenue requirement by asset class using multipliers derived from SG-2 and reconciles to SDG&E's Table 6-4 total within 0.1 percent.
- **Attachment SG-4, Recurring SaaS and Connectivity Charges.** SG-4 tabulates, by year through 2044, the recurring charges that SDG&E's two vendor-cost workbooks compute, compares them with the amounts in the Application, and quantifies the revenue-requirement effect of capitalizing five-year prepayments rather than expensing them.

[23] Ex. SDG&E-06 at CWB-6, lines 9–10 (7.45 percent).
[24] Ex. SDG&E-07-2E at NR/DT/MW-27, lines 9–14.

Q. Why was it necessary to construct a model to assess the present value of the revenue requirement under alternative deployment schedules?

A. Because SDG&E declined to produce the model in which its own revenue requirement was computed, and declined to produce any revenue requirement or present-value comparison for a schedule other than the one it filed. Its only comparison of deployment schedules is the nominal, undiscounted delay comparison in Table 3-10, which contains no revenue requirement and no present value.[25] Asked to produce, in native format with formulas intact, the model in which the jurisdictional allocation and revenue requirement in Table 6-4 were computed, SDG&E answered that it "does not provide its revenue requirement model to external parties due to the model's complexity and its dependence on external files located within SDG&E's internal network," offering instead "additional explanation regarding the calculation approach."[26] SDG&E also describes the revenue requirement it filed as "illustrative," reflecting "assumptions used solely for forecasting purposes."[27] A model that cannot be examined cannot be run on a different schedule, and a revenue requirement that its sponsor calls illustrative cannot be tested for what it would be under a different one.

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[25]Ex. SDG&E-03 at DT/BB-36 to DT/BB-38 and Table 3-10; Ch. 3 Workpaper 3, tab "WP 3.10.1" (no annual cash flows and no discounting). Asked to confirm that no present-value or revenue-requirement comparison of the base case against the delay scenarios exists, SDG&E answered by cross-reference to its objection to another question. Response to UCAN DR-02, Q2.b (referring to the response to Q1).

[26]Response to UCAN DR-02, Q11.a. The revenue-requirement workpaper served with the Application contains no calculation: every annual value in the jurisdictional tabs for 2024 through 2071 is a typed number, with no allocation factor and no link to any cost category. Ch. 6 Workpaper 1, tabs "WP6.4.2 (Rev Req - FERC)," "WP6.4.3 (Rev Req - CPUC Elec)" and "WP6.4.4 (Rev Req - CPUC Gas)," columns C through AX.

[27]Ex. SDG&E-06 at CWB-7, lines 9–10 ("The above revenue requirement is illustrative"); Response to UCAN DR-02, Q11.b ("The revenue requirement forecast presented in SDG&E's Application is illustrative and reflects assumptions used solely for forecasting purposes").

Nor did SDG&E supply the alternative forecasts when parties asked for them:

- Asked whether it had evaluated how costs would change under "a smaller pilot, slower deployment, or phased deployment schedule," SDG&E answered that it "did not assess alternative scenarios such as a smaller pilot, slower or phased deployment."[28]
- Asked for the revenue requirement of an authorization limited to the Foundational Technology platform and an initial deployment tranche, SDG&E answered that it "has not prepared, and does not maintain in the ordinary course of business, the revenue requirement, cost allocations, or operational assumptions necessary to evaluate" that construct.[29]
- Asked for revised versions of Tables 3-1 and 6-1 on the assumption that first installations occur in 2028 rather than 2027, SDG&E objected to any obligation "to generate or create records that do not exist" and stated that it "has not prepared revised versions" of either table.[30]
- Asked for a re-run of its failure forecast without the capacitor-defect cohort, SDG&E objected that the request "calls for SDG&E to create documents not already in SDG&E's possession" and declined, an objection it has made to requests for underlying calculations from other parties as well.[31]

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[28]Response to CalAdv DR-005, Q22.b.
[29]Response to SBUA/TURN DR-001, Q3.a (Sept. 21, 2026).
[30]Response to UCAN DR-02, Q7.b.
[31]Response to SBUA DR-003, Q1(c); see also Responses to CalAdv DR-006, Q23.b, Q25 and Q38–Q41 (same objection to requests for the calculations behind cost-benefit inputs).

The Commission cannot weigh a phased deployment against the Application on a record in which the only revenue requirement is the applicant's, the model behind it is withheld, and the applicant declines to compute any other. Attachment SG-2 was built to supply what the record otherwise lacks: a revenue-requirement model, served in native form with every formula intact, that reproduces SDG&E's filed result from SDG&E's own inputs and can then be run on any schedule.[32]

Q. Have you validated your model's results against SDG&E's Application?

A. Yes. Before running any alternative, I ran the model on the Application as filed: SDG&E's 2027 through 2030 installation volumes, its unit costs, contingency and overheads, fifteen-year lives, the five-year prepayments capitalized as SDG&E proposes, no recurring charges after 2031, and the financing and tax parameters SDG&E uses.[33]

Table 1 compares the result with the figures in Ex. SDG&E-06. The loaded program cost agrees with SDG&E's $825.0 million within 0.3 percent, the revenue requirement over 2024 through 2071 agrees with Table 6-4's $1,325.5 million within 0.4 percent, and 2031 depreciation agrees within 0.4 percent.[34]

Table 1. Model calibration to the Application as filed ($ million)

Item	Attachment SG-2 (Calib-SDGE)	SDG&E	Difference
Loaded program cost, 2024–2031	827.6	825.0	+0.3%
Revenue requirement, 2024–2071	1,331.2	1,325.5	+0.4%

[32] Attachment SG-2, "README" and "Inputs."

[33] Attachment SG-2, sheet "Calib-SDGE" (settings block, rows 5–16) and sheet "Reconciliation." The financing parameters are SDG&E's authorized capital structure and 2025 component costs (Ex. SDG&E-06 at CWB-6, lines 6–12 and n.10; 7.45 percent).

[34] Attachment SG-2, "Reconciliation," rows 3–6; Ex. SDG&E-06, Table 6-2 ($825.0 million) and Table 6-4 ($1,325.5 million; $839.8 million for 2032–2071); Ch. 6 Workpaper 1, tab "WP6.4.4" (2031 depreciation) (confidential).

Item	Attachment SG-2 (Calib-SDGE)	SDG&E	Difference
Revenue requirement, 2032–2071	849.9	839.8	+1.2%
Depreciation, 2031	73.4	73.1	+0.4%

Sources: Attachment SG-2, "Reconciliation," rows 3–6, and sheet "Calib-SDGE," row 103 and rows 108–119; Ex. SDG&E-06, Tables 6-2 and 6-4; Ch. 6 Workpaper 1, tab "WP6.4.4."

The annual profile also matches, with one timing difference that I have left in place deliberately. SDG&E books the five-year head-end and connectivity prepayments and the NextGen software bundle in 2027, the year the contracts are signed; the model accrues the same charges as endpoints enter service, so the model's 2027 and 2028 revenue requirements are lower than Table 6-4's ($25.0 and $60.5 million against $34.6 and $70.7 million) and its 2029 through 2031 values are within about 2 percent of SDG&E's ($108.2, $142.0 and $140.3 million against $110.5, $139.4 and $142.4 million).[35] The accrual treatment is the right one for comparing schedules, because it charges each scenario for the endpoints it actually has in service in each year, and it does not affect the totals. The remaining difference, about half a percent of the revenue requirement, is within the precision of SDG&E's own forecast, which SDG&E calls illustrative.

Two further checks confirm the calibration. The revenue requirement per loaded dollar that the model derives by asset class, 1.776 for fifteen-year meter-class plant, 2.042 for twenty-year plant and 1.231 for five-year software, is the multiplier set that Attachment SG-3 uses, and applying it to SDG&E's cost categories reproduces the $1,325.5 million total within

[35] Attachment SG-2, "Calib-SDGE," row 103 ("Total revenue requirement"), compared with Ex. SDG&E-06, Table 6-4, "Total" row. The model does not reproduce the negative amounts SDG&E shows for 2024 and 2026 (−$6.3 and −$10.4 million), which arise from SDG&E's accounting for pre-in-service spend and which, with 2025, net to −$11.9 million; the model carries $5.3 million for those three years. Excluding 2024–2026 the model is $12 million (0.9 percent) below Table 6-4; including them it is $6 million (0.4 percent) above.

0.1 percent.[36] And the Application scenario that the alternatives are measured against (Scenario A) is the calibration run shifted by one year for the later decision date, so that every difference reported in Table 3 is a difference in schedule and not in method.[37]

Q. Does your testimony rely on Protected Materials?

A. Yes. The unit prices, vendor pricing structures, procurement documents and cost workbooks I rely on were produced under the Nondisclosure Certificate between UCAN and SDG&E. In this confidential version those passages are highlighted in yellow; they are redacted in the public version, which is otherwise identical in text, numbering and pagination. The bidders in SDG&E's procurement are referred to as "Vendor 1" and "Vendor 2," and the vendor SDG&E selected as the "Selected Vendor," following the convention SDG&E uses in its public testimony. Every discovery response and produced document I cite is reproduced in Attachment SG-6 (public discovery responses, in full, and the cited pages of public documents produced with them) or Attachment SG-7 (the cited pages of documents SDG&E has designated as Protected Materials, served only on parties to the Nondisclosure Certificate); each is identified there by the data request and question number used in my footnotes, and workbooks produced in native form are listed in the index to each attachment and served natively. [Confidential Information Begins] …………………………………………………………………………………………… [Confidential Information Ends].

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[36] Attachment SG-2, "Reconciliation," multiplier table ("Multiplier (sum of years 1–20)"); Attachment SG-3, "Inputs," rows 8–11, and "Allocation," row 26 (total $1,324.6 million against $1,325.5 million).

[37] Attachment SG-2, "Inputs" (schedule-shift lever) and sheet "A"; Table 3 (Section IV.E).

Q. To what extent does your testimony rely on workpapers that SDG&E has withdrawn?

A. In four identified places, each labeled as such in the text or the footnote, and in each case the point either stands on a served source that SDG&E has not withdrawn or is a point about what the withdrawn material shows regarding SDG&E's own filed figures. On September 14, 2026, six days after UCAN served a data request regarding hidden sheets contained in workpaper files, SDG&E notified parties that four workpaper files served with the Application in December 2025 "were found to contain hidden tabs with incomplete internal draft material that was inadvertently included in the production," that the material "does not reflect SDG&E's finalized analysis, conclusions, or positions," and that it had replaced the files with versions that "remove the hidden tabs and contain no other changes."[38] The visible figures in the workpapers, and every figure in SDG&E's testimony, are therefore unchanged. What was removed were worksheets that had been saved in the hidden state:

- In Chapter 2 Workpaper 1, worksheets titled "Failure Reforecast" and labeled "Break and Replace 2.0," carrying an electric and gas failure forecast for 2025 through 2035 and a residual electric population.
- In Chapter 3 Workpaper 3, a worksheet titled "Updated IT Assumption," pricing an incumbent-hosted head-end for the delay scenarios, a worksheet titled "Dileep_Rough," containing the only device-cost calculation in that workbook, and a fifteen-year depreciation curve.

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[38]SDG&E notice to parties, "SDG&E Smart Meter Application (A.25-12-012) Replacement Workpapers" (Sept. 14, 2026), replacing Chapter 2 Workpaper 1 and Chapter 3 Workpapers 2, 3 and 4; Response to UCAN DR-02, Q1 (repeating the notice). UCAN DR-02 was served on September 8, 2026.

- In Chapter 3 Workpapers 2 and 4, two worksheets containing a combined vendor-services buildup.[39]

My testimony uses that material as follows:

- First, Table 2 reproduces the "Break and Replace 2.0" failure volumes beside the volumes SDG&E asked bidders to price, because the 2027 through 2032 volumes in the RFP are identical, year for year, to that forecast. The point of the table is the identity, and the identity rests on the RFP, which SDG&E issued to vendors in March 2025 and has not withdrawn; the hidden worksheet shows where the RFP volumes came from.
- Second, in addressing the "end-of-life" premise I note that the withdrawn forecast showed 360,422 SM 1.0 electric meters still communicating at the end of 2035; the same point is made from the forecast model SDG&E produced in discovery and has not withdrawn, which shows about 80 percent of the pre-2020 fleet operating at the end of 2028 and about 264,000 meters operating at the end of 2035, and my conclusion rests on the produced model.
- Third, Attachment SG-2 carries, for every year after 2031 in which SM 1.0 devices remain in service under Scenarios B and C2, the cost of an incumbent-hosted SM 1.0 head-end at the figures in the "Updated IT Assumption" worksheet, about $3.6

[39] Chapter 2 Workpaper 1, tab "Failure Reforecast" (cells C20–N32); Chapter 3 Workpaper 3, tabs "Updated IT Assumption," "Dileep_Rough" and "Depreciation"; Chapter 3 Workpapers 2 and 4, tabs "2.WP-1 (IT Total)" and "2.1.5 WP-5 (Vendor Services (2)", each as served December 18, 2025 (present in the public and the confidential versions of the Chapter 3 workpapers). The worksheet identifiers in the served files show that further worksheets were removed before service.

million a year plus $3.1 million of one-time migration cost.[40] That is a cost charged against UCAN's own scenarios, not against SDG&E's; using SDG&E's own figure for it is the conservative choice, and SDG&E has offered no other figure for it.

- Fourth, in Section IV.D, I observe that the "incremental SM 1.0 direct costs" in Table 3-10 are typed values with no supporting calculation, and that the one calculation in the same workbook, on the "Dileep_Rough" worksheet, produces different totals. That observation is about the absence of support for a figure SDG&E has not withdrawn.

I consider the reliance defensible for four reasons. The workpapers are SDG&E's own documents, served with its Application under its witnesses' names nine months before they were withdrawn, and served again in discovery; a party that serves an analysis in support of its request cannot, by relabeling part of it as "draft" after a question is asked, put that part beyond examination. SDG&E has not said that any number in the withdrawn worksheets is wrong, who prepared them, when, or for what purpose; it has said only that they are incomplete and internal. Key elements of the withdrawn material are corroborated by documents SDG&E has not withdrawn: the "Break and Replace 2.0" volumes reappear in the RFP's Appendix AB, and the hosting figures in "Updated IT Assumption," carried through the years of each delay case and escalated as the worksheet directs, account on their face for the $26.1 million and $30.9 million "Foundational Technology" increments

[40] Attachment SG-2 [Confidential Information Begins] ………………………….……………………… …..[Confidential Information Ends].

that remain in Table 3-10 and in the visible summary of the same workbook.[41] And in each place the testimony says what it is relying on, so that the Commission can weigh it accordingly.

SDG&E has declined to explain the material. UCAN DR-02, Question 1, asked SDG&E to describe the "Break and Replace 2.0" scenario, when and why it was prepared and by whom, and to produce the native workbook that generated it; Question 2 asked SDG&E to produce the calculation behind the four typed values in Table 3-10, to confirm that no present-value comparison of the delay scenarios exists, and to confirm that the "Foundational Technology" increment consists of the hosting costs in the "Updated IT Assumption" worksheet. SDG&E objected to Question 1 as seeking information "neither relevant to the subject matter … nor … likely reasonably calculated to lead to the discovery of admissible evidence because it references preliminary draft work product rather than a final position," and as calling for speculation, and answered by repeating its September 14 notice; it answered Question 2 by cross-reference to that response.[42]

UCAN has served a further request asking, for each hidden or removed worksheet, who prepared it, when and for what purpose; whether any value in it feeds a figure in SDG&E's testimony; for the production of each removed worksheet; for an explanation of why the withdrawn electric forecast differs from the visible one and which of the two was used for Figure 2-3, the like-for-like replacement forecast, Workpaper 3 and the "projection"

[41]Chapter 3 Workpaper 3, tab "WP 3.10.1," cells F18 and I18 (not withdrawn); compare tab "Updated IT Assumption," rows 2–5 and the note "For Option 1 - costs above extend through 2035 (at 25% for a half year)" (the tab is present in the public workpaper as served). UCAN asked SDG&E to confirm the correspondence (UCAN DR-02, Q2.c); SDG&E did not answer.

[42]Response to UCAN DR-02, Q1 and Q2.

against which SDG&E reported 2025 failures as "approximately 19% below"; and whether the "Break and Replace 2.0" volumes were provided to any consultant or vendor.[43] If SDG&E answers, I will update Attachment SG-2 and this testimony on receipt; if it maintains that the worksheets are irrelevant draft material, the Commission will have before it SDG&E's served figures, the worksheets that produced them, and SDG&E's refusal to reconcile the two.

Q. How is the remainder of your testimony organized?

A. Section III states the standard the Application must meet. Section IV addresses deployment strategy and the phased authorization I recommend. Section V addresses cost recovery design, recurring charges and depreciation lives. Section VI addresses the gas/electric allocation. Section VII addresses recommended functional conditions of approval, the NextGen capabilities and proposed technology advisory panel. Section VIII summarizes my recommendations.

Seven attachments accompany this testimony:

1. Attachment SG-1 sets out my qualifications and experience.
2. Attachment SG-2 is the deployment scenario model: a revenue-requirement and present-value model, served in native form with every formula intact, that reproduces SDG&E's filed result from SDG&E's own inputs and then runs the Application schedule and the alternatives in Section IV on a common assumed decision date.

[43] UCAN-SDG&E-DR-03, Q6 and Q7 (served September 25, 2026; responses requested by October 9, 2026).

3. Attachment SG-3 is the gas/electric allocation model that applies SDG&E's own disclosed factors and the benefit-based factors I recommend in Section VI to SDG&E's cost categories.
4. Attachment SG-4 tabulates the recurring software, connectivity and subscription charges over the life of the platform, on SDG&E's rates, and shows the effect of capitalizing rather than expensing them.
5. Attachment SG-5 contains proposed ordering paragraphs for each recommendation in Section VIII.
6. Attachment SG-6 reproduces, in full, each SDG&E discovery response cited in this testimony, with the cited pages of any public document produced with it, so that the responses are in the record.
7. Attachment SG-7 reproduces the cited pages of the documents SDG&E has designated as Protected Materials.

III. <u>THE STANDARD THE APPLICATION MUST MEET</u>

Q. What must SDG&E show to obtain the authorization it requests?

D.24-12-074 told SDG&E what a renewed request had to contain. The Commission found that SDG&E had "not provided a comprehensive cost-benefit analysis comparing various replacement strategies, including battery replacement,"[44] that "a comprehensive cost-benefit analysis comparing various replacement strategies is essential to ensure that ratepayers are not unduly burdened with unnecessary costs,"[45] and that "a more

[44] D.24-12-074, Finding of Fact 317 at 1010.
[45] D.24-12-074 at 674.

comprehensive evaluation of SDG&E's decision to procure and implement a Smart Meter 2.0 system is necessary. This analysis should assess SDG&E's proposal for long-term viability, the potential for stranded assets, and whether a competitive procurement process would have yielded a better outcome."[46] It also required a transition plan for maintaining the current system during replacement, the separate cost of gas and electric replacement, and an explanation of the sequencing.[47]

Q. As a threshold matter, did SDG&E oversee a robust competitive solicitation?

A. No. SDG&E invited five vendors to its March 2025 request for proposals and received two proposals; the other three invited vendors, including the incumbent, declined to bid.[48] The RFP was released on March 25, 2025 with proposals initially due April 21, 2025; the due date was extended to May 12, 2025, so that the bidders had seven weeks in all.[49] Two proposals do not test a market, and the circumstances of these two make the point sharper. [Confidential Information Begins] …………………………………………………………… ……………………………………………………………………………………………… ……………………………………………………………………………………………… ……………………………………………………………………………………………… ….................................[Confidential Information Ends].[50] SDG&E had run a solicitation

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[46] D.24-12-074 at 675; see also Finding of Fact 316 at 1010 and Ordering Paragraph 51 at 1100.
[47] Id. at 675.
[48] Ex. SDG&E-03 at DT/BB-28, lines 16–19 ("soliciting bids from the leading five smart meter vendors (including SDG&E's incumbent vendor) … Two vendors responded to the RFP … SDG&E's incumbent vendor did not offer a bid"); Response to CalAdv DR-002, Q5.j.i–ii and Q5.j.iv ("three vendors declined to bid").
[49] Response to CalAdv DR-002, Q5.b, RFP package, "Appendix A_Master RFP Document_Revised 040125," Section G ("RFP Schedule"): release March 25, 2025; RFP due date "Monday, 5/12/2025 5pm," superseding "4/21/2025 5pm."
[50] Response to CalAdv DR-002, Q5.b (confidential).

in 2021 in which six vendors bid, and it describes the 2025 RFP as producing "similar pricing to the RFP conducted in 2021"; the Commission's direction in D.24-12-074 was that any renewed request assess "whether a competitive procurement process would have yielded a better outcome."[51]

The three vendors that declined gave reasons that go to the design and conduct of the solicitation rather than to any lack of interest in the work. The incumbent declined on the due date, stating that its response to SDG&E's parallel request for quotation on extending SM 1.0 already described "how Itron would support the current system and enhance it to equip SDG&E with AMI 2.0 capabilities," and that it would "defer to the content in our RFQ submittal."[52] As I discuss above, SDG&E then excluded the incumbent's RFQ response from its formal evaluation, so the one vendor with an installed base and a working network in the territory was never compared with the two proposals. [Confidential Information Begins] …..………………………………………………………………… ……………………………………………………………………………………………… ……………………………………………………………………………………………… ……………………………………………………………… [Confidential Information Ends].[53][Confidential Information Begins]……………………………………………… ………………………………………………………………………………………………

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[51]Response to CalAdv DR-002, Q5.j.iv ("the 2025 RFP produced similar pricing to the RFP conducted in 2021, in which six vendors bid, when evaluated through standard escalation methods"); D.24-12-074 at 675 (directing that any renewed request assess "whether a competitive procurement process would have yielded a better outcome").

[52]Response to CalAdv DR-002, Q5.c and Q5.j.ii, attachment "5.c SDG&E AMI 2.0 RFP – Itron Letter 2025 May 12_Decline to Bid" (confidential), at 1. SDG&E states that it "did not consider, evaluate, score, or compare the incumbent vendor's RFQ response as part of its formal evaluation of AMI 2.0 alternatives." Response to UCAN DR-02, Q10.a.

[53]Response to CalAdv DR-002, Q5.j.i–ii, attachment "5.j.

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.... [Confidential Information Ends].[54]

SDG&E's answer to the thin field is that it evaluated the two proposals against the 2021 pricing and an Ernst & Young benchmark, and that a single vendor is preferable to two because two head-ends would be duplicative.[55] Neither point cures the defect. A benchmark against a four-year-old solicitation confirms that prices have not moved; it does not show that the market was tested in 2025. And a single-vendor preference explains why SDG&E did not split the award, not why the RFP was written so that a vendor offering a second-source electric meter, or a separate gas network, could not respond. [Confidential Information Begins]…………………………………………………………...………… .... [Confidential Information Ends].[56] the result was a solicitation in which the vendor that had already negotiated the contract terms bid against one other vendor, the incumbent was excluded from the comparison, and the two vendors that might have supplied competitive tension on price and on the gas side said the document was not written in a way they could answer.

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[54]Response to CalAdv DR-002, Q5.j.i–ii, attachment "5.j[Confidential Information Begins] [Confidential Information Ends]. (confidential), at 1–2.
[55]Response to CalAdv DR-002, Q5.j.iv–vi.
[56]Response to CalAdv DR-002, Q5.b, [Confidential Information Begins] ……………………………………… ……………………………………………………………………………..………...…………………..…… … ....[Confidential Information Ends]. (all confidential)

That is the record on which the Commission is asked to find that the $825 million price is a market price.

IV. DEPLOYMENT STRATEGY

A. What the Application proposes and what it rests on

Q. Please describe SDG&E's proposed deployment.

A. SDG&E proposes to replace 1,634,498 electric meters and 952,761 gas modules over four years, with 132,363 electric meters and 30,904 gas modules in the first year, 388,681 and 224,038 in the second, 653,596 and 399,968 in the third, and 459,858 and 297,851 in the fourth,[57] and to replace the SM 1.0 head-end, hardware security module, RFLAN network and data mart with a cloud-hosted head-end and cellular network supplied by the Selected Vendor, retaining the meter data management and other back-office systems.[58]

Note that while the Application assumed a final decision in December 2026 and deployment in 2027–2030;[59] the Scoping Memo's schedule places a proposed decision in the third quarter of 2027,[60] so the earliest practical start of deployment is 2028 and the Application's own dates are no longer achievable; SDG&E states that it "is evaluating its planning assumptions schedule and has yet to finalize revised assumptions regarding the timing of a final Commission decision or a revised deployment schedule."[61] The

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[57] Ch. 3 Workpaper 1, notes A29–A30; Ex. SDG&E-04, Figure 4-3.

[58] Ex. SDG&E-05 at BMB-2, lines 6–18 (the "Persistent SM Systems" that are not being replaced); Response to CalAdv DR-003, Q13.d (systems to be retired: the SM 1.0 head-end, the Certicom hardware security module and the Smart Meter Data Mart).

[59] Application at 11 (proposed schedule: "Commission Final Decision December 2026") and Attachment A at 1 (requesting "a decision by the end of 2026"); Ex. SDG&E-01 at DG-12, lines 2–4.

[60] Assigned Commissioner's Scoping Memo and Ruling (Aug. 18, 2026) at 7 (schedule; "Commission proposed decision — Q3 2027").

[61] Response to UCAN DR-02, Q7.a.

comparisons in this testimony therefore place every scenario, including SDG&E's, on a common decision date of the fourth quarter of 2027 with first installations in 2028.

Q. On what factual premises does the four-year schedule rest?

A. SDG&E's proposed deployment schedule rests principally on four premises. First, that "end-of-life for SM 1.0 electric meters and gas modules will occur between 2026-2028."[62] Second, the failure forecast in Chapter 2.[63] Third, the 2028 expiration of the product-availability and support commitments in the 2008 agreement with the incumbent vendor, Itron.[64] Fourth, SDG&E's characterization of Itron's 2025 response to a request for quotation as having "committed to working with SDG&E but [not guaranteed] sufficient supply of SM 1.0 devices between 2028-2035."[65]

Q. Is SDG&E's deployment schedule justified?

No. Each premise is weaker than the testimony presents it, and none supports the conclusion that the whole fleet must be replaced within four years of a decision; the operational drivers SDG&E also cites scale with the forecast or the head-end transition (see Sections IV.C and IV.F).[66]

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[62] Ex. SDG&E-01 at DG-4, lines 3–5; Ex. SDG&E-02 at SB-6, line 14, and SB-7, Figure 2-2.
[63] Ex. SDG&E-02 at SB-8, Figure 2-3, and SB-8 to SB-10 (forecast methodology); Ch. 2 Workpaper 1, tab "WP 2.3.1."
[64] Ex. SDG&E-02 at SB-11, lines 3–4 ("SDG&E's Master Services Agreement (MSA) with the incumbent vendor expires in 2028."); Response to Mission:data DR-001, Q4.a ("The MSA between SDG&E and Itron will expire July 2028."); Response to CalAdv DR-002, Q5.d (the vendor's maintenance-and-support, pricing and product-availability obligations under the MSA expire in 2028); see also Ex. SDG&E-02 at SB-20, lines 1–4 (head-end and hardware-security-module support under the MSA "will expire in 2028").
[65] Ex. SDG&E-01 at DG-10, lines 12–15; Ex. SDG&E-03 at DT/BB-36, lines 3–8 (public version pagination is used for Ex. SDG&E-03 throughout).
[66] Ex. SDG&E-02 at SB-15, lines 5–9 (field workforce capacity of about 60,000 replacements a year); SB-18, lines 7–8 (RFLAN mesh degradation); SB-18, line 19 to SB-19, line 3 (field area router warranty and 4G dependence); SB-19, lines 4–18 (gas-module Zigbee dependence); SB-20, lines 11–13 (cybersecurity).

B. SDG&E forecasts most SM 1.0 meters as active post-2028 & can extend vendor support services

Q. Please address SDG&E's "end-of-life" premise.

A. SDG&E arrived at 2026–2028 "end of life" window by adding the 17-year project life assumed in D.07-04-043 to the 2009–2011 years in which most SM 1.0 devices were installed.[67] SDG&E acknowledges that the 17-year figure is a system-level assumption "not specific to electric meters" and that it "does not currently have workpapers and measurements supporting a 17-year lifespan";[68] and the record shows that the manufacturer designs the meters for twenty years,[69] a fact the Commission relied on in D.24-12-074 when it found that modules SDG&E proposed to replace at thirteen to sixteen years of age had "a reasonable useful remaining life of five to six years."[70]

SDG&E also acknowledges that the vendor's accelerated life testing gave it "reasonable assurance" of the 20-year design life, and its contrary system-level assessment rests on the failure forecast,[71] which is itself inconsistent with assuming fleet-wide end-of-life in 2026–2028: it has about 80 percent of the pre-2020 electric fleet it models still communicating at the end of 2028,[72] and the same forecast has about 264,000 of those meters still operating

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[67] Ex. SDG&E-02 at SB-6, lines 11–14 ("Applying this 17-year timeline to SDG&E's initial SM 1.0 deployment offers a clear view of when installed SM 1.0 electric meters and gas modules are expected to reach end-of-life. SDG&E's SM 1.0 devices were mostly deployed during the 2009-2011 period, which means that end-of-life will occur between 2026-2028"); see also Ex. SDG&E-01 at DG-4, lines 3–5.
[68] Response to CalAdv DR-002, Q4.a.
[69] D.24-12-074 at 673.
[70] D.24-12-074 at 673; Finding of Fact 316 at 1010.
[71] Response to CalAdv DR-002, Q4.b (the testing "provided SDG&E with reasonable assurance that the devices were designed and constructed to meet the expected 20-year lifespan under normal operating conditions"; SDG&E's system-level assessment "using observed and forecasted failure performance" "yielded a lifespan less than the 20-years").
[72] Response to CalAdv DR-004, Q1.b, workbook "CalAdv-DR-004-SDGE Electric Failure Forecast Details.xlsx," tab "Electric CAGR Details" (summing the district and cohort rows: a modeled pre-2020 fleet of 1,317,906 meters

at the end of 2035;[73] the reforecast tab SDG&E served and later withdrew as draft showed 360,422 still communicating in 2035.[74]

In discovery, SDG&E has clarified that its statement that “end of life will occur between 2026 and 2028 refers to the Smart Meter 1.0 system as an integrated AMI platform, it is not a representation or guarantee regarding operation of individual electric meters or gas modules during that time.”[75] The system-level “end of life” is a technology-generation judgment, not a finding that the devices stop working;[76] what does expire in 2028 is contractual. The 2008 agreement confirms this: [Confidential Information Begins]………

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.... [Confidential Information Ends].[77]

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at the start of 2025 and 1,275,337 at the end of 2025; expected failures of 56,991, 73,220 and 91,715 in 2026, 2027 and 2028; and 1,053,411 expected operating units at the start of 2029, which is 80 percent of the start-of-2025 fleet and 83 percent of the end-of-2025 fleet). The tab excludes meters installed in 2020 or later, which SDG&E states “are not expected to fail in significant quantities by 2035.” Id., tab “Electric CAGR Glossary.”

73 Response to CalAdv DR-004, Q1.b, workbook “CalAdv-DR-004-SDGE Electric Failure Forecast Details.xlsx,” tab “Electric CAGR Details” (340,530 expected operating units at the start of 2035 less 76,126 expected failures in 2035, or 264,404; the tab excludes meters installed in 2020 or later).

74 Ch. 2 Workpaper 1, tab “Failure Reforecast,” as served December 18, 2025. SDG&E removed the worksheet from the workpaper on September 14, 2026 as “internal draft material,” Response to UCAN DR-02, Q1.

75 Response to CalAdv DR-002, Q4.g.

76 Response to CalAdv DR-002, Q4.a (the system-level life “recognizes that AMI technology evolves over time and that large-scale infrastructure deployments are periodically replaced by newer generations”); Ex. SDG&E-02 at SB-10, lines 14–15 (cumulative failures forecast to reach “well over half the population by year’s end 2031”).

77 Response to CalAdv DR-002, Q1.b and Q4.g, attachment “Q4.g – PAO-SDGE-179_ATTACH_Q1b” (Agreement No. 5660012744) (confidential): [Confidential Information Begins]…………………………………...……………
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Q. Please address the vendor-support premise.

A. [Confidential Information Begins]…………[Confidential Information Ends][78] and SDG&E clarified in discovery that it "has not received formal communications from its current vendor for End of Manufacture or Last Time Buy declaration,"[79] is "not aware of any communication in which Itron established a definitive End-of-Support date" for the OpenWay Collection Engine head-end,[80] [Confidential Information Begins]……………… ……[Confidential Information Ends][81]

[Confidential Information Begins]……………………………………………..…………… ………………………….…………………………………………………………………… …...........................[Confidential Information Ends][82] [Confidential Information Begins] …..[Confidential Information Ends][83] [Confidential Information Begins]… .... [Confidential Information Ends] [84] but that is a reason to plan and price the head-end transition, as

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Ends]. SDG&E describes the same terms in Response to CalAdv DR-002, Q5.d, and Response to UCAN DR-02, Q9.b ("Schedule B §2.1(b) of the 2008 agreement").

[78] Response to CalAdv DR-002, Q5.d [Confidential Information Begins]…………………………..…………… … .... [Confidential Information Ends].

[79] Response to CalAdv DR-003, Q14.b.

[80] Response to UCAN DR-02, Q10.c.

[81] Response to UCAN DR-02, Q10.d (confidential).

[82] Response to CalAdv DR-003, Q30.b, attachment "SDGE – RFQ Follow Up Questions_Itron Final_06102025" (confidential), at 2 (Scenario 1) [Confidential Information Begins]………………………………………………… ……………………………………………………...………………………………………………………… …………………………..……………………………..……………………………………………………… …….[Confidential Information Ends] quoted in Response to CalAdv DR-002, Q5.i; Response to CalAdv DR-003, Q14.c (SDG&E "has not received contractual assurances that would prevent a vendor from issuing a formal End of Manufacture or Last Time Buy declaration"); Response to CalAdv DR-002, Q5.d (Itron "would cease providing any such software and related maintenance & support service in 2035").

[83] Response to UCAN DR-02, Q10.d and Q10.e (confidential) [Confidential Information Begins]…………… ………………………….…………………………………………..…………………………………………… … ....[Confidential Information Ends]

[84] Response to UCAN DR-02, Q9.e [Confidential Information Begins]………………………………………..…… ……………………………………………………………………………………………………...……………

Attachment SG-2 does (see Section IV.E), not a reason to replace 1.6 million meters by 2031. Relevant here is that [Confidential Information Begins]………………………… ………………………………………………………………………..………..………… ………………………..……………………………………………………………………… …………………………………………………………………………………………… …………………………………………………………………………………………… …………………………………………………………………………………………… …..………….[Confidential Information End][85] [Confidential Information Begins]… …………………………………………………………………………………………… ………………………..……………………………………………………………………… ………………………….[Confidential Information Ends][86] [Confidential Information Begins]…………………………………………………………………..……..…………… ………………………..……………………………………………………………………… ……………[Confidential Information Ends][87][Confidential Information Begins]………

… .... [Confidential Information Ends]; Response to CalAdv DR-002, Q10.d.

[85] Response to CalAdv DR-003, Q30.b, attachment "SDGE AMI 1.0 RFQ Proposal – Itron 2025 May 05" (confidential), Executive Summary at 1–3 and Solution Summary at 4, 6, 7, 13 and 18.

[86] Response to CalAdv DR-003, Q30.b, attachment "SDGE AMI 1.0 RFQ Proposal – Itron 2025 May 05" (confidential), Executive Summary at 1 [Confidential Information Begins]……………………… ………………………………………..……………………………………………………………………… … .... [Confidential Information Ends] and Solution Summary at 4; attachment "SDGE – RFQ Follow Up Questions_Itron Final_06102025" (confidential), at 2 [Confidential Information Begins] ……………………………………………………………..…………………………………………………… … .... [Confidential Information Ends]; Response to CalAdv DR-002, Q5.i, n.8 [Confidential Information Begins]……………… ……………………………………………..…………………………………………………………………… … .... [Confidential Information Ends]; see also Response to UCAN DR-02, Q10.b.

[87] Response to CalAdv DR-003, Q30.b, attachment "SDGE – RFQ Follow Up Questions_Itron Final_06102025" (confidential), at 2 and Scenario 1 pricing table.

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C. SDG&E's failure forecast is unvalidated and is diverging from (lower) actuals

Q. How was the electric failure forecast constructed?

A. For each of twelve district-by-cohort groups, SDG&E computed the compound annual growth rate of the annual failure rate from 2021 to 2025[90] and applied that growth rate to the failure rate in every future year, with no ceiling; the only bound is that failures cannot exceed the remaining population.[91] The growth rates range from 25 to 61 percent per year. The applied annual failure rate passes 100 percent for every capacitor-defect cohort by

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[88] Response to CalAdv DR-003, Q30.c.

[89] Ch. 3 Workpaper 3, tab "Updated IT Assumption," as served December 18, 2025 (removed September 14, 2026 as "internal draft material," Response to UCAN DR-02, Q1) [Confidential Information Begins]…………………… ……………………..……………………………………………………………………….………… ….. [Confidential Information Ends] Ch. 3 Workpaper 3, tab "WP 3.10.1," line 3 [Confidential Information Begins]........................ [Confidential Information Ends].

[90] Response to CalAdv DR-002, Q4.e.

[91] Response to CalAdv DR-004, Q1.b (workbook "CalAdv-DR-004-SDGE Electric Failure Forecast Details.xlsx," formulas).

2032–2034 and reaches 675 percent for one district in 2035; the 2031 peak in Figure 2-3 is produced by population exhaustion, not by any failure curve.[92]

SDG&E's testimony calls its 2024 GRC electric methodology "a highly accurate predictor,"[93] but it has since stated that a comparison of actual and projected failures "is only available for 2025,"[94] a year the current model missed. Asked to describe any back-testing, validation, sensitivity analysis or confidence ranges it prepared or relied on, SDG&E identified none, stating only that such analyses "may be a part of" its annual update process,[95] and for the gas model it confirms that it "has not performed a formal back-test."[96] The 2025 base year in the electric model is 42,569 failures, a November 2025 figure that includes a projected fourth quarter,[97] and SDG&E's reported 2025 actuals are 37,370 to 38,750,[98] so every growth rate is computed from a base 10 to 14 percent above what occurred; SDG&E's separate "approximately 19% below projection" refers to an unidentified projection.[99]

Q. How was the gas failure forecast constructed?

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[92] Response to CalAdv DR-004, Q1.a–b, workbook "CalAdv-DR-004-SDGE Electric Failure Forecast Details.xlsx," tab "Electric CAGR Details," column "CAGR Annual Failure %" (UCAN arithmetic); the growth rates are in column "CAGR."

[93] Ex. SDG&E-02 at SB-7, lines 9–14 ("proved to be a highly accurate predictor of lifecycle performance"), and SB-8, Figure 2-4; see also SB-8, lines 4–10 (the refined forecast "offers a high degree of accuracy"); Response to CalAdv DR-005, Q26.b (the gas methodology "provides a reliable, data-driven basis for projecting failures"); Response to CalAdv DR-004, Q1.f ("SDG&E updates its forecast annually to reflect actual data and trends.").

[94] Response to SBUA DR-003, Q1(e) (SDG&E "does not have prior testimony-level projections for 2015–2024 against which actual failures can be compared").

[95] Response to CalAdv DR-004, Q1.f.

[96] Response to UCAN DR-02, Q5.c.

[97] CalAdv DR-004 workbook, tab "Electric CAGR Details," 2025 "In-Year Failures" column (sum of the twelve district/cohort rows); tab "Electric CAGR Glossary" ("The subsequent tab contains details of the SDGE electric meter failure forecast conducted in November 2025"); Ex. SDG&E-02 at SB-9 n.12 ("SDG&E has experienced over 30,000 failures through September 2025. The total number of failures for 2025 is likely to be materially higher").

[98] Response to UCAN DR-02, Q4.i (37,370); Response to SDCP/CEA DR-001, Q1.b (38,201); Response to SBUA DR-003, Q8(a) (38,750).

[99] Response to SBUA DR-003, Q1(e).

A. In SDG&E's model, each module's future battery voltage is projected as a straight line whose slope is 0.4 times the single worst month-to-month drop observed over six monthly intervals (seven readings), floored at a mandatory decline of 0.002 volts per month, plus an unconditional aging term after month 20; a module "fails" in the first month the line crosses a threshold.[100]

Because the decline is floored and the aging term is unconditional, the forecast voltage of every module falls by at least 0.24 volts from the floor alone, and by about 0.74 volts once the aging term is included, over the ten-year horizon the produced configuration runs, whatever the module's observed history; a module survives the horizon only if it starts that far above its manufacturer's threshold.[101] SDG&E confirmed that "a module whose observed voltage history is flat or increasing is still assigned a minimum monthly decline rate of 0.002 V/month through application of the VDropMax floor," that some modules nonetheless do not cross their threshold within the horizon, and that it "does not maintain or routinely calculate the number or percentage of modules whose forecast monthly voltage

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[100] Response to CalAdv DR-005, Q29 (attachment "Gas Failure Forecast.zip", folder "sdge-it-da-gasmodulefailforecast-main": config/GasFailureForecast.json; forecast/Forecast.py; utils/DataUtilsFunc.py); see also Response to SBUA DR-003, Q2(a) ("please see SDG&E's response to CalAdv-SDGE-DR-005 for the code") and Response to UCAN DR-02, Q5.

[101] Response to CalAdv DR-005, Q29 (attachment "Gas Failure Forecast.zip", folder "sdge-it-da-gasmodulefailforecast-main": config/GasFailureForecast.json; forecast/Forecast.py; utils/DataUtilsFunc.py), config/GasFailureForecast.json (LOOKBACK_LENGTH 6; NUM_FORECAST_MONTHS 120; FORECAST_START 2026-01; VDropMax −0.002; AgingFactor 0.0001; AgeDelay 20) and forecast/Forecast.py (the aging term subtracts AgingFactor × (month − 20) in each month after month 20); UCAN arithmetic. The produced notebook is a replicate dated February 2026 (notebooks/GasFailureForecastReplicateFeb22_2026.py) with a January 2026 forecast start; SDG&E states that the forecast in its testimony was run in November 2025 (Ex. SDG&E-02 at SB-9 n.12) and has not stated that the November 2025 run used different settings. SDG&E describes the lookback as six months of historical monthly voltage observations (Response to CalAdv DR-002, Q4.e, Table 1; Response to SBUA DR-003, Q2(a)).

decline is determined by application of the VDropMax floor rather than the module's observed voltage history."[102]

Its own use-case workshops in February 2025 recorded the underlying problem: "Current failure forecasts are hard to predict, as there is no way to determine the remaining battery life for gas modules."[103] The voltage model, developed that same month,[104] answers it only by substituting a mandatory decline for the battery life SDG&E cannot observe. "Failure" for gas is thirty days without a response through an SM 1.0 electric meter, so a module orphaned by the loss of its mesh path is counted as a failed module, a point SDG&E concedes "complicat[es] attribution of root causes."[105] SDG&E points to automatic re-association and electric-meter-first replacement,[106] but it does not track whether a module counted as failed later regained communication, and its data query applies the thirty-day rule without that check.[107] SDG&E has also acknowledged that its previous gas forecast, presented in the 2024 GRC, "projected steep failure curves by 2029/2030 that did not align with actual field performance."[108]

Q. What do SDG&E's actual failures show?

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[102] Response to UCAN DR-02, Q5.a–b.
[103] Response to SDCP/CEA DR-001, Q3, attachment "AOTP Brainstorming Summary Deck" (Feb. 2025), slide 25; SDG&E has stated that the deck was not designated confidential, Response to SDCP/CEA DR-002, Q2.13.j. The slide notes that it "represents a consolidation of input from both SDG&E and SoCal Gas representatives."
[104] Ch. 2 Workpaper 1, tab "WP 2.3.1," cell A16 ("In February 2025 … the Updated Electric Failure Forecast Model and the Updated Gas Failure Forecast Model were developed"; "refreshed in 2025 November").
[105] Response to CalAdv DR-005, Q26.a.
[106] Response to CalAdv DR-002, Q4.j (mitigations (1) "Automatic Mesh Network Reassociation," under which a module pairs with another parent meter in range, and (2) "Replacement of the Non-Communicating Electric Meter," after which SDG&E waits thirty days before troubleshooting the module).
[107] Response to UCAN DR-02, Q4.iii; Response to SBUA DR-003, Q2(c) (SDG&E cannot distinguish battery depletion from orphaning); Response to CalAdv DR-002, Q4.i (it does not quantify the failure rate attributable to orphaning); Response to CalAdv DR-005, Q29, sql/GasThresholdZigbeeHistory.sql (the PresumedFail flag is set where the latest response date is more than thirty days old and not within two days of a removal date).
[108] Ex. SDG&E-02 at SB-9, lines 7–9.

A. Electric meters reaching thirty days of non-communication numbered 33,307 in 2024, 37,370 in 2025 and 20,265 in January through July 2026, about 34,700 on a straight-line annualized basis.[109] Gas modules numbered 6,620, 7,389 and 4,157 for the same periods, about 7,100 annualized.[110] A second series, produced to SBUA, is higher; where the series differ I use the range.[111] A monthly series SDG&E produced to the CCAs gives a similar picture (33,669 electric failures in 2024 and 38,201 in 2025; 7,630 and 7,791 gas), adds that over 2024–2025 "94% of electric meter failures have occurred within the ITR1 device class," and defines "significant levels" of failure as "failure counts that exceed SDG&E's workforce capacity to address."[112]

Against that, the forecast calls for 57,000 electric failures in 2026, 73,000 in 2027 and 92,000 in 2028, and for gas failures rising from 16,000 in 2026 to 274,000 in 2031.[113] For 2025, the forecast was 10 to 15 percent above SDG&E's reported electric actuals and 2 to 22 percent above its gas actuals.[114] For 2026, it is running 45 to 65 percent above electric actuals and roughly double gas actuals annualized from mid-year,[115] a gap the fourth-

[109] Response to UCAN DR-02, Q4.i (attachment "UCAN-SDGE-DR-002 Q4.i.xlsx").
[110] Response to UCAN DR-02, Q4.ii (attachment "UCAN-SDGE-DR-002 Q4.ii.xlsx").
[111] Response to SBUA DR-003, Q8(a) ("Annual Failure Quantities with Vendor-Recovered Amounts Pursuant to Warranties": 34,856 and 38,750 electric and 7,618 and 8,811 gas for 2024 and 2025; 19,493 electric and 4,050 gas including "year-to-date actuals through June 30, 2026"; SDG&E describes all of these failures as "premature when compared to the 17-year useful life").
[112] Response to SDCP/CEA DR-001, Q1.a–b (monthly tables, January 2024 through December 2025; annual totals are UCAN arithmetic). The three SDG&E series (this response, Response to UCAN DR-02, Q4.i–ii, and Response to SBUA DR-003, Q8(a)) differ by up to 5 percent for electric (2024: 33,307 to 34,856) and by up to 19 percent for gas (2025: 7,389 to 8,811). SDG&E has not reconciled them beyond a caveat that "reruns using the same methodology may produce different counts" as removal-date information is corrected, Response to UCAN DR-02, Q4.i–ii.
[113] Ch. 2 Workpaper 1, tab "WP 2.3.1" (Electric Failure Forecast and Gas Failure Forecast rows, 2025–2031).
[114] 2025 forecast of 43,000 electric and 9,000 gas, Ch. 2 Workpaper 1, tab "WP 2.3.1." Actuals: Response to UCAN DR-02, Q4.i–ii (37,370 electric; 7,389 gas); Response to SBUA DR-003, Q8(a) (38,750; 8,811); Response to SDCP/CEA DR-001, Q1.b (38,201; 7,791). Forecast divided by actual, minus one: electric 43,000 ÷ 38,750 = 1.11 and 43,000 ÷ 37,370 = 1.15; gas 9,000 ÷ 8,811 = 1.02 and 9,000 ÷ 7,389 = 1.22 (UCAN arithmetic).
[115] Response to UCAN DR-02, Q4.i–ii (20,265 electric and 4,157 gas, January through July 2026, annualized at twelve-sevenths: 34,740 and 7,126); Response to SBUA DR-003, Q8(a) (19,493 electric and 4,050 gas through June

quarter increase SDG&E describes would narrow but not close.[116] SDG&E's replacement counts run higher than its failure counts,[117] but replacements include exchanges for reasons other than failure, which SDG&E does not track by cause,[118] and it is failures the forecast predicts. Two years of actuals are not proof of the long-run failure curve, and I do not claim that the meters will not fail. The point is narrower and, I think, not debatable: a forecast for which SDG&E has produced no back-test or validation, that imposes a decline on every gas module regardless of what its voltage history shows, and that exceeded every 2025 actual SDG&E has reported and is running well above actuals in 2026 cannot carry the weight the Application places on it, which is to fix the timing of a $825 million program, including the roughly $420 million assigned to gas ratepayers for modules to be replaced in 2028–2030, on the strength of a meter failure cliff that has not begun.[119]

Q. Does the capacitor-defect cohort change your view?

A. It sharpens it. About one-third of the pre-2020 electric fleet carries capacitors from one supplier with date codes from November 2009 to March 2010, and that cohort accounted for about half of 2025 failures,[120] at district failure rates of 4 to 8 percent per year against

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30, 2026, doubled: 38,986 and 8,100). Electric 57,000 ÷ 38,986 = 1.46 and 57,000 ÷ 34,740 = 1.64; gas 16,000 ÷ 8,100 = 1.98 and 16,000 ÷ 7,126 = 2.25 (UCAN arithmetic).

[116] Ex. SDG&E-02 at SB-9 n.12 (SDG&E "has historically experienced a significant increase in failures during the 4th quarter"). January–July 2026 monthly rates of 2,895 electric and 594 gas (20,265 ÷ 7; 4,157 ÷ 7); even if August through December ran at twice those rates they would add 28,950 and 5,940, ending the year at about 49,200 electric failures against a forecast of 57,000 and about 10,100 gas failures against 16,000 (UCAN arithmetic).

[117] Response to CalAdv DR-006, Q58.a–b (46,457 electric meters and 27,196 gas modules replaced in 2025; records extend back to approximately 2021; 2026 figures are through July 15, 2026).

[118] Response to SBUA DR-003, Q8(a) ("SDG&E has not tracked these failures at the device level or by determined cause"); Response to CalAdv DR-005, Q28.g ("approximately 15,000 electric meters with the known capacitator [sic] issue were removed for other reasons outside of SDG&E's definition of failure").

[119] Ex. SDG&E-06 at CWB-7, Table 6-4. Gas module replacement capital is assigned 100 percent to gas under SDG&E's allocation practice whatever the schedule, Response to UCAN DR-02, Q11.b; the forecast determines when that cost is incurred, not whether gas ratepayers bear it.

[120] Response to CalAdv DR-004, Q2.f ("meters with identified faulty capacitors, though representing only one-third of the total population, accounted for half of the failures to date").

1 to 3.5 percent for the rest of the fleet.[121] That is an observed fact, and a phased program should act on it.

What the Application does not do is distinguish the cohort with a demonstrated defect from the two-thirds of the fleet failing at low single-digit rates, beyond an intent to prioritize areas with escalating failure rates;[122] it replaces both on the same four-year schedule. Asked whether it evaluated replacing the high-failure cohorts first while lower-failure cohorts remained in service, SDG&E pointed to its implementation plan and answered that "[a] detailed scenario analysis will occur as part of detailed deployment planning prior to initial deployment,"[123] and it has not explained how the cohort flag was assigned, given that a fifth of the flagged meters were installed in 2012–2019, years after the defective date codes.[124]

The composition of the flagged population has been requested twice: Cal Advocates asked for each date-code cohort separately and was told that the vendor's analysis "generalizes by date code,"[125] and SBUA asked for counts by serial number and was referred to a workbook organized by district and flag.[126] The vendor's own root-cause analysis,

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[121] CalAdv DR-004 workbook (about 389,000 cohort meters in service at the end of 2025; district rates, UCAN arithmetic). SDG&E has since reported the cohort at 497,381 meters installed and 403,401 in service as of June 23, 2026, with 20,823 cohort failures in 2025, and cautions that "[i]dentification within this population does not establish causation," Response to CalAdv DR-005, Q28.g.i–iv. The difference between that count and the 389,211 flagged meters in service at the end of 2025 in the forecast workbook is unexplained and is among the questions in UCAN-SDG&E-DR-03; I use the workbook figure because it is the population on which SDG&E's forecast and its district failure rates are computed.

[122] Ex. SDG&E-04 at BB/DC/DH-8, lines 6–8 ("SDG&E will prioritize deployment in geographic areas with escalating failure rates"); Response to CalAdv DR-005, Q27.a–b.

[123] Response to CalAdv DR-004, Q4.a–b.

[124] Response to SBUA DR-003, Q1(b), attachment "1b_SBUA_DR-003_SDGE Electric Failure Forecast Details.xlsx," tab "Electric CAGR Details" (in-year installs for the "Capacitor Issue? = Yes" rows: 92,269 of 461,810 in 2012–2019; UCAN arithmetic).

[125] Response to CalAdv DR-004, Q2.a.

[126] Response to SBUA DR-003, Q1(b).

produced in this proceeding, shows that the information exists and that the cohort is not uniform. [Confidential Information Begins]……… [Confidential Information Ends][127]

UCAN has served a further request asking how the flag is assigned and for the flagged population by installation year and capacitor date code.[128] Pending that response, the Attachment SG-2 model carries the cohort at two values: about 389,000 meters in service at the end of 2025, taking SDG&E's flag as assigned, and about 311,000, excluding the meters installed in 2012–2019.[129] The choice does not change any conclusion in this testimony, and if the later installs are not defective the point is sharpened rather than weakened, because the same observed failures would then be concentrated in a smaller population.

Whatever its size, the cost of the defect falls on ratepayers: the standard warranty ran five years from shipment, SDG&E "did not procure an extended warranty for the SM 1.0

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[127] Response to CalAdv DR-002, Q4.f, attachment "TURN-SEU-066_ATTACH_Q1B" (incumbent vendor, "SDG&E Blank Display Update," Sept. 2, 2021) (confidential), at 2, 5, 8–11.
[128] UCAN-SDG&E-DR-03, Q1 (served September 25, 2026; responses to Questions 1–5 requested by October 5, 2026).
[129] Attachment SG-2, "Inputs" (capacitor-cohort lever) and "Results" (cohort-size block).

equipment, as such an extended warranty did not meet the criteria established in the settlement approved by the Commission in D.07-04-043,"[130] and [Confidential Information Begins]………………..…………………..…………………………………………… .... [Confidential Information Ends][131]

D. SDG&E did not analyze alternatives, and its own procurement was designed for a failure-paced deployment (not a four-year mass replacement)

Q. What alternatives did SDG&E evaluate in its Application?

A. Only one alternative to deployment timing; the other alternatives and vendor bids SDG&E lists do not vary when SM 2.0 devices are installed.[132] SDG&E "considered the option of delaying implementation – i.e., beginning SM 2.0 implementation in 2031 or 2032 – and continuing to replace failing SM 1.0 electric meters and gas modules with like-for-like SM 1.0 devices in the meantime."[133] Asked in discovery whether its dual-head-end costs would change under a smaller pilot or a slower or phased deployment, SDG&E said it "did not assess alternative scenarios such as a smaller pilot, slower or phased deployment, or a longer period of operating two head-end systems in parallel than was assumed in the application" and pointed to its delay comparison,[134] and, other than those delay scenarios,

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[130] Response to CalAdv DR-002, Q4.g; Response to CalAdv DR-005, Q27.d.i–ii. SDG&E states that it "evaluated vendor warranty proposals and determined that the cost of obtaining extended warranty coverage exceeded the Commission-authorized threshold," Response to SBUA DR-003, Q8(c), and reports total vendor warranty recovery of $209,572 across all years, Response to SBUA DR-003, Q8(a).
[131] Response to CalAdv DR-002, Q4.g, attachment (Schedule J), §§ 1.1–1.4, 2.1(c)–(d) and 2.4 (confidential).
[132] Ex. SDG&E-03 at DT/BB-36, lines 9–15 (delayed implementation with like-for-like SM 1.0 replacement, gas-module battery replacement and smart inverters), and DT/BB-28 to DT/BB-35 (vendor evaluation); Reply of San Diego Gas & Electric Company to Protests (Feb. 2, 2026), Attachment A ("Loaded Cost Benefit Analysis – Replacement Strategies"); Response to CalAdv DR-002, Q4.h.
[133] Ex. SDG&E-03 at DT/BB-36, lines 18–21.
[134] Response to CalAdv DR-005, Q22.b.

its vendor comparison "and related procurement materials," it "has not prepared, and is not aware of, any separate comprehensive quantitative cost analysis comparing alternative deployment timing, deployment sequencing, deployment phasing, or sourcing strategies,"[135] and "has not performed any deployment scenario analysis since May 29, 2026."[136] It also "did not quantify the benefits of choosing the SM 2.0 solution over the SM 1.5 solution,"[137] the legacy-meter proposal that its public vendor comparison prices at $715 million against $825 million for the selected proposal.[138]

Q. Is SDG&E's delay scenario comparison a valid comparison?

A. No. Table 3-10 shows escalated direct costs of $762.0 million for deployment beginning in 2027, $1,021.4 million for a start in 2031 and $1,123.3 million for a start in 2032.[139] The "escalation impact" of $71.3 to $86.9 million is, in SDG&E's words, "the increase in SM 2.0 costs caused by inflation and other escalation factors," that is, the same dollars stated in later years' prices;[140] the workpaper contains no annual cash flows and no discounting.[141] The "incremental SM 1.0 direct costs" of $188.1 and $274.4 million are typed values in the workpaper with no supporting calculation,[142] the only calculation in the workbook produces different totals,[143] and, although SDG&E has identified the unit costs it says

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[135] Response to UCAN DR-02, Q3.
[136] Response to UCAN DR-02, Q6.a.
[137] Response to CalAdv DR-002, Q6.d.i (March 4, 2026). The same answer stated that SDG&E "intends to submit limited supplemental testimony to address quantified benefits of the proposed NextGen features"; SDG&E later served Ex. SDG&E-07-2E, a cost-benefit analysis limited to the two NextGen bundles it proposes to enable, which is addressed in Section VII.B. That analysis does not compare SM 2.0 with the legacy-meter bid or with any deployment schedule.
[138] Ch. 3 Workpaper 4 (public), tab "WP 3.9.1-C."
[139] Ex. SDG&E-03 at DT/BB-37, Table 3-10.
[140] Response to CalAdv DR-002, Q4.k.
[141] Ch. 3 Workpaper 3, tab "WP 3.10.1."
[142] Ch. 3 Workpaper 3, tab "WP 3.10.1," cells F16–F17 and I16–I17.
[143] Ch. 3 Workpaper 3, tab "Dileep_Rough," as served December 18, 2025 (removed September 14, 2026).

underlie them,[144] neither the volumes, escalation nor arithmetic behind those figures appears in any workpaper or was produced when asked.[145] At SDG&E's own 7.45 percent cost of capital, a dollar spent in 2031 is worth 75 cents in 2027 dollars; a nominal comparison that treats them as equal reverses under any positive discount rate.

This is the whole of SDG&E's analysis of deployment timing: asked to identify its evaluation of "other phased deployment approaches," SDG&E pointed to the same discussion at DT/BB-36 and to Attachment B of its Reply to Protests,[146] which restates the same three figures ($762.0, $1,021.4 and $1,123.3 million) under the title "Direct Cost Benefit Analysis – Recommended Solution Deployment Scenarios."[147] [Confidential Information Begins]…………………………………………………..………………
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….[Confidential Information Ends][148]

Q. What does SDG&E's procurement record show about the deployment schedule?

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[144] Response to SBUA DR-003, Q8.e (July 17, 2026): $169 to $200 per electric meter and $119 to $139 per gas module in 2025 dollars, depending on whether internal or contractor labor installs the device, stated to be "the direct per unit replacement costs used to calculate the incremental impact of delay scenarios as shown in the testimony David H. Thai & Bradley M. Baugh – Chapter 3, Table 3-10."
[145] Response to UCAN DR-02, Q2 (referring only to its response to Q1).
[146] Response to CalAdv DR-004, Q4.c.iv.
[147] Reply of San Diego Gas & Electric Company to Protests (Feb. 2, 2026) at 7 and Attachment B ("Direct Cost Benefit Analysis – Recommended Solution Deployment Scenarios": $762.0, $1,021.4 and $1,123.3 million; "benefits (avoided costs)" of $259.4 and $361.3 million against the four- and five-year delays).
[148] Ch. 3 Workpaper 3, tab "WP 3.10.1," cells F18 and I18, and tab "Updated IT Assumption," as served December 18, 2025 (removed September 14, 2026). SDG&E declined to confirm the match when asked (Response to UCAN DR-02, Q2.c, answered only by reference to the response to Q1). [Confidential Information Begins]……………..…
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[Confidential Information Ends]

A. [Confidential Information Begins]……………………………………..………..…… ………………………………………………………………………………………… ………………………………………………………………………………………… ....[Confidential Information Ends].[149] [Confidential Information Begins]………………..………………………………………………………. …………..…………………..……………………………………………………………… ……………………………………………..……………………………………… …..[Confidential Information Ends].

[Confidential Information Begins]…………………………………………………….…… ………..…………………………………………………..…………..………………… …..………………………………………………………………………………… ………………………………………...[Confidential Information Ends].[150] [Confidential Information Begins]……………………..……………………………………….…… ………..…………………………………………………..…………..……………… ....[Confidential Information Ends][151]

[149] Response to CalAdv DR-002, Q5.b, RFP package, “Appendix AB_Forecasted Endpoint Volumes” [confidential]. The procurement record is designated confidential in its entirety.

[150] Response to CalAdv DR-002, Q5.b, “SM 2.0 Bid Improvement” (June 27, 2025), § 4.4 [confidential].

[151] Response to CalAdv DR-002, Q5.b, Selected Vendor’s responses to Appendix C1 (May 12, July 9 and October 3, 2025); “SM 2.0 Bid Improvement” (June 27, 2025), §§ 4.2.1 and 4.4; Selected Vendor’s “Response to SDGE Follow up Questions” (Oct. 7, 2025), item 2 [confidential]. [Confidential Information Begins]……...………………..… ………..……………………………………………..………...…………………...………………………… ………………………………………………………………………...…………………………………………… … ....[Confidential Information Ends] no agreement has been executed (Response to UCAN DR-02, Q6.b). Attachment SG-2 applies SDG&E’s Application unit costs to every scenario as a common assumption; it does not assume that those prices are contractually held for a slower schedule.

[Confidential Information Begins]………[Confidential Information Ends][152] [Confidential Information Begins]…… [Confidential Information Ends][153] Table 2 sets the two schedules side by side.

Table 2. The "Break and Replace 2.0" failure forecast (hidden workpaper tab, since withdrawn), [Confidential Information Begins]…………………………………………………………………………………………[Confidential Information Ends] and the Application schedule[154]

Electric meters

Year	Failure forecast	Confidential	Confidential	Application (Dec. 2025)
2026	64,000	Confidential	—	—
2027	84,000	Confidential	Confidential	132,363
2028	108,000	Confidential	Confidential	388,681
2029	132,000	Confidential	Confidential	653,596
2030	152,000	Confidential	Confidential	459,858
2031	161,000	Confidential	—	—
2032	151,000	Confidential	—	—
2033	120,000	Confidential	—	—
2034	82,000	Confidential	—	—
2035	55,000	Confidential	—	—
Total	**1,109,000**	**Confidential**	**Confidential**	**1,634,498**

Gas modules

[152] Ex. SDG&E-03 at DT/BB-37 to DT/BB-39; Ex. SDG&E-04 at BB/DC/DH-9, lines 4–6.
[153] Ex. SDG&E-03 at DT/BB-36, lines 10–15 ("For the reasons discussed below, none of these options are feasible."); Response to CalAdv DR-005, Q22.b.
[154] Ch. 2 Workpaper 1, tab "Failure Reforecast," rows 21–22, as served December 18, 2025 (removed September 14, 2026).

Year	Failure forecast	Confidential	Confidential	Application (Dec. 2025)
2026	16,000	Confidential	—	—
2027	28,000	Confidential	Confidential	30,904
2028	54,000	Confidential	Confidential	224,038
2029	105,000	Confidential	Confidential	399,968
2030	184,000	Confidential	Confidential	297,851
2031	244,000	Confidential	—	—
2032	250,000	Confidential	—	—
2033	4,000	Confidential	—	—
Total	**885,000**	**Confidential**	**Confidential**	**952,761**

Sources: Ch. 2 Workpaper 1, "Failure Reforecast" (2026–2035 columns);[Confidential Information]………………[Ends][155] *Application volumes from Ch. 3 Workpaper 1, notes A29–A30.*[156] *[Confidential Information Begins]…………………………………………………………… ……………………………………………………………………………………[Confidential Information Ends]*[157] *[Confidential Information Begins]…………………………………………………………………… ……… ……… ……… [Confidential Information Ends]*

Q. How do you reconcile the procurement record with SDG&E's statement that it "did not assess alternative scenarios such as a smaller pilot, slower or phased deployment" for its dual-head-end costs?

A. The two are consistent only in a narrow sense. SDG&E's request for proposals specified a deployment schedule substantially longer than the four years in the Application, paced to its own forecast of device failures, and both bidders priced that schedule; the four-year

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[155] Response to CalAdv DR-002, Q5.b, RFP package, "Appendix AB_Forecasted Endpoint Volumes" and "SM 2.0 Bid Improvement" (June 27, 2025), § 4.4 [confidential].

[156] Ch. 3 Workpaper 1, notes A29–A30; Ex. SDG&E-04, Figure 4-3.

[157] [Confidential Information Begins] .... [Confidential Information Ends]The visible tab (Ch. 2 Workpaper 1, tab "WP 2.3.1 Failure Rate Analysis," rows 10–11, "Updated Failure Forecast Summary (as of November 2025)") forecasts 73,000, 92,000, 111,000 and 127,000 electric meters for 2027–2030. SDG&E withdrew the hidden tab on September 14, 2026 as "hidden tabs with incomplete internal draft material that was inadvertently included in the production," stating that the replacement files "remove the hidden tabs and contain no other changes" (SDG&E e-mail notice to parties, "Replacement Workpapers" (Sept. 14, 2026)); compare Response to UCAN DR-02, Q1 ("incomplete, internal draft material").

schedule was introduced afterward, in a request that the bidders re-price it.[158] So a slower, failure-paced deployment was not merely conceivable: [Confidential Information Begins].. .... [Confidential Information Ends]

What SDG&E did not do is compare the two schedules it had priced, and that is what its discovery answers confirm: it "did not assess" how its dual-head-end costs would change under a slower or phased deployment,[159] apart from its delay scenarios and vendor comparison, it "has not prepared, and is not aware of, any separate comprehensive quantitative cost analysis comparing alternative deployment timing, deployment sequencing, deployment phasing, or sourcing strategies,"[160] it "has not performed any deployment scenario analysis since May 29, 2026,"[161] a "detailed scenario analysis will occur as part of detailed deployment planning prior to initial deployment,"[162] and, asked for the revenue requirement of an authorization limited to the platform and the initial tranche, it answered that the phases "were not developed, planned, or costed as stand-alone programs capable of independent authorization and operation" and that it "has not prepared … the revenue requirement, cost allocations, or operational assumptions necessary to evaluate" such an authorization.[163] It also "did not evaluate third-party ownership, leasing, or metering-as-a-service arrangements" for any component other than software hosting.[164] [Confidential Information Begins]……………………………………………….……

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[158] Response to CalAdv DR-002, Q5.b, "Appendix AB_Forecasted Endpoint Volumes" and "SM 2.0 Bid Improvement" (June 27, 2025), § 4.4 [confidential].
[159] Response to CalAdv DR-005, Q22.b.
[160] Response to UCAN DR-02, Q3.
[161] Response to UCAN DR-02, Q6.a.
[162] Response to CalAdv DR-004, Q4.a.
[163] Response to SBUA/TURN DR-001, Q3.a (Sept. 21, 2026).
[164] Response to SBUA/TURN DR-001, Q15.a.

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The request for proposals was written for the longer schedule in terms, not only in volumes. [Confidential Information Begins]………………………………………………………. ………………………………………………………………….....…………..……… …………..……………………………………………………………………………… ………………………………………………………………………………………… ………………………………………………………………………………………… ……………..…………………………………………………………………………… ………………………………………………………………………………………… ....[Confidential Information Ends][166] [Confidential Information Begins] ………………………………………………………………….....…………..……… .... [Confidential Information Ends][167]

Nor was the comparison beyond SDG&E's means. [Confidential Information Begins]…… ………………………………………………………………………………………… ………………………………………………………………………………………… …………………………………………………………………………………………

[165] Response to UCAN DR-02, Q1 (SDG&E's September 14, 2026 notice).
[166] Response to CalAdv DR-002, Q5.b, [Confidential Information Begins]………………………………………. ……………………………………………………………………....…………..…………………..……………… … ....[Confidential Information Ends] [confidential].
[167] Response to CalAdv DR-002, Q5.b, RFP package: "Appendix A_Master RFP Document_Revised 040125" at 2–3; "Appendix C1" (ASSUMPTIONS, items a and c); "Appendix N10" § 8.1.1(k); "Appendix PR" §§ 2.1, 2.4 and 8.1; Selected Vendor "Response to SDGE Follow up Questions" (Oct. 7, 2025), item 1 (all confidential). [Confidential Information Begins]..[Confidential Information Ends] no agreement has been executed (Response to UCAN DR-02, Q6.b: "SDG&E has not executed a final agreement with the proposed vendor.").

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…….[Confidential Information Ends][168] UCAN has requested those deliverables.[169]

The Commission asked in D.24-12-074 for a comprehensive comparison of replacement strategies.[170] The record shows that SDG&E had the inputs for that comparison in hand by mid-2025, commissioned it, and has not produced it, which is the gap the phased authorization in Section IV.F is designed to close.

E. Present-value comparison of alternative deployments

Q. How did you construct the comparison?

A. Attachment SG-2 compares four scenarios on a common decision date of the fourth quarter of 2027 and first installations in 2028:

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[168] Response to CalAdv DR-005, Q25.a, attachment "25a_CalAdvocates_DR-005_EY_REDACTED_CW59791-ExtA1" (Amendment No. 1, effective April 1, 2025) (confidential), at 6, 9, 12, 15 and 18–20; see also "-ExtA3" (Amendment No. 3, Feb. 6, 2026) at 5 ("Program Financial Model … with the ability to run multiple scenarios") and 9 ("alternative scenario quantification").
[169] UCAN-SDG&E-DR-03, Q3.
[170] D.24-12-074 at 674.

1. **Scenario A, the Application schedule:** SDG&E's four-year volumes, shifted one year.
2. **Scenario B, failure-led:** from 2028, each failed SM 1.0 device is replaced with an SM 2.0 device; the residual fleet is swept in 2034–2035, Confidential Information Begins] .... [Confidential Information Ends], so that every SM 2.0 installation is complete by the end of 2035, [Confidential Information Begins]……………………………………………………………………...… .... [Confidential Information Ends][171]
3. **Scenario C1, Phase 1 followed by mass deployment:** in 2028–2029, failures are replaced and the capacitor-defect cohort is proactively swept (about 150,000 meters in 2028, sized to the date code with the highest failure rate, and the remainder of the cohort in 2029), together with the SM 1.0 gas modules at the swept premises, which would otherwise lose the electric meter through which they communicate; in 2030, while the Commission's checkpoint review runs, only failures are replaced;[172] the remaining fleet is then replaced in 2031–2032, at about 540,000 electric meters and 246,000 gas modules a year on SDG&E's forecast, below the Application's own peak years.

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[171] Response to CalAdv DR-002, Q5.i and n.8 Confidential Information Begins]…………………………………… ………………………………...……..……..…………………..…………………………………………………… … .... [Confidential Information Ends] Response to UCAN DR-02, Q10.b (SDG&E "did not receive an unconditional, binding commitment" for continued SM 1.0 supply or support beyond existing contractual commitments).

[172] Once the cohort has been swept, the C1 and C2 sheets reduce each year's failures by the cohort's share of SDG&E's expected failures for that year, taken from SDG&E's forecast workbook: 54 percent in 2026–2028, 50 percent in 2030, 46 percent in 2031, 37 percent in 2032 and 24 percent in 2033, as the cohort exhausts while SDG&E's forecast failure rate for the rest of the fleet rises from 3 percent to 17 percent a year. On the actuals-trend path the reduction is the cohort's 53 percent share of 2025 failures. Attachment SG-2, "Inputs," "SDG&E's electric failure forecast by capacitor flag" (Response to CalAdv DR-004, Q1.b workbook, tab "Electric CAGR Details"; UCAN arithmetic).

4. **Scenario C2, Phase 1 followed by continued failure-led replacement:** the same Phase 1, then failure-led replacement in 2030–2033, with the residual fleet swept in 2034–2035, so that, as in Scenario B, every installation is complete by the end of 2035.

Every scenario replaces the same 1,634,498 electric meters and 952,761 gas modules and includes the same Foundational Technology platform, the same NextGen capabilities, the same program management, and the same recurring connectivity, head-end and subscription charges on endpoints in service through 2046; the scenarios that operate SM 1.0 beyond 2031 also carry the SM 1.0 head-end operating cost[173] and the cost of the Itron cloud-hosted head-end path from SDG&E's own workpapers.[174] Every scenario also carries SDG&E's cost of decommissioning the SM 1.0 network hardware, placed in the last year of its own deployment and the years on either side, as SDG&E places it in the Application, and the per-device removal, testing and disposal costs from SDG&E's workpapers.[175] Like-for-like SM 1.0 replacements in 2026–2027 and the SM 1.0 legacy forecast are common to every scenario and excluded.

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173 Response to CalAdv DR-005, Q22.a (dual head-end cost table).
174 Ch. 3 Workpaper 3, tab "Updated IT Assumption," as served December 18, 2025 (removed September 14, 2026). [Confidential Information Begins]…………………………………………………………………………………… ……………………………………………………………………………………..………..………………… ……… ……… … ....[Confidential Information Ends], the continuation-cost sensitivity below, which doubles and triples these costs, bounds the effect of a different price for the path.
175 Ch. 3 Workpaper 2, tab "WP 3.4.8 (HardwareDecomiss)," row 10 ($4.9 million over 2029–2031, SDG&E's last deployment year and the years on either side), which the Response to SBUA/TURN DR-001, Q9.b (Sept. 21, 2026), identifies as the SM 1.0 network decommissioning cost; Attachment SG-2, "Inputs," SDG&E program series as filed ("SM 1.0 network hardware decommissioning"). Device removal, testing and disposal costs, including SDG&E's electric recycling credit, are carried per device from Ch. 3 Workpaper 1, tabs "WP 3.2.1-C" (rows 24–25) and "WP 3.3.1-C" (rows 23–24), the rows the same response identifies.

Unit costs are SDG&E's [Confidential Information Begins]…………………………….. ………………………………[Confidential Information Ends]; $5.50 and $22 of removal expense, with failure-led installations at SDG&E's own like-for-like labor rates, in-house up to 60,000 devices a year and contractor above that), escalated at the rates in SDG&E's delay workpaper; the revenue requirement uses SDG&E's authorized return, capital structure, tax rates and loaders;[176] and the present value is taken at 7.45 percent to 2026, as in SDG&E's cost-benefit analysis. I use a twenty-year life for meters and modules in the base case, for the reasons in Section V, and show fifteen years as a sensitivity.

The three failure paths are SDG&E's forecast as filed; an actuals-trend path that starts from the 2024–2026 actuals and grows electric failures 10 percent and gas failures 15 percent per year as the fleet ages; and the mid-point of the two. The growth rates on the actuals path are assumptions, not a fitted model: they are set close to or above the growth in failure counts observed from 2024 to 2025 (about 12 percent for both electric and gas),[177] and the gas rate is set higher because battery-driven failures are expected to accelerate as the modules age. The result is not sensitive to the choice.[178] Once the cohort has been swept, the actuals-trend

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[176] Ex. SDG&E-06 at CWB-6, lines 6–12 and n.10 (7.45 percent). The components are the 2025 values under the cost-of-capital mechanism: 52.00 percent common equity at 10.23 percent, 2.75 percent preferred at 6.22 percent and 45.25 percent long-term debt at 4.34 percent, on the capital structure adopted in D.22-12-031 (SDG&E Advice Letter 4553-E/3369-G (Nov. 14, 2024; effective Jan. 1, 2025), Table 1). The Commission adopted SDG&E's 2026–2028 cost of capital in D.25-12-043 on December 18, 2025, the day the Application was filed: the same capital structure, a 9.93 percent return on equity, 4.59 percent cost of debt and a 7.41 percent rate of return. Attachment SG-2 keeps SDG&E's 7.45 percent for comparability with Table 6-4; at the 2026–2028 values every present-value cost is slightly lower and no ranking changes.

[177] Response to UCAN DR-02, Q4.i–ii (electric meters and gas modules reaching 30 consecutive days of non-communication: electric 33,307 in 2024 and 37,370 in 2025; gas 6,620 and 7,389). On the annual failure quantities in the Response to SBUA DR-003, Q8.a (electric 34,856 and 38,750; gas 7,618 and 8,811), the growth is about 11 percent for electric and 16 percent for gas.

[178] Attachment SG-2, "Inputs," SM 1.0 failure paths block (the growth rates are levers). With both rates at the observed 12 percent, Scenario C2's advantage on the actuals path is $91 million rather than $92 million; at 15 and 20 percent, $82 million; at 20 and 25 percent, $74 million; at 26 percent for both, $64 million, with electric failures then reaching more than double SDG&E's own forecast for 2035. The 26 percent rate is the compound annual growth from the 18,746 failed electric meter orders SDG&E reported replacing in 2022 in its 2024 general rate case

path implies that the rest of the pre-2020 fleet fails at about 3 percent a year in 2030, rising to about 4.5 percent by 2033, at the top of the 1 to 3.5 percent range observed by district in 2024–2025 and a little above it by the end; SDG&E's own forecast has the same meters failing at 9 percent a year in 2030 and 17 percent by 2033, because it compounds their failure rate without bound.[179]

Q. What are the results?

A. Table 3 shows the present value of the revenue requirement for 2024 through 2071 under each scenario and failure path.

Table 3. Present value of the revenue requirement paid by ratepayers, 2024–2071, in 2026 dollars at 7.45 percent ($ million)

Scenario	SDG&E forecast	Mid-point	Actuals trend
A. Application schedule (decision Q4 2027)	937.1	937.1	937.1
B. Failure-led, residual sweep 2034–2035	902.0 (−35.1)	855.8 (−81.2)	809.2 (−127.9)
C1. Phase 1 (2028–2029), checkpoint year 2030, mass 2031–2032	934.3 (−2.8)	923.2 (−13.8)	909.8 (−27.3)
C2. Phase 1 (2028–2029), then failure-led, residual sweep 2034–2035	925.0 (−12.1)	892.1 (−45.0)	845.1 (−92.0)

Source: Attachment SG-2, "Results." Differences from Scenario A in parentheses; a negative figure is a lower cost to ratepayers.

(Response to PAO-SDGE-176-MCL, Q1.e (Feb. 9, 2023), served in this proceeding with the Response to TURN DR-001, Q4.b) to the 37,370 non-communication count for 2025 (Response to UCAN DR-02, Q4.i); on SDG&E's annual failure quantities (21,851 for 2022 and 38,750 for 2025, Response to SBUA DR-003, Q8.a) the compound growth is 21 percent.

[179] Attachment SG-2, "Inputs," check block "Implied annual failure rate of the residual electric fleet": each path's electric failures after removing the cohort's share, divided by the non-cohort meters still in service on that path (starting from SDG&E's 886,126 expected non-cohort operating units in 2026). The actuals-trend path gives 3.0, 3.4, 3.8 and 4.4 percent for 2030 through 2033; SDG&E's forecast gives 8.6, 11.1, 13.9 and 17.0 percent. The observed district rates are from the Response to CalAdv DR-004, Q1.b workbook, tab "Electric CAGR Details" (UCAN arithmetic).

Three things follow. First, on SDG&E's own failure forecast, every alternative costs ratepayers less in present value than the Application's schedule, and the failure-led designs cost 1 to 4 percent less. Second, the advantage grows as the failure path approaches SDG&E's actual experience: on the actuals trend, the phased failure-led design (C2) costs about $92 million, or 10 percent, less. Third, the checkpoint itself costs nothing: Scenario C1, which holds 2030 to failure replacement while the Commission reviews and then sweeps the remaining fleet in 2031–2032 at a pace below the Application's own peak years, is $3 million below the Application on SDG&E's forecast, and it preserves the ability to capture the larger savings if, as the actuals so far indicate, the cliff does not arrive on schedule.

Scenario B, which replaces devices only as they fail with no proactive sweep of the capacitor cohort, is the bookend of the range rather than my recommendation: it is the lowest-cost design on every path, $35 million to $128 million (4 to 14 percent) below the Application, but it leaves the cohort with a demonstrated defect in service until each meter fails. That asymmetry is the case for a checkpoint: the Commission need not decide today which failure path is right, because the phased design is close to the Application's cost if SDG&E is right and substantially cheaper if it is wrong.

Q. How sensitive are the results?

A. The ranking on the actuals trend is stable under every case I tested. On SDG&E's own forecast, where the phased design's advantage is $12 million, the ranking holds under the higher discount rate, fifteen-year lives and the NextGen deferral, and reverses by $2 to $7 million under the lower discount rate, the NextGen-off case and a 25 percent installation premium; the one input that moves it further is the cost of keeping SM 1.0 running, discussed below. At a 9.45 percent discount rate the Application's present-value cost is $794.8 million and Scenario C2's $771.4 million; with fifteen-year lives, $919.7 and $907.7 million; at 5.45 percent, $1,118.6 and $1,125.3 million, because the lower rate gives more weight to the later years in which the phased design is still replacing meters. Installation labor is priced in the base case on SDG&E's own terms: its crews replace a failed electric meter for $44 of labor and a gas module for $27, a contractor for $75 and $47, and it would use contractors only when failure volumes exceed the roughly 60,000 devices a year its workforce can handle,[180] so the model prices the first 60,000 failure-led devices a year at the in-house rate, the rest at the contractor rate, and the route-based sweeps at SDG&E's mass-deployment cost. Pricing every installation at the mass-deployment cost instead would lower Scenario C2 by about $10 million on SDG&E's forecast and $3 million on the mid-point and raise it by about $2 million on the actuals trend, where failure volumes stay nearer the in-house capacity and SDG&E's own rate is the cheaper one.[181] A

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[180] Response to CalAdv DR-002, Q5.b, RFP package: [Confidential Information Begins]……………………………………………………………..……………………………………………… …..[Confidential Information Ends] SDG&E's installation unit costs are those of an installation vendor doing route-based mass deployment (Ex. SDG&E-04 at BB/DC/DH-7, lines 6–7). Failure-led work: Response to SBUA DR-003, Q8.e (2025 dollars, direct costs, table: labor of $44 in-house and $75 contractor per electric meter, $27 and $47 per gas module; "SDG&E has not yet utilized external resources (contractors)" for failed-device replacement and "would only consider" them when failure volumes "materially exceed the capacity of its existing internal workforce"); Ex. SDG&E-03 at DT/BB-38, lines 6–7 ("At present, SDG&E can replace approximately 60,000 devices per year"). The capacity is SDG&E's current workforce, which it says it would expand for its own 2030–2032 failures; holding it fixed is the conservative reading. The Application prices every installation as route-based, although meters that fail ahead of the route under its schedule are also replaced reactively; the split is applied only to the alternatives, which is also conservative.

[181] Attachment SG-2, "Results," no-labor-split block (sheets "C2-P1 IPmass," "C2-P2 IPmass" and "C2-P3 IPmass"): $914.6, $888.9 and $847.5 million against $925.0, $892.1 and $845.1 million in the base case. SDG&E's in-house rate is below the mass-deployment installation and removal cost the model otherwise applies[Confidential Information Begins][Confidential Information Ends]; the rates, the capacity and the switch are levers on "Inputs," and the failure-led share of each year's installations is shown on every scenario sheet.

cruder test, a 25 percent premium on every installation and removal in the scenario, sweeps included, puts Scenario C2 $5 million above the Application on SDG&E's forecast and $22 million and $63 million below on the other two paths.[182]

If the NextGen capabilities are never implemented, every scenario's present-value cost falls by roughly $85 to $105 million, because the NextGen connectivity tier and capability subscriptions recur for the life of the platform.[183] If the NextGen decision is instead deferred to the checkpoint, with the same capabilities starting in 2031 rather than 2028, the present-value cost falls by only about $9 to $10 million under the Application and under Scenario C2 (to $926.9 and $915.9 million), because the recurring charges move rather than disappear.[184] On the cost side, then, deferring the decision saves ratepayers about $10 million rather than costing them anything, although it would also defer the NextGen benefits SDG&E's supplemental testimony estimates;[185] what the decision governs is whether the recurring charges are incurred at all, which is why it belongs at the checkpoint (see Section IV.F).

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[182] Attachment SG-2, "Results," installation-premium block (sheets "C2-P1 IP25," "C2-P2 IP25" and "C2-P3 IP25"): $942.5, $915.0 and $873.8 million against $937.1 million for the Application; the premium applies to the route-based sweeps as well as to failure work.

[183] Attachment SG-2, "Results," sensitivities block (sheets "A NGoff," "B-P1 NGoff," "C1-P1 NGoff" and "C2-P1 NGoff"). The figure is larger than SDG&E's own present value of the incremental NextGen costs, $59.9 million ($24.9 million for the grid-operations bundle and $35.0 million for Customer Insights; Ex. SDG&E-07-2E at NR/DT/MW-28, Table V-1, and NR/DT/MW-29, Table V-2), and than the $50.2 million of loaded NextGen cost in the Application (Ch. 3 Workpaper 4 (public), tab "WP 3.9.1-C," cell E23), because it is the present value of the revenue requirement including the NextGen connectivity tier and capability subscriptions through 2046, which SDG&E's figures stop at 2031 or treat outside the Application (see Section V.B).

[184] Attachment SG-2, "Results," sensitivities block (sheets "A NG31" and "C2-P1 NG31"; the NextGen start year is a lever on Inputs).

[185] Ex. SDG&E-07-2E at NR/DT/MW-28, lines 8–14 and Table V-1 (as corrected: $3.3 million, $22.2 million and $41.9 million, $67.4 million in total, present value, for the grid-operations bundle), and NR/DT/MW-29, lines 2–7 and Table V-2 ($100.9 million for Customer Insights).

The one input to which the ranking on SDG&E's own forecast is sensitive is the cost of keeping SM 1.0 running after 2031, discussed in the next answer: if those continuation costs are doubled, Scenario C2 costs about $17 million more than the Application on SDG&E's forecast and still costs $63 million less on the actuals trend; if they are tripled, C2 costs $46 million more on SDG&E's forecast and $34 million less on the actuals trend. The conclusion on the actuals path is therefore robust, and the conclusion on SDG&E's own path holds so long as the continuation costs stay below about 1.4 times SDG&E's own figures.[186]

Q. What SM 1.0 costs do the slower scenarios carry, and what do they leave out?

A. Every scenario that operates SM 1.0 devices after 2031 carries six continuation costs in each year until the last device is replaced: the operating, maintenance and support cost of the SM 1.0 head-end, about $2.0 million a year, taken from SDG&E's own dual-head-end table;[187] [Confidential Information Begins]…………………………………….……………….. .... [Confidential Information Ends];[188] from SDG&E's September 21 breakdown of the cost of operating the two systems concurrently, about $1.0 million a year of RFLAN network-mitigation capital, about $0.27 million a year of SM 1.0 IT staff operations and about $0.08 million a year of head-end IT support;[189] and

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[186] Attachment SG-2, "Results," sensitivities block.
[187] Response to CalAdv DR-005, Q22.a.
[188] Ch. 3 Workpaper 3, tab "Updated IT Assumption," as served December 18, 2025 (removed September 14, 2026).
[189] Response to SBUA/TURN DR-001, Q9.a (Sept. 21, 2026), table (thousands of dollars): network-mitigation capital of $800,000 to $1,200,000 a year in the memorandum account through 2030; IT operations of $237,000 to $280,000 a year (head-end and all other SM 1.0 systems); head-end IT support of $70,000 to $81,000 a year. The head-end maintenance in the same table, $1.57 million in 2026 rising to $1.95 million in 2030, matches the dual-head-end table in the response to CalAdv DR-005, Q22.a. Attachment SG-2 reproduces both tables on its "Inputs" sheet and computes each lever from them by formula: the 2030 values for the head-end ($2.0 million), IT operations ($271,000) and IT support ($79,000), and the 2026–2030 average for network mitigation ($980,000). Note that the table's "SM 1.0 maintenance – MDMS" line is not carried, because SDG&E describes the MDMS as a persistent

the recurring cellular backhaul for the SM 1.0 network, about $0.6 million a year on SDG&E's own forecast.[190] Each is escalated at SDG&E's O&M rate and charged in every year after 2031 in which SM 1.0 devices remain in service. For Scenario C2 they total about $46 million, loaded, over 2030–2035 (the one-time migration cost falls in 2030–2031), and they are included in the present-value costs in Table 3.

The comparison still does not charge the slower scenarios for smart-meter business operations staff, for any premium the incumbent might charge for extended support after 2028, for a further head-end upgrade if SM 1.0 operation extends past October 2031, or for added network maintenance as the mesh thins.[191] SDG&E states that ongoing SM 1.0 maintenance costs "will be recovered through SDG&E's base business,"[192] that operations staff time "cannot be meaningfully or accurately attributed to one platform such as the head-end,"[193] and its own estimate assumes no premium: the September 21 table notes that the vendor's "maintenance cost MSA ends in 2028, and SDG&E does not have firm maintenance costs starting in 2028. For this estimate, we've assumed the same costs with continued standard escalations."[194]

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system that continues after SM 2.0 deployment, and its "IT support – all other smart meter systems" line is not carried, because SDG&E states that it mixes retiring and persistent systems and cannot be broken out; the doubling and tripling in the sensitivity covers the SM 1.0 share of that line.

[190] Response to CalAdv DR-003, Q6.d.i (March 31, 2026) (SDG&E "forecasts annual recurring cellular SM 1.0 costs of approximately $600K/year"); Attachment SG-2, "Inputs" ("SM 1.0 recurring cellular backhaul").

[191] Response to UCAN DR-02, Q9.e (an OWCE upgrade would be required "if Smart Meter 2.0 meter and module deployment extends into 2032," unless the cloud-hosted path carried in the model serves as that upgrade; SDG&E "has not estimated the incremental annual cost of extending the Smart Meter 1.0 / Smart Meter 2.0 dual head-end overlap period by one, two, or three years beyond 2031"); Response to CalAdv DR-003, Q13.c ("As the mesh degrades with meter attrition, additional operational effort would be required to maintain network performance."). The doubling and tripling of the continuation costs in the previous answer is offered as the bound for these items.

[192] Response to CalAdv DR-003, Q10.d–e.

[193] Response to CalAdv DR-005, Q22.a.

[194] Response to SBUA/TURN DR-001, Q9.a, note **.

Carrying those costs for up to four more years is a real cost of the slower scenarios, which is why the sensitivity above doubles and triples the continuation costs, and why UCAN has asked SDG&E to identify and quantify every SM 1.0 cost it would incur in 2032–2036 if the fleet were run down by failure rather than swept.[195] As a point of comparison, SDG&E's own delay case carries about $10 to $11 million a year of head-end hosting, IT, network and contingency for each year the two systems overlap, against UCAN's six continuation costs of about $8.6 to $9.2 million a year direct, or $10 to $11 million loaded, for 2032–2035 (head-end O&M $2.0 million, Itron hosting $3.6 million plus the $3.1 million one-time move, network mitigation $1.0 million, cellular backhaul $0.6 million, IT operations and support $0.35 million).[196]

Q. Does the comparison overstate the case for the phased design?

A. No. If anything it understates it, because three things that favor the phased design are left out of the present-value costs. The first is the option the checkpoint creates: the ability to size Phase 2 to observed failure rates, to the vendor's actual unit-cost and installation performance, and to any change in technology or in the head-end support situation. The model assigns that option no value, and a program that commits 1.6 million meters at a

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[195] UCAN-SDG&E-DR-03, Q2.

[196196]SDG&E: Ch. 3 Workpaper 3, tab "WP 3.10.1," line 3 (Foundational Technology, "Incremental 1.0": $26,095,770 for the four-year delay and $30,927,569 for the five-year delay) and line 6 (contingency: $17,103,741 and $24,949,049), together $43.2 million over four years and $55.9 million over five, or $10.8 and $11.2 million a year. The Foundational Technology increment is the incumbent's hosted head-end priced in the withdrawn "Updated IT Assumption" tab, escalated at 3 percent a year; the contingency is SDG&E's contingency on the whole incremental amount, including the device purchases, so the per-year figure is if anything generous to SDG&E. [Confidential Information Begins]……………………………………………………………………………………… ….. [Confidential Information Ends] UCAN: Attachment SG-2, sheet "C2-P1," SM 1.0 continuation rows, 2032–2035, before and after the 17.5 percent contingency, overhead and AFUDC loader on Inputs; the one-time migration cost falls in 2030–2031.

single decision has none. The second is price. The obvious objection to phasing is that the bid pricing assumed a full-scope award; it did not. [Confidential Information Begins]…… ……………………………………………………………………………………… ……………………………………………………………………………………… …...............................[Confidential Information Ends][197] The third is the obligation a mass deployment would create under the contractual terms now in the record: [Confidential Information Begins]………………………………………….…[Confidential Information Ends][198] [Confidential Information Begins] .... [Confidential Information Ends][199] The comparison assigns no cost to the risk that those terms would leave ratepayers with an obligation that outlasts any finding that the program should have been slowed.

F. Recommendations

Q. What is your recommended deployment process?

A. I recommend that the Commission authorize the program in two phases with a checkpoint between them.

Phase 1 (through December 31, 2029). Authorize the Foundational Technology platform (head-end, network, data and billing integration) and an initial deployment consisting of

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[197]Response to CalAdv DR-002, Q5.b, Selected Vendor's "Pricing Clarifications," item 1 (May 12, 2025); [Confidential Information Begins]……………………………………………………………………..…………….. …… …… ……………………………………………………………………………………………………..……..... [Confidential Information Ends] [confidential].

[198]Response to CalAdv DR-002, Q5.b, Selected Vendor's "Pricing Clarifications," items 12, 15 and 38 [confidential].

[199]Response to CalAdv DR-002, Q5.b, RFP package, "Appendix PR – Key Terms for Products," § 2.3 [confidential].

(a) the replacement, with SM 2.0 devices, of SM 1.0 electric meters and gas modules as they fail once the platform is in service, and (b) the proactive replacement of electric meters in the capacitor-defect cohort, defined as the meters carrying capacitors from the date-code range the vendor identified, as validated by date code and serial range, and capped at the 403,401 such meters SDG&E reported in service on June 23, 2026, or the smaller number the validation supports,[200] together with the SM 1.0 gas modules in each mesh cell swept, to reduce the number of working modules orphaned when the electric meters through which they communicate are removed, and (c) replacement on request, for any customer who enrolls in a rate or program requiring 15-minute interval data or who asks for the new meter, at the failure-replacement unit cost, or remote reprogramming where the legacy network can carry it.

On SDG&E's own forecast, Phase 1 is on the order of 405,000 to 495,000 electric meters and 260,000 to 305,000 gas modules (about 125,000 failures and 135,000 to 180,000 co-located modules) and a loaded cost of about $280 to $312 million through 2029, of which about $147 to $177 million is device cost, the range reflecting whether the meters installed in 2012–2019 belong in the cohort (see Section IV.C);[201] the authorized amounts should be stated by category and year in the decision (see Section V and Attachment SG-5).[202] SDG&E's response to UCAN's pending request on the composition of the cohort will

[200] Response to CalAdv DR-005, Q28.g (497,381 meters installed; 403,401 in service as of June 23, 2026; none under warranty).

[201] Attachment SG-2, "Results," cohort-size block, and scenario C2, 2024–2029 totals.

[202] Attachment SG-2, sheet "C2-P1," electric volume row, places about 242,000 electric meters in 2028 and the balance of Phase 1 in 2029, assuming route-based work begins in the first year after the platform is in service; SDG&E's own plan installs about 132,000 meters in its first year and reaches mass deployment in the second (Ch. 3 Workpaper 1, note A30; Ex. SDG&E-04 at BB/DC/DH-8, lines 2–4 and 11–20). Profiling Phase 1 to SDG&E's first-year capability instead would move volume from 2028 into 2029 and change only the split of the authorized amounts between the two years, not the Phase 1 total or the checkpoint date.

determine where in that range the figure falls; I will update Attachment SG-2 on receipt, and UCAN will offer the updated attachment into the record.[203]

[Confidential Information Begins]…………………………………...……………………..

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[Confidential Information Ends]; the sequencing within Phase 1 should also be planned by mesh cell, with the SM 1.0 gas modules in each swept cell replaced with the meters, because removing SM 1.0 electric meters piecemeal thins the mesh through which the remaining meters and gas modules communicate,[Confidential Information Begins] [Confidential Information Ends][204]SDG&E plans to manage the same problem under its own schedule, by "deployment-sequencing adjustments" and, "where warranted," prioritized replacement of affected devices, at a cost it says is "included within the broader forecasts."[205]

Checkpoint (2029–2030). Require SDG&E to file an application by July 1, 2029, with Phase 1 data through the first quarter of 2029 and quarterly supplements until the record closes, reporting Phase 1 results and proposing Phase 2, so that parties have discovery and the Commission can decide before Phase 2 installations would begin in 2031. The decision should specify what the filing must contain, each item drawn from, or measurable against,

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[203] The high case uses the 389,211 flagged meters in service in SDG&E's forecast workbook (Attachment SG-2, "Results," cohort-size block); SDG&E's later count of 403,401 in service on June 23, 2026 (Response to CalAdv DR-005, Q28.g.ii) is about 14,000 higher, and the update will carry whichever population the validation supports.
[204] Response to CalAdv DR-002, Q5.b, Vendor 1 interview deck of June 18, 2025 (bid summary session), slide 37 (confidential).
[205] Response to SBUA/TURN DR-001, Q9 (Sept. 21, 2026), response to sub-part (d), labelled "(c)" in SDG&E's response.

SDG&E's own procurement, contract and forecasting documents so that none can be characterized as an intrusion on management:

1. Phase 1 recorded costs against the authorized amounts by category and year (see Section V and Attachment SG-5), and the unit cost per device installed against the contract price.

2. Monthly device failures since 2026 by class, capacitor cohort, date code and installation year; a re-forecast of the remaining SM 1.0 fleet with its inputs and model in native form; and a back-test of that re-forecast against the 2026–2029 actuals, which SDG&E has not performed for the gas forecast in the Application and does not claim for the electric.[206]

3. Transition metrics: installation rate and first-read success; the number of replacements on request; interval-data delivery against the service levels in the executed agreement [Confidential Information Begins]……..…………………………………………….. .... [Confidential Information Ends];[207] the count of SM 1.0 gas modules that lost communication when an electric meter was removed; estimated bills by cause; interval-read completeness by mesh cell; SM 1.0 network-mitigation spending; and the status of the SM 1.0 field area routers. SDG&E

[206] Response to UCAN DR-02, Q5.c (no formal back-test of the gas-module model); Response to CalAdv DR-004, Q1.f (forecast validation "may be a part of" SDG&E's annual update); see also Response to UCAN DR-02, Q1 (the hidden "Break and Replace" tab SDG&E removed from its workpapers on September 14, 2026 as incomplete internal draft material).

[207] Response to CalAdv DR-002, Q5.b, "Appendix PH Service Levels" (Selected Vendor response) [confidential].

does not track two of these, estimated bills by cause and orphaned gas modules, today,[208] and the decision should direct it to do so from the start of Phase 1.[209]

4. Vendor performance: SM 2.0 device failure rates against the excessive-failure thresholds in the executed agreement, there being none yet[210] [Confidential Information Begins]……………………………………………………………….. ………..……………………………………………………………………………… ……………………………….…. [Confidential Information Ends];[211] warranty claims made and paid; and the executed agreements with the incumbent for SM 1.0 device supply, head-end support and hosting through the end of the transition.

5. Benefits realization and forward plans: the NextGen capabilities in service and their measured use; interval data delivered to CCAs against the service levels; and the NextGen roadmap, the CCA data plan and the gas data plan described in Section VII, each reviewed by the technology advisory panel recommended there.

6. A Phase 2 proposal that prices at least two alternatives, continued failure-led replacement and a mass sweep of the remaining fleet, on a common present-value

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[208] Response to CalAdv DR-004, Q3.a (SDG&E "does not directly track or maintain data identifying the specific reason an individual bill is estimated"); Response to SBUA DR-003, Q2.c (SDG&E "does not maintain data that distinguishes between" a gas module that is non-communicating because of intrinsic failure and one orphaned by loss of communication with a nearby electric meter).

[209] Estimated bills and orphaned gas modules are the customer harms on which SDG&E's own testimony relies. Ex. SDG&E-02 at SB-12, lines 1–3, and SB-19, lines 13–15.

[210] Response to CalAdv DR-005, Q23.a ("There is currently no agreement.") and Q23.g; Response to UCAN DR-02, Q6.b.

[211] Response to CalAdv DR-002, Q5.b, Selected Vendor's "Response to SDGE Follow up Questions," item 15 [confidential].

basis from the re-forecast, with the revenue-requirement model produced with the filing.[212]

The decision should also state the default: until Phase 2 is authorized, replacement of failed SM 1.0 devices with SM 2.0 devices continues under the Phase 1 authorization, with the authorized amount for failure replacement extended at the same annual rate, so that the checkpoint delays nothing that must be done in any event and the review itself cannot be said to strand the program.

Phase 2. Authorize mass deployment of the remaining fleet only on the checkpoint record, with the Commission free to adopt Scenario C1, Scenario C2, or a variant sized to what Phase 1 shows.

Q. What is the cost impact of replacing the capacitor cohort proactively rather than as each meter fails?

Scenario C2 is Scenario B plus the sweep, so the cost of replacing the cohort in 2028–2029 rather than waiting for each meter to fail is the difference between the two: between $23 million and $36 million of present-value cost, depending on the failure path, including the gas modules replaced with the swept electric meters.[213]

Q. Why replace the capacitor cohort proactively rather than as each meter fails, given that the pure failure-led design costs less?

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[212] SDG&E "does not provide its revenue requirement model to external parties," Response to UCAN DR-02, Q11.a; a checkpoint whose arithmetic cannot be examined is not a checkpoint.

[213] Table 3 (Scenario C2 less Scenario B on each failure path).

A. The electric meters cohort with the known defect should be proactively replaced for four reasons:

First, these are meters that will fail anyway, soon. While SDG&E cautions that membership in the population does not itself establish causation;[214] the failure rate for this group of meters is pronounced: 4 to 8 percent a year and rising; so the sweep advances the replacement of meters by a few years that SDG&E's model forecasts will fail entirely by 2033–2035.[215]

Second, a meter that fails in service costs the customer something that a meter replaced on a route does not. SDG&E's own testimony describes the consequences of SM 1.0 device failures as "greater reliance on estimated bills, reduced access to timely usage information, and/or slower restoration during unplanned outages,"[216] reports about 400,000 estimated bills in the first eleven months of 2025,[217] a figure SDG&E has since restated as 314,336, about 1.2 percent of bills,[218] and attributes about 20 percent of 2025 billing complaints to

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[214] Response to CalAdv DR-005, Q28.g.iv (membership "does not establish causation, and such failures may have resulted from causes unrelated to the capacitor").

[215] Attachment SG-2, "Inputs," "SDG&E's electric failure forecast by capacitor flag" (UCAN arithmetic from the DR-004 workbook: SDG&E's expected failures and operating units summed over the flagged and unflagged district rows; every flagged row reaches zero by 2034, and the implied failure rate of the rest of the fleet rises from 3 percent in 2026 to 22 percent in 2035).

[216] Ex. SDG&E-02 at SB-12, lines 1–3.

[217] Ex. SDG&E-02 at SB-12, line 23, to SB-13, line 1. Two SDG&E series describe the trend. The annual series SDG&E produced to the CCAs shows 125,517 estimated bills in 2021 and 131,805 in 2022 (0.6 percent of bills), 242,172 in 2023 (1.2 percent) and 388,363 in 2024 (1.9 percent). Response to SDCP/CEA DR-001, Q8.a. The monthly workbook SDG&E produced to Cal Advocates, which excludes estimates later corrected, shows 146,911 estimated bills in 2022 (0.5 percent of bills), 208,794 in 2023 (0.7 percent), 319,552 in 2024 (1.1 percent) and 314,336 in January–November 2025 (1.2 percent), with the 2025 monthly count falling from 33,523 in January to 21,662 in November. Response to CalAdv DR-002, Q9.a, workbook "CalAdvocates_DR_021826_All Estimated Bills.xls," tab "Estimated Bills by Installation." On either series, 2025 ran level with or below 2024 rather than continuing to climb.

[218] Response to CalAdv DR-003, Q17 (the workbook produced with the Response to CalAdv DR-002, Q9.a, "does not include original estimates that have since been corrected by the billing team and no longer reflect an estimated bill"; it shows 314,336 estimated bills against 26,538,263 bills issued in January–November 2025, or 1.18 percent).

them, since restated as 16 percent through October.[219] A failed electric meter can also orphan the gas modules that communicate through it, so that working gas modules are counted as failed and their customers estimated as well.[220] Concentrating the proactive work on the one population where failure is predictable removes most of that harm at the lowest cost per customer protected.

Third, planned replacement is likely cheaper per meter than reactive replacement, at least where a contractor does the reactive work. A route-based sweep is priced in the model at SDG&E's own installation cost for mass deployment, [Confidential Information Begins]…….. [Confidential Information Ends] a failure-driven replacement is a single truck roll to a single address after the customer has already lost service, which SDG&E prices at $44 of labor for its own crews and $75 for a contractor,[221] and the model prices every failure-led installation on those terms (see Section IV.E).[222] Confining the proactive sweep to the cohort leaves about 307,000 electric meters and 628,000 gas modules to failure-led replacement in 2030–2033 on SDG&E's forecast, of which all but about 60,000 devices a year are priced at the contractor rate.[223]

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[219] Ex. SDG&E-02 at SB-13, lines 4–5; Response to CalAdv DR-003, Q18 (the 20 percent "included data pulled from January 1, 2025 – November 1, 2025, which was not reflective of the entire year and equals 16%. Given the approximation used, SDG&E rounded up to ~20% as its estimate through year-end.").

[220] Response to CalAdv DR-005, Q26.a.

[221] Attachment SG-2, "Inputs," unit costs[Confidential Information Begins]……………………………………..….. …... [Confidential Information Ends]; Ex. SDG&E-04 at BB/DC/DH-7, lines 6–7 (installation by a deployment vendor). Reactive work: Response to SBUA DR-003, Q8.e (2025 dollars, direct costs: $44 in-house and $75 contractor per electric meter, $27 and $47 per gas module; SDG&E has not yet used contractors for like-for-like replacements).

[222] Attachment SG-2, "Inputs," failure-led installation labor block, and each scenario sheet's "of which failure-led" rows and labor-adjustment rows. Pricing every installation at the mass-deployment cost instead would lower Scenario C2 by about $10 million on SDG&E's forecast ("Results," no-labor-split block); a 25 percent premium on every installation, sweeps included, is the outer bound (installation-premium block).

[223] Attachment SG-2, sheet "C2-P1," volume rows for 2030–2033 (electric 63,078, 74,073, 82,786 and 87,181; gas 156,887, 222,730, 209,724 and 39,018; the "of which failure-led" rows show that all of these are failure

Fourth, the sweep informs the Commission's checkpoint decision. A Phase 1 consisting only of scattered failure replacements would not test route-based deployment at all: unit cost per device installed, installations per crew-day, the vendor's delivery against the service levels and the excessive-failure thresholds are all metrics that need a deployment at scale to produce them. Roughly 400,000 to 500,000 cohort and failure replacements over two years is large enough to generate that evidence and small enough to stop if the evidence is bad; it is the same order of magnitude as the first two years of the Application's own schedule,[224] and SDG&E's own plan likewise begins with a smaller initial deployment for the "valuable insights" it yields,[225] which Phase 1 makes the authorized scope.

What proactive replacement of the cohort does not do is justify sweeping the other two-thirds of the fleet, which is failing at 1 to 3.5 percent a year with no identified defect.

Q. Has the Commission staged an authorization of this kind before?

A. Yes, for this very system. D.07-04-043 authorized SM 1.0 only after a separately settled pre-deployment phase funded at $9.3 million,[226] conditioned its approval on a further Commission step ("our approval is conditioned upon SDG&E filing its technology contracts stemming from its RFPs as Advice Letters, and subsequent Commission

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replacements). The gas modules are replaced on failure under Scenario C2 as they are under SDG&E's like-for-like practice today.

[224] Ch. 3 Workpaper 1, note A30 (132,363 electric meters in the first year and 388,681 in the second, about 521,000).

[225] Ex. SDG&E-04 at BB/DC/DH-8, lines 11–20 (an initial deployment of about 5 percent of the replacements "across different geographies and customer types," because "[t]he initial deployment will provide valuable insights for SDG&E prior to mass deployment"); Response to CalAdv DR-004, Q4.c.i ("a phased deployment (initial deployment in 2027; mass deployment beginning in 2028)").

[226] D.07-04-043, § 2.2 (D.05-08-028 authorized $3.4 million of pre-deployment work and $5.9 million of bridge funding).

certification that the contracts met the functionality criteria"),[227] required quarterly implementation reports to the Energy Division and an annual report from a technology advisory panel on which UCAN and the Division of Ratepayer Advocates sat,[228] and capped the balancing account at a stated amount.[229] The Commission's reasoning in the smart grid rulemaking points the same way: "the best estimates of rapidly changing technologies, capabilities and costs can be obtained close to the point of the implementation of a project that uses these technologies," so that "an assessment of the reasonableness of a project cannot be made accurately" far in advance.[230]

Relevant here is that D.07-04-043 considered and declined a partial roll-out to one climate zone because it "does not significantly improve cost-effectiveness."[231] However, that was a proposal to build less, permanently; what I recommend is a staged authorization of the same program, which is what the Commission in fact imposed in 2007 through the contract certification, and what its checkpoint rationale in D.10-06-047 supports.

Q. Does the phased design impair SDG&E's operations during the transition?

A. No more than SDG&E's own schedule does, and the record answers each concern SDG&E has raised. SDG&E's general objection, that a hybrid approach duplicates system costs and prolongs support for aging technology, is unquantified, and those are the continuation costs Section IV.E tests at two and three times SDG&E's figures;[232] its own account of a

[227] D.07-04-043, § 6.1.2 and Ordering Paragraphs 1–2.
[228] D.07-04-043, § 4 and Ordering Paragraph 3.
[229] D.07-04-043, Ordering Paragraph 5.
[230] D.10-06-047, Findings of Fact 12–13.
[231] D.07-04-043, § 9.1 and Finding of Fact 31.
[232] Response to CalAdv DR-002, Q3.a(ii) (a hybrid approach "would result in duplicative costs to operate and maintain two disparate systems and associated infrastructure"); Response to CalAdv DR-006, Q58.c (extending the legacy environment "would require continued mitigation activities and support for aging technology, increasing

degrading network in 2030–2032 applies with more force to the phased design and is answered the same way.[233]

Regarding mesh network performance concerns: SDG&E's testimony explains that the SM 1.0 field network "depends on a dense population of functioning meters," that it "cannot reroute communications if too many electric meters are missing," and that gas modules reach it through a nearby electric meter, as many as ten modules to one meter.[234] That is a property of every scenario, including the Application, which in its third year (2029 as filed, 2030 shifted for a 2027 decision) removes about 654,000 electric meters while about 400,000 SM 1.0 gas modules are being exchanged.[235] [Confidential Information Begins] ....[Confidential Information Ends][236] and it says it will manage mesh integrity during its own transition by "network analysis, field investigation, deployment-sequencing adjustments, and communications-equipment enhancements," at a cost "included within the broader forecasts."[237] Phase 1 applies the same method deliberately: because a gas module

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operational complexity and prolonging reliance on infrastructure approaching end of support"). Neither response quantifies the cost, and SDG&E "has not prepared, and is not aware of, any separate comprehensive quantitative cost analysis comparing alternative deployment timing, deployment sequencing, deployment phasing, or sourcing strategies." Response to UCAN DR-02, Q3 and Q6.a; Response to CalAdv DR-005, Q22.b.

[233] Ex. SDG&E-03 at DT/BB-38, lines 14–20 (under SDG&E's own schedule, sustaining the network in 2030–2032 "will require more devices, truck rolls, and labor hours," and "[b]illing estimations and exceptions will become more frequent"). The phased design leaves more SM 1.0 meters in service in those years (Attachment SG-2, sheet "C2-P1," SM 1.0 in-service row: 1,079,047 electric meters at the end of 2030 on SDG&E's forecast); the added devices, truck rolls, labor and estimated bills are the SM 1.0 continuation costs Section IV.E carries and tests at two and three times SDG&E's figures.

[234] Ex. SDG&E-02 at SB-17, lines 17–22; SB-18, lines 5–12; and SB-19, lines 4–7.

[235] Attachment SG-2, sheet "A," volume rows (Ch. 3 Workpaper 1, notes A29–A30, shifted one year).

[236] Response to CalAdv DR-002, Q5.b, RFP package, "Appendix N1" § 5.1.2 [confidential].

[237] Response to SBUA/TURN DR-001, Q9 (Sept. 21, 2026), response to sub-part (d), labelled "(c)" in SDG&E's response.

communicates through a nearby SM 1.0 electric meter, not necessarily its own premise's,[238] the sweep proceeds by mesh cell with all SM 1.0 gas modules in the cell exchanged with the meters, which Attachment SG-2 prices by a premise-level proxy as about 180,000 modules on SDG&E's forecast, added to Phase 1 and removed from the later years.[239]

Second, regarding end date implications: Scenarios B and C2 finish in 2035 because December 31, 2035 is the date through which the incumbent has said it can support the RFLAN network, under a post-2028 agreement not yet negotiated,[240] and beyond which SDG&E does not expect vendor support for the network, its meters or the OpenWay head-end,[241] its field area routers were bought in 2018 with ten-year warranties and 4G radios that SDG&E does not expect to be upgraded,[242] and the operating system beneath the on-premises head-end leaves extended support in October 2031.[243] The model carries the cost of a cloud-hosted SM 1.0 head-end for the years after 2031 (see Section IV.E);[244]

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[238] Ex. SDG&E-02 at SB-2, n.2 (gas modules "connect through nearby electric meters using Zigbee protocol communication technology"), and SB-19, lines 6–7 ("as many as ten gas modules may connect to a single electric meter").
[239] Attachment SG-2, "Inputs" (co-located gas module lever, set at the share of electric premises with a gas module) and scenario sheets C1 and C2, gas volume rows.
[240] Response to UCAN DR-02, Q10.a–b (the incumbent's continued maintenance of the RFLAN network through December 31, 2035 was contingent on a future maintenance-and-support agreement for the period beyond 2028, on pricing and terms to be mutually agreed; SDG&E "did not receive an unconditional, binding commitment for continued supply of Smart Meter 1.0 devices or continued support of the Smart Meter 1.0 ecosystem beyond existing contractual commitments") and Q9.a (SDG&E holds no offer, term sheet or draft agreement); Response to CalAdv DR-002, Q5.i and notes 6 and 8. What the phased design needs from the incumbent after 2028 is that network and head-end support, not device supply, because SM 1.0 devices that fail after 2028 are replaced with SM 2.0 devices; the model carries the cost of the support for every year of the overlap (see Section IV.E), and the executed agreement is a checkpoint item (item 4 above).
[241] Ex. SDG&E-01 at DG-10, lines 11–16; Response to CalAdv DR-003, Q13.c ("Beyond 2035, vendor support for RFLAN, associated meters, and OpenWay head-end components is not expected to continue.").
[242] Ex. SDG&E-02 at SB-18, lines 13–19, and SB-19, lines 1–3.
[243] Response to UCAN DR-02, Q9.e.
[244] Ch. 3 Workpaper 3, tab "Updated IT Assumption," as served December 18, 2025 and removed by SDG&E's notice of September 14, 2026 as "incomplete internal draft material" that "does not reflect SDG&E's finalized analysis" (Response to UCAN DR-02, Q1). [Confidential Information Begins]……………………………..
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SDG&E's own dual-head-end table notes that the SM 1.0 head-end "would likely need another upgrade if decommissioning in 2031 is postponed,"[245] and SDG&E has since called that upgrade a version upgrade it has not priced, for which the cloud-hosted path is the model's proxy.[246] The model does not carry a line for replacing the field area routers or migrating their backhaul, because SDG&E's own transition estimate carries none: its network-mitigation capital runs at $0.8 to $1.2 million a year through 2030 and falls to zero in 2031,[247] and UCAN has asked SDG&E for its plan and cost for the routers through 2035.[248] SDG&E's carriers have told it a 4G sunset is likely in 2034–2035, the transition's last two years, when the routers or their backhaul would need attention.[249] Any figure SDG&E supplies belongs in the continuation-cost sensitivity in Section IV.E, which holds on SDG&E's forecast up to about 1.4 times SDG&E's continuation costs and on the actuals trend at three times.[250]

Third, regarding the running of two parallel systems: SDG&E plans to keep the SM 1.0 head-end and its integrations "in service and run in parallel with the new SM 2.0 systems,

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… .... [Confidential Information Ends]

245 Response to CalAdv DR-005, Q22.a, table, line 4 note.

246 Response to UCAN DR-02, Q9.e (the supported head-end versions run only on Windows Server 2022; SDG&E "has not estimated the incremental annual cost of extending the Smart Meter 1.0 / Smart Meter 2.0 dual head-end overlap period by one, two, or three years beyond 2031"). A figure SDG&E supplies can replace the proxy.

247 Response to SBUA/TURN DR-001, Q9.a (Sept. 21, 2026), table.

248 UCAN-SDG&E-DR-03, Q2.f.

249 Response to CalAdv DR-003, Q7.e–f (April 7, 2026 supplement) (SDG&E has no carrier notice; its carriers have said verbally that a sunset "is likely to occur in the 2034/2035 timeframe"; SDG&E "is not aware of any evidence indicating that FARs deployed to-date require replacement prior to the end of their expected 10-year life"); Q5.e (the network-mitigation estimate falls to zero in 2031 because SDG&E's schedule retires the mesh in that year, not because the routers are expected to outlast it).

250 Attachment SG-2, "Results," continuation-cost block: at twice SDG&E's continuation costs Scenario C2 is about $17 million above Scenario A on SDG&E's forecast and about $63 million below on the actuals trend; at three times it is about $46 million above on SDG&E's forecast and about $34 million below on the actuals trend. Until SDG&E supplies a figure, that doubling and tripling is the placeholder for a backhaul migration in 2034–2035.

until all SM 1.0 electric meters and gas modules are fully replaced,"[251] under every schedule; the question is only for how long. SDG&E's own figure for the overlap is $1.8 to $2.1 million a year of IT cost, not yet negotiated for 2028–2030; "[n]o changes are needed to the existing 1.0 HES in order to support dual head-ends," and SDG&E did not evaluate "a longer period of operating two head-end systems in parallel."[252] Those costs are in the model for every year the two systems overlap. SDG&E's fuller IT table carries a further line mixing retiring and persistent systems, whose SM 1.0 share lies within the $7 to $14 million a year the Section IV.E sensitivity adds.[253]

Third, on workforce capacity: SDG&E states that it "can replace approximately 60,000 devices per year, insufficient to keep pace with projected failures."[254] That describes today's meter shop exchanging failed devices for legacy devices, not a deployment program. SDG&E's meter shop replaced about 74,000 devices in 2025, with contractors for volumes materially above that capacity;[255] under Scenario C2 the failures of 2030–2033, well above it on SDG&E's forecast,[256] are replaced with SM 2.0 devices by the

[251] Ex. SDG&E-03 at DT/BB-13, lines 13–16.
[252] Response to CalAdv DR-005, Q22.a ("The Operating cost category for SM 1.0 includes only IT operating costs"; table, line 1 note; line 2 note, "Business costs for operating the HES were not able to be broken out and were not included"; line 3 note, "Current maintenance contract ends in 2028. Maintenance costs for 2028 - 2030 have not been negotiated, so only a standard escalation has been applied.") and Q22.b.
[253] Response to SBUA/TURN DR-001, Q9.a (Sept. 21, 2026), table, "SM 1.0 IT support - All Other smart meter Systems" ($2.4 to $7.1 million a year of capital for 2026 through 2031: 3,330; 5,928; 7,126; 3,724; 4,521; and 2,419 thousand dollars), with the notes that "these costs include all systems other than the HES," that the table covers "both Smart Meter 1.0 systems (To Be Retired) as well as Persistent Smart Meter Systems," which SDG&E could not separate, and that MDMS-specific support costs "were not able to be broken out from this total." The model's continuation costs are about $6.9 million a year unloaded (see Section IV.E), so testing them at two and three times SDG&E's figures adds about $7 and $14 million a year.
[254] Ex. SDG&E-03 at DT/BB-38, lines 4–8.
[255] Response to CalAdv DR-006, Q58.a–b, and Response to CalAdv DR-002, Q8.a (46,457 electric meters and 27,196 gas modules in 2025); Response to SBUA DR-003, Q8.e (contractors for like-for-like exchanges "when meter or module failure volumes materially exceeds the capacity of its existing internal workforce").
[256] Attachment SG-2, sheet "C2-P1," volume rows (about 60,000 electric meters and 160,000 to 220,000 gas modules a year in 2030–2032).

deployment contractor Phase 1 has already stood up, and the largest year of the program, about 450,000 to 495,000 electric meters in each of 2034 and 2035 on SDG&E's forecast, depending on the cohort size, is below the Application's own single-year peak of about 654,000 in its third year.[257]

What the phased design changes is not SDG&E's ability to operate the system but the date on which working meters are retired, and that is the decision D.24-12-074 asked SDG&E to justify, while counting "expediting the transition to Smart Meter 2.0 most cost-effectively" among the cost reductions, which the phased design does for the platform and the cohort.[258]

Q. What do the customers whose SM 1.0 meters keep working, and the CCAs that serve them, forgo while they wait?

A. One capability, interval granularity, and for a bounded time. On SDG&E's forecast, Scenario C2 leaves about 1.1 million SM 1.0 electric meters in service at the end of 2029 and about 900,000 at the end of 2033, all replaced by 2035; the Application finishes in 2031. The customers affected are therefore those whose meters keep working and lie outside the capacitor cohort, and their wait is one to four years beyond the Application's own four-year sequence.[259] What such a customer does without is 15-minute, two-channel interval data: SDG&E's sample residential SM 1.0 interval file is 60-minute single-channel,[260] every SM 2.0 meter records 15-minute two-channel data as part of the

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[257] Attachment SG-2, sheets "A" and "C2-P1," electric volume rows.
[258] D.24-12-074 at 673–674.
[259] Attachment SG-2, sheets "A" and "C2-P1," SM 1.0 in-service rows.
[260] Response to SD CCAs DR-003, Q9.c (sample interval files from the production data flow).

Foundational scope,[261] and SDG&E says the legacy system "cannot provide" that granularity "at scale."[262] For a customer with solar, an electric vehicle or an interest in the sub-hourly rates the Commission has been considering,[263] that is a real difference, and it is why Phase 1 should include replacement on request, discussed below. The number of customers who wait may also be smaller than the count of meters: UCAN has asked SDG&E, in a pending data request, to identify which elements of the legacy system limit 15-minute collection at scale, how many SM 1.0 meters the system could carry at 15-minute intervals today, and whether that number rises as the Phase 1 replacements remove meters from the system;[264] to the extent it does, the remote reprogramming recommended for Phase 1 below could reach those customers without a meter change.

The other customer-facing capabilities do not differ between the two schedules. Local real-time data has been unavailable to SM 1.0 customers since ZigBee support ended in 2023 (see Section VII.A), and the Application does not propose to open the new meter's Wi-Fi interface, so a customer on either meter obtains it only if the Commission adopts the condition in Section VII.A. Customer Insights is an opt-in NextGen service for which SDG&E "has not determined whether a fee will be charged."[265] Remote connect and disconnect, outage and restoration notification and accurate billing all exist on SM 1.0 and

[261] Response to UCAN DR-02, Q17.
[262] Ex. SDG&E-03 at DT/BB-26, lines 1–2.
[263] Ex. SDG&E-03 at DT/BB-25, lines 11–19 (citing D.25-08-049 and D.22-12-056).
[264] UCAN-SDG&E-DR-03, Q28 (served September 25, 2026; responses requested by October 9, 2026): the elements of the SM 1.0 system that limit 15-minute collection and their current utilization; whether SM 1.0 meters can be reprogrammed remotely and how many are; how many meters the system could carry at 15-minute intervals today; whether that number rises as SM 1.0 meters are removed, and which limits are freed by removals and which are not; and the cost per meter.
[265] Response to SDCP/CEA DR-001, Q18.c–d.

are lost when the meter or its communication path fails,[266] which under Scenario C2 is the moment the meter is replaced. Gas customers forgo no data capability, because SDG&E proposes no change in gas interval delivery under SM 2.0; what they bear is the estimated bill between a module's failure or orphaning and its replacement, described above.[267] The grid-side NextGen capabilities accrue meter by meter under any schedule, and so do the subscription and connectivity charges that pay for them.

For the CCAs the answer is narrower than the concern. SDG&E "does not anticipate any changes to CCA meter data access as a result of the SM 1.0 to SM 2.0 transition" and "does not propose any changes to the manner of CCAs' receipt of customer usage data": interval data will continue to flow from the head-end through the meter-data-management and billing systems to the CCA data lake, available "within 24-48 hours of power flow," and a feed direct from the meters to a CCA is, in SDG&E's word, "theoretical."[268] A phased deployment therefore delays no improvement in CCA data access, because none is proposed. What it does is leave each CCA with hourly data for some customers and 15-minute data for others for longer than the Application would, which complicates rate design on sub-hourly prices, settlement and load forecasting, and program measurement. The Application produces the same mixed condition for 2028–2031; Scenario C2 extends it for the customers whose meters last. Against that, the CCAs' customers pay the lower distribution revenue requirement of the phased design, and the data conditions in Section VII.A take effect on the same day under either schedule.

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[266] Ex. SDG&E-02 at SB-16, lines 1–23, and SB-17, lines 1–8.
[267] Response to UCAN DR-02, Q19.
[268] Response to SDCP/CEA DR-001, Q5.a–b and Q26.b; Response to SDCP/CEA DR-002, Q2.7.

To remove the one real disadvantage at its source, Phase 1 should include replacement on request: a customer who enrolls in a rate or program that requires 15-minute data, or who asks for the new meter, receives one, at the failure-replacement unit cost, with the count reported at the checkpoint, or is reprogrammed remotely where the legacy network's limited capacity allows.[269] Provisioning by customer need is already SDG&E's practice: its SM 1.0 system can reprogram meters remotely from 60- to 15-minute intervals,[270] and some residential SM 1.0 customers receive 15-minute two-channel data today;[271] the volume would be small against a Phase 1 of 400,000 to 500,000 meters; and every meter installed that way is one a customer wanted, the opposite of the stranded-asset problem the phased design exists to avoid.

Q. Should the NextGen capabilities, and the recurring charges that come with them, be pre-approved with Phase 1?

A. No. The NextGen capabilities and their recurring charges should be decided at the checkpoint, for the reasons set out in Section VII.B: SDG&E proposes to enable only two of the capabilities the platform it is buying supports, the benefit case for those two rests on planning estimates rather than on operating data, and SDG&E itself notes that "the Commission could elect to approve these NextGen capabilities at a later point," while urging approval now.[272] Deferring the decision to the checkpoint reduces ratepayers'

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[269] Response to SDCP/CEA DR-001, Q4.b (the legacy network "is limited on the amount of data it can send to back-office systems").
[270] Response to CalAdv DR-003, Q13.d ("SM 1.0 Remote Meter Change," an interface "to reprogram electric meters from 60 to 15-minute interval data").
[271] Response to SD CCAs DR-003, Q9.c.
[272] Ex. SDG&E-07-2E at NR/DT/MW-29, lines 17–20 ("While the Commission could elect to approve these NextGen capabilities at a later point, rather than as part of the SM 2.0 solution approved in the instant proceeding, SDG&E submits that given the benefits of the NextGen capabilities identified in the Application, approval at this time is warranted and would serve the public interest.").

present-value cost by about $10 million (see Section IV.E), while the capabilities and their recurring charges amount to roughly ten times that, and the checkpoint is where a roadmap and a benefit record built during Phase 1 will exist to decide them on.

Q. Why not simply deny the Application, as D.24-12-074 did?

A. Because the record now supports a defined, bounded authorization, and because the alternative of a second denial would leave SDG&E to continue replacing failed devices with legacy devices that, by SDG&E's own account, "cannot be reliably operated, communicated with, or maintained" after 2035 and would be retired with five to eight years of life remaining.[273] The platform is needed under every scenario, including SDG&E's delay scenario; the capacitor cohort is a demonstrated defect; and the failures are real even if their trajectory is not. What the record does not support is the commitment of the remaining two-thirds of the fleet on a schedule that no analysis has tested. The phased authorization gives SDG&E what it needs to begin and gives the Commission what D.24-12-074 said it needed before authorizing the rest.

Q. Does a phased authorization conflict with the Commission's practice on pre-approval of capital projects?

A. No; it applies it. Regulators that commit ratepayer dollars before a project is built are advised to grant pre-approval "only upon a supported showing that regulatory action will benefit customers," to require the applicant "to explain why other options were rejected (and not simply why the applicant's option is appropriate)," to recognize that "approval of

[273] Response to CalAdv DR-003, Q12.b.

an option as a 'prudent' choice is not the same thing as approving the inclusion in rates of whatever dollars are expended to pursue it," to limit approvals to specified investments with "an express dollar amount,"[274] and to pair pre-approval with periodic review so as "to reduce the amount of investment at risk of nonrecovery."[275] A Commission that declares the risk allocation up front, authorizes a defined first phase, and reviews before committing the rest is doing what that guidance describes.

V. COST RECOVERY DESIGN

A. The proposed balancing account

Q. What does SDG&E propose?

A. A two-way, interest-bearing Advanced Metering Infrastructure Balancing Account (AMIBA) into which all SM 2.0 costs recorded since January 1, 2024 would be transferred on approval, with annual over- or under-collections addressed through Tier 2 advice letters, and a rationale that the account "allows the utility to track actual costs to an amount authorized for recovery by the CPUC, thereby ensuring that customers are charged for actual costs and refunded any overcollections. In turn, the utility does not make or lose money due to uncertainties in the scope of work."[276]

Q. What has discovery established about the proposal?

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[274] Scott Hempling & Scott H. Strauss, *Pre-Approval Commitments: When and Under What Conditions Should Regulators Commit Ratepayer Dollars to Utility-Proposed Capital Projects?* (NRRI 08-12, Nov. 2008) at ii–iii, 19–22 and 31–32.
[275] Scott Hempling, *Regulating Public Utility Performance: The Law of Market Structure, Pricing and Jurisdiction* (2d ed. 2021) at 295.
[276] Ex. SDG&E-06 at CWB-10, lines 15–16, and CWB-11, lines 6–9.

A. Five things. The Application states its request by year, by category and as an illustrative revenue requirement (Tables 6-2, 3-1 and 6-4), but not which of these is the "amount authorized for recovery" or what happens when actual costs exceed it; asked how it is defined, SDG&E answered that "the authorized revenue approved in this application would offset the actual revenue requirement spent for this project within the balancing account" and that any annual balance "would be evaluated to determine if [it] can be returned or collected from the ratepayers or carried over."[277] SDG&E did not evaluate a one-way account, milestone gating or shareholder cost sharing,[278] and asked what amount a one-way account would place at shareholder risk, it "has not calculated the requested estimate."[279] No stand-alone periodic report is proposed; SDG&E points instead to "balancing account review, and reasonableness review as applicable," and identifies no trigger for the latter.[280] No protection is proposed against early retirement of SM 2.0 assets.[281] And SDG&E had recorded $36.26 million of program costs through August 2026 with no executed agreement with the Selected Vendor [Confidential Information Begins] ....[Confidential Information Ends],[282] which it sought to sign by the end of 2026 and for which it now has no "definitive execution date,"[283] in any event after intervenor and rebuttal testimony.[284] The cost estimates themselves, SDG&E's "best

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[277] Response to UCAN DR-02, Q14.a.
[278] Id., Q14.b.
[279] Response to SBUA/TURN DR-001, Q14.c (Sept. 21, 2026).
[280] Response to UCAN DR-02, Q14.c.
[281] Response to UCAN DR-02, Q13.a.
[282] Response to UCAN DR-02, Q20 ($36.26 million recorded; "SDG&E has not executed a final agreement with the proposed vendor"); [Confidential Information Begins]…………………………………………………………………… … ....[Confidential Information Ends]
[283] Response to UCAN DR-02, Q20.c (Sept. 18, 2026) ("SDG&E has not established a definitive execution date").
[284] Response to CalAdv DR-005, Q23.g ("SDG&E seeks to complete its contractual negotiations by the end of 2026").

estimate" from non-binding RFP responses and internal expert estimates, are "not based on signed contracts or binding bids" and carry no estimate classification or ranges.[285]

Q. What is wrong with the rationale that the utility "does not make or lose money due to uncertainties in the scope of work"?

A. It describes the problem as if it were the solution. Replacing a metering system to maintain service is obligatory performance, not a voluntary undertaking that has to be induced; the utility is entitled to recover the reasonable cost of doing it and a normal return, and it bears the ordinary risk of doing it well or badly. A two-way account against an undefined authorized amount removes that risk entirely: whatever the scope turns out to cost, ratepayers pay, and the only review SDG&E identifies is the annual advice letter. That is the most permissive form of pre-approval, "pre-approval of all prudent costs, unknown at the time of the approval, but whatever they may be," and it shifts to ratepayers the risk that the program's scope, schedule and unit costs, none of which is under contract, will change.[286] A utility that seeks to be held harmless against "uncertainties in the scope of work" should, at minimum, be asked to define the scope.

The mismatch is compounded by the AMIBA's treatment of the memorandum-account balance. SDG&E proposes to recover "the CPUC revenue requirement for the years 2024 through the current year in rates, beginning January 1 following a decision," with no amortization period;[287] read as written, its illustration places $84.8 million, the 2024

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[285] Response to SBUA DR-003, Q4(a)–(b) (SDG&E "did not create or maintain such ranges" and "does not assign an AACE International estimate class").
[286] Scott Hempling, *Riders, Trackers, Surcharges, Pre-Approvals and Decoupling: How Do They Affect the Cost of Equity?* at 10–11 (six forms of pre-approval).
[287] Ex. SDG&E-06 at CWB-7, lines 12–13.

through 2028 revenue requirements, into rates "beginning January 1, 2028," of which about $20.5 million is the net revenue requirement for 2024 through 2027 and the remainder is the 2028 revenue requirement itself.[288]

Regulation's "major contribution" to efficient performance "can only be the providing of incentives—or taking care not to remove incentives—for private managements to exert themselves continuously in this direction,"[289] and the ordinary incentive is that utilities "receive no guaranty of their ability to enjoy a 'fair rate of return,' with the result that they may be under more or less severe pressure to practice operating economies."[290] Where "regulation goes too far in an attempt to supply this security, there arises the serious danger of a loss of managerial incentive toward efficient operation."[291]

A two-way account that recovers "actual costs" against an undefined authorization is the conception of regulation that lets a utility "cover [its] authorized revenue requirements—not more and not less—rather than treat [it] as [it] would be treated by a competitive market,"[292] and it does so for a program whose scope, schedule and unit costs are still within SDG&E's control.

Q. What do you recommend?

A. A one-way account for both phases, with defined obligations: recovery through the account capped at the authorized amounts, underspending against those amounts returned to

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[288] Ex. SDG&E-06 at CWB-7, note 14 ("if a decision is issued in 2027, SDG&E will recover $84.8M, which reflects the 2024 through 2028 CPUC revenue requirements, beginning January 1, 2028"); the 2024–2027 balance is the sum of the CPUC-gas and CPUC-electric rows of Table 6-4 for those years.
[289] Alfred E. Kahn, *The Economics of Regulation: Principles and Institutions*, Vol. 1 (Wiley 1970) (Kahn) at 32.
[290] James C. Bonbright, *Principles of Public Utility Rates* (Columbia Univ. Press 1961) (Bonbright) at 53.
[291] Bonbright at 64.
[292] Kahn at 120.

ratepayers, costs above them recoverable only by application, and, for Phase 2, a sharing band above the cap. The elements are these:

1. *Authorized amounts by category and year.* The decision should state the authorized amounts for Foundational Technology and for Phase 1 devices, by year, as the cap on recovery through the account. The amounts should be built from SDG&E's own unit costs, contract prices and program series applied to the authorized scope, so that the cap holds SDG&E to the estimate on which it asked to be authorized; on SDG&E's forecast they total about $280 to $312 million through 2029, depending on the size of the capacitor cohort (see Section IV.F), and Attachment SG-2 shows the calculation by category and year.[293] Any correction the Commission makes to SDG&E's figures in this proceeding, including the allocation factors in Section VI and the exclusion of NextGen from the Phase 1 scope, should be carried into the amounts before they are adopted.

2. *Overruns by application.* Recovery of costs above an authorized amount should require an application with a reasonableness showing, not a Tier 2 advice letter. A cap that can be raised by advice letter is not a cap; it is a floor.

3. *Sharing above the cap for Phase 2.* When the Commission authorizes Phase 2, costs above the Phase 2 authorized amount should be shared between shareholders and ratepayers according to a stated percentage, in the manner of the cost cap and sharing

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[293] Attachment SG-2, "Results," cohort-size block (loaded cost 2024–2029, Scenario C2 on SDG&E's forecast: $311.6 million with the cohort as SDG&E flags it and $279.7 million excluding the flagged meters installed 2012–2019), built from the unit costs, program series and escalation rates in SDG&E's Chapter 3 workpapers; see Section IV.F.

provisions the Commission adopted for SM 1.0 in D.07-04-043. There, expenditures up to $572 million were "deemed reasonable"; "90% of up to the first $50 million in Project costs exceeding $572 million" were recoverable "and 10% will be borne by SDG&E shareholders"; costs "above $622 million may be recoverable in rates following a reasonableness review by the Commission"; the mechanism was symmetrical, with a ten percent shareholder reward on the first $50 million of underspending; and the balancing account itself was capped, by ordering paragraph, at $617 million.[294] For Phase 2 I recommend the cap, the sharing band above it and the reasonableness review beyond the band, but not the shareholder reward on underspending: the account remains one-way, so underspending against an authorized amount built from SDG&E's own unit costs and contract prices is returned to ratepayers, and sharing applies only to the overrun. The present Application proposes the same account name with no cap, no sharing and no statement of how the authorized amount binds.

4. *Three-year amortization of the memorandum-account balance.* The balance accumulated from January 1, 2024 to the effective date of the decision should be amortized over three years rather than at a single rate change, if that is what SDG&E intends, for rate stability and because the $36.26 million recorded before any vendor contract existed is precisely the "preliminary" spending that should be recovered on defined terms.[295]

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[294] D.07-04-043, § 4 (settlement terms) and Ordering Paragraphs 5–6 (AMIBA capped at $617 million; Reward and Penalties Balancing Account capped at $5 million); the settlement was among SDG&E, the Division of Ratepayer Advocates and UCAN.
[295] Response to UCAN DR-02, Q20.a.

5. *Annual report.* SDG&E should file an annual report on spend against authorized amounts, devices installed, unit costs against contract, vendor performance against the service levels, failure rates, and the memorandum-account and balancing-account balances.

6. *Recurring charges beyond the authorized period excluded. SDG&E says post-2031 charges belong in a future rate case but would keep the AMIBA open until the program is absorbed into base rates;*[296] no charge for service beyond the period the authorized amounts cover should be recorded to the balancing account (Subsection B). For the Application as filed that period ends on December 31, 2031, the last year of service the prepayments booked in 2027 pay for; under a phased deployment, the Commission would set the corresponding date for Phase 2 when it authorizes Phase 2, so the line moves with the authorization, not with the calendar. On either side of it, the charges that fall outside the authorized amounts are forecast items for a general rate case.

Q. Why exclude the recurring charges beyond the authorized period from the balancing account?

A. Because balancing and memorandum accounts exist for costs that are large and unanticipated, and those charges are neither. SDG&E's own workbooks compute them month by month through 2044 (Subsection B). A cost that the utility has already forecast

[296] Response to UCAN DR-02, Q15.a (post-2031 operations "would be addressed in a future GRC or other appropriate regulatory proceeding, as applicable"); Ex. SDG&E-06 at CWB-11, lines 11–14 (the AMIBA to remain open until the program's costs are "incorporated into SDG&E's base business").

is a general rate case forecast item; recording it to a balancing account would convert a forecast the Commission can test into a pass-through it cannot.

B. The recurring charges outside the Application

Q. What recurring charges does the SM 2.0 platform entail?

A. Three kinds, all priced by the vendors per endpoint per month or as periodic subscriptions: meter-to-cloud connectivity for every SM 2.0 device (the cellular carrier charges), the head-end software-as-a-service fees (base fees for five environments plus a per-endpoint charge), and the NextGen capability subscriptions (analytics, grid applications, security certificates and the Customer Insights platform). For the connectivity charges, SDG&E confirms that "all costs are recurring."[297]

Q. How much of those charges is in the Application?

A. Only the five-year prepayments booked in 2027: [Confidential Information Begins] .... [Confidential Information Ends], $62.8 million in all, capitalized as five-year assets.[298] SDG&E states that the prepayments cover service only through 2031 and that post-2031 operations "would be addressed in a future GRC or other appropriate regulatory proceeding, as applicable."[299] [Confidential Information Begins]……………………………………………………………………………………… ……………………………………………………………………………………………… .... [Confidential Information Ends]

[297] Response to SBUA DR-002, Q4.a.
[298] Ch. 3 Workpaper 2, tabs "WP 3.4.5-C," "WP 3.4.6-C," "WP 3.5.5-C," "WP 3.5.6-C" [confidential].
[299] Responses to UCAN DR-02, Q12.c and Q15.a.

Q. What do SDG&E's own workbooks show for the full life-cycle?

A. The two cost workbooks SDG&E produced in September 2026 compute the charges through 2044. Attachment SG-4 tabulates them: connectivity of $242.9 million (foundational tier $138.3 million; NextGen increment $104.5 million), head-end fees of $124.7 million [Confidential Information Begins] .... [Confidential Information Ends], capability subscriptions of $28.6 million and Customer Insights platform fees of $29.8 million, a total of $425.9 million, of which $66.9 million falls in 2027–2031 and $359.0 million in 2032–2044.[300] Apart from $28.9 million of 2032–2045 Customer Insights costs that SDG&E includes in its NextGen cost-benefit analysis but does not request,[301] none of the post-2031 amount appears in the testimony, in Table 6-4, or in the delay comparison, and the life-cycle total is 6.8 times the amount requested.

Q. Why does this matter for the Commission's decision?

A. For two reasons. It is the largest single omission from the cost the Commission is asked to evaluate: a program presented as $825 million entails a further $359 million of vendor charges over the following thirteen years on SDG&E's own numbers. It changes the comparison between the Application and its alternatives, because the charges scale with

[300] Attachment SG-4, "Life-cycle," tabulating the workbooks produced in response to CalAdv DR-002, Q1.b: "MTC_Cost_Calculation_CONFIDENTIAL.xlsx" (rows 11–13) and "AMI_Software_Foundational_NextGen_Calculation_CONFIDENTIAL.xlsx" (Headend rows 43 and 84; Capability rows 42 and 102) [confidential].

[301] Ex. SDG&E-07-2E at NR/DT/MW-25, lines 3–5 and Table IV-2 ("Costs projected to be incurred in the years 2032-2045 are included in the 20-year CBA analysis; however, SDG&E is not requesting funding for those costs as part of this proceeding."). [Confidential Information Begins]…………………………………………………………..
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… .... [Confidential Information Ends].

endpoints in service and begin the month a device is installed, so a program that installs 1.6 million meters two to four years earlier incurs them two to four years earlier.

Q. How should the prepayments be treated for ratemaking?

A. As operating expense in the year the service is received. SDG&E books the prepayments as five-year capital assets that earn a return, so that ratepayers pay 1.23 dollars of revenue requirement for every dollar of subscription rather than 1.03;[302] on the $62.8 million in the Application that is about $12 million of additional revenue requirement in nominal terms (about $3 million in present value), and if every prepayment through 2044 is capitalized the same way, about $84 million (about $12 million in present value).[303]

A subscription to a hosted service is a purchase of service, and paying five years in advance to obtain a vendor discount does not change what is bought. SDG&E's own capitalization policy capitalizes "new additions of plant, property and equipment that have a useful life of more than one year," sets its capitalization thresholds for three things, general plant, substantial additions or betterments to existing plant, and computer software, admits software only where it "meets both the requirements of FASB ASC 350-40 and a threshold of $500,000," and expenses "[c]osts incurred to operate, maintain, or repair an asset so that the asset remains useful during its expected life."[304] While I am not a certified public

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302 Attachment SG-2, "Reconciliation" (revenue requirement per loaded dollar by asset class).
303 Attachment SG-4, "Life-cycle," capitalization block (nominal) and present-value block. Capitalization mainly defers recovery; at the utility's own cost of capital the present-value cost to ratepayers is the income-tax gross-up on the equity return, which is why the present-value figures are the smaller. The objection is to the classification and to the return earned on a purchase of service, not to the size of the number.
304 Response to CalAdv DR-001, Q3, attachment [Confidential Information Begins]……………………………….……
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accountant, I understand FASB ASC 350-40 to apply only to internal-use software, and to treat a hosted arrangement as a software license only where the customer has the contractual right to take possession of the software without significant penalty and could feasibly run it on its own or a third party's hardware; a hosted arrangement that conveys no such right is a service contract, and its fees are expensed as the service is received.[305] A prepaid carrier connectivity fee buys no plant, property or equipment, is not software of any kind, and is a cost of operating the meters once they are installed; it falls under the last of the policy's provisions, not the first three.

The prepayment structure is a commercial design, not an accounting conclusion [Confidential Information Begins]………………….…………………..……………………………..
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…..…[Confidential Information Ends].[306] SDG&E's stated basis is D.24-12-074's uncontested adoption of its 2024 General Rate Case methodology for capitalizing prepaid

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… ....[Confidential Information Ends].

[305] FASB ASC 350-40-15-4A (a hosting arrangement is within the internal-use software guidance only if the customer has the contractual right to take possession of the software at any time during the hosting period without significant penalty and it is feasible for the customer to run the software on its own hardware or contract with another party unrelated to the vendor to host it) and 350-40-15-4C (a hosting arrangement that does not meet both criteria is a service contract); Accounting Standards Update No. 2015-05, Customer's Accounting for Fees Paid in a Cloud Computing Arrangement (April 2015); ASU No. 2018-15 (August 2018), which applies the internal-use software guidance to the implementation costs of a hosting arrangement that is a service contract and leaves the hosting fees themselves as expense over the term of the arrangement.

[306] Response to CalAdv DR-002, Q5.b: "Appendix PF_Compensation and FRM" § 2.4(d); Vendor 1 "Appendix C1" (ASSUMPTIONS); Selected Vendor "SDG&E AMI 2.0 RFP Solution Architecture Overview" at 5; Response to CalAdv DR-003, Q30.b, incumbent RFQ proposal at 4 and 10 (all confidential).

software and hardware agreements,[307] which reaches the prepaid head-end and capability licenses but not the **confidential** of carrier connectivity charges, neither software nor computer hardware, and which did not consider whether ratepayers should pay a return on a prepayment for a service repurchased every five years for the life of the system. The Commission should direct that recurring vendor charges be recorded as expense, that the prepayments in the Application be recovered as expense over the service period they cover, and that any future request for the platform disclose the full life-cycle of recurring charges.

C. Depreciation lives

Q. What lives does SDG&E propose?

A. Fifteen years for meters, modules and installations, thirteen years for communication equipment and five years for software, "subject to revision in a future general rate case."[308] Its NextGen cost-benefit analysis, by contrast, uses a twenty-year analysis period matched to the manufacturer's design life of the electric meters,[309] and the manufacturer designs the meters for twenty years.[310]

Q. Why does the choice matter?

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[307] Response to UCAN DR-02, Q12.a (SDG&E "requested authorization in its 2024 General Rate Case (GRC) to capitalize prepaid agreement costs relating to IT software and computer hardware to Plant" and "is relying upon the Commission's approval of this request in Decision (D.) 24-12-074 page 804"). The decision lists, among "other methodologies related to rate base [that] are also uncontested," the "capitalization of prepaid agreement costs associated with software and computer hardware such as cloud Software as Service license arrangements, reserved cloud capacity, and new software and hardware maintenance costs," and "finds the above methodologies related to rate base to be reasonable and adopts them." D.24-12-074 at 803–804 (§ 37, Rate Base and Rate of Return).
[308] Ex. SDG&E-06 at CWB-6, Table 6-3.
[309] Ex. SDG&E-07-2E at NR/DT/MW-8, lines 2–6 ("All costs and benefits are evaluated over a 20-year analysis period, consistent with the manufacturer specified design life of the SM 2.0 electric meters"; the period "begins in 2026 and extends through 2045 (2026 – 2027 system implementation period, 2027 – 2031 meter deployment period, 2032 – 2045 benefits realization period)").
[310] Response to CalAdv DR-003, Q2 ("The manufacturer lists a design life of 20 years for SM 2.0 meters."); Ex. SDG&E-07-2E at NR/DT/MW-8, lines 2–3.

A. The depreciation life and the benefit life should be the same, because both are statements about how long the assets will serve. The purpose of the depreciation allowance is "to ensure recovery of invested funds over the economic life of the physical capital in which they have been embodied,"[311] so that the company recoups its investment "during their estimated useful-service lives"[312] and, where the estimate proves wrong, the remedy is a "midstream re-estimate of remaining-life expectancy" so that "the dates of complete amortization can be made to correspond fairly well to the dates of the actual retirement."[313]

Relevant here is that SDG&E's own cost forecast appears to assume that it buys electric meters with a twenty-year warranty. [Confidential Information Begins]………………… ………………………………………..…………………………………………… ……………………………………………………………………..……………… ………[Confidential Information Ends].[314]

A fifteen-year recovery of an asset expected to serve twenty years front-loads the revenue requirement onto the customers of 2028–2043 and leaves the customers of 2044–2048 paying the vendor's recurring charges on assets that have been fully recovered (the benefit of fully depreciated assets that SDG&E invokes[315] does not extend to those charges); in

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[311] Kahn at 117.
[312] Bonbright at 198.
[313] Bonbright at 213.
[314]Ch. 3 Workpaper 1 [Confidential Information Begins]……………………………………………………… ………………...……………………………………………………………………………………… ………………..……………………………………………………………………………………… ……………………………………………………………………………………………………… ……………………………………………………………………………………………………… …[Confidential Information Ends]
[315] Response to UCAN DR-02, Q13.a ("when Smart Meter 2.0 assets remain in service beyond their authorized useful lives, ratepayers benefit from the continued use of fully depreciated assets").

SG-2 the twenty-year life lowers the annual revenue requirement of the Application by about 5 percent in 2028–2036 and raises it after 2040, and because the return on rate base runs longer it raises the present-value cost of the revenue requirement by about 2 percent. I recommend twenty years not because it is cheaper on a present-value basis, since it is not, but because it matches the horizon SDG&E itself adopts for its cost-benefit analysis and the life the manufacturer designs the meters for, and because a utility that recovers its investment over fifteen years while evaluating cost-effectiveness over twenty years is taking one position for ratemaking and another for cost-effectiveness.

The SM 1.0 meters were also designed for twenty years, and SDG&E now proposes to retire them on a seventeen-year system life.[316] The Commission may take that history as a reason to keep the fifteen-year life for SM 2.0. If it does, the same doubt about whether the meters will serve their design life calls for a protection SDG&E has not proposed: a rule that ratepayers do not pay a return on SM 2.0 plant that is retired, before it is fully depreciated, for reasons within SDG&E's control. Customers charged for plant retired before it is recovered "may complain, with justice, that they are being made to pay more than the marginal, or indeed the total cost of serving them; that the company is being permitted to recoup from them sunk costs that should have been charged against customers

[316] D.24-12-074 at 673 ("SDG&E acknowledges that the manufacturer designs these meters for a 20-year lifespan"); Response to CalAdv DR-002, Q4.a–b (17-year system life; SDG&E's failure assessment "yielded a lifespan less than the 20-years").

in the past,"[317] and the risk of "unanticipatedly rapid obsolescence" is one of the risks the equity return is set to compensate.[318]

SDG&E's own procurement asked for an even longer life. [Confidential Information Begins]…………………………………………………………………..…………………
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....[Confidential Information Ends][319]

The same principle governs the unrecovered cost of the SM 1.0 devices that will be retired under any scenario. At May 31, 2026 those assets carried a net book value of $118 million ($71 million electric, $47 million gas) on an installed cost of $476 million, depreciated over the fifteen-year life adopted in the 2012 general rate case; on retirement the balance is charged to accumulated depreciation and stays in the general-rate-case revenue requirement.[320] The separate application SDG&E anticipates covers the SM 1.0 servicing costs recorded in the memorandum account, not that balance.[321] Whether that balance is addressed in this proceeding or in the 2028 general rate case, the decision should be made

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[317] Kahn at 119.
[318] Kahn at 120 ("It is their function, not that of consumers, to bear the risks of unanticipatedly rapid obsolescence; their rate of return ought to be high enough to compensate for such risks"); Bonbright at 153 and 189 (obsolescence risk allowed for in "fair rates of return well in excess of interest on secure loans").
[319] Response to CalAdv DR-002, Q5.b: "Appendix T" § 2.1.1.1; "Appendix PR" § 10.3(a); "Appendix TF" §§ 3.1 and 3.1.1; Selected Vendor "Appendix N1" response § 3.1.1 and "Appendix R1" response, exceptions 70 and 102–103; Vendor 1 "Appendix C1" (ASSUMPTIONS) (all confidential).
[320] Response to SBUA DR-003, Q6.a–c and Table 6-1 (citing D.13-05-010).
[321] Response to CalAdv DR-001, Q3(m); Response to SBUA DR-003, Q6.b–c ("The undepreciated SM 1.0 asset balances are reflected within the overall revenue requirement calculations presented in SDG&E's 2028 General Rate Case.").

together with the SM 2.0 depreciation life and the early-retirement rule, because all three answer the same question: who pays for meters retired before they are fully recovered.

VI. THE ALLOCATION OF COSTS BETWEEN GAS AND ELECTRIC RATEPAYERS

Q. How does the Application allocate the revenue requirement?

A. Table 6-4 assigns $866.6 million to CPUC-electric, $420.4 million to CPUC-gas and $38.5 million to FERC, out of $1,325.5 million,[322] and the typical residential gas bill rises by $3.18 a month, 4.9 percent, in 2031,[323] against $2.53 a month, 1.6 percent, for a typical residential electric customer.[324] The workpaper supporting Table 6-4 shows every annual value in the gas, electric and FERC revenue-requirement tabs as a hard-coded number, with no allocation factor and no link to any cost category;[325] the allocation was performed in a model SDG&E has declined to produce.[326]

Q. What allocation factors does SDG&E say it used?

A. In response to UCAN's data request SDG&E supplied a table of factors by FERC account: electric meter capital 100 percent electric; gas module capital 100 percent gas; common software (account C303) 60.0 percent electric, 25.5 percent gas and 14.5 percent FERC; common O&M (account C903.1) the same; electric meter O&M 55.7/23.6/20.7; gas module O&M 70.2/29.8/0. In preparing that response SDG&E "identified that the allocation treatment applied to certain cost categories in the illustrative revenue

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[322] Ex. SDG&E-06 at CWB-7, Table 6-4.
[323] Ex. SDG&E-06 at CWB-8, lines 14–15, and CWB-9, line 1 and Table 6-6 (the residential transportation rate rises 6.3 percent).
[324] Ex. SDG&E-06 at CWB-8, lines 4–7 and Table 6-5 (the residential bundled rate rises 1.70 percent).
[325] Ch. 6 Workpaper 1, tabs "WP6.4.2 (Rev Req - FERC)," "WP6.4.3 (Rev Req - CPUC Elec)" and "WP6.4.4 (Rev Req - CPUC Gas)."
[326] Response to UCAN DR-02, Q11.a.

requirement forecast did not fully align with the treatment reflected in the associated FERC accounts," and supplied "Revised Allocations": electric and gas meter O&M assigned wholly to their own commodity; common software 55.7/29.8/14.5; common O&M 62.5/37.5/0.0. The common factors come from "an annual labor ratio study based on payroll information reported in FERC Form 1."[327]

Q. Can Table 6-4 be reproduced from those factors?

A. No. Attachment SG-3 applies each factor set to each of SDG&E's cost lines, loads every line at SDG&E's program-wide contingency and indirect-cost ratio and splits the Program Management capital by the share of device capital,[328] and converts the lines to revenue requirement by asset class with multipliers derived on the Reconciliation sheet of Attachment SG-2; the total reconciles to Table 6-4 within 0.1 percent. The results are in Table 4.

Table 4. Jurisdictional allocation of the SM 2.0 revenue requirement ($ million)

Allocation	CPUC-Electric	CPUC-Gas	FERC	Gas share
Table 6-4 as filed	866.6	420.4	38.5	31.7%
SDG&E's filed factors applied to SDG&E's categories	946.7	341.1	36.9	25.7%
SDG&E's revised factors (UCAN DR-02, Q11.b)	922.4	371.2	31.0	28.0%
Benefit-based: direct assignment; shared platform by endpoint counts	940.4	353.2	31.0	26.7%

Source: Attachment SG-3, "Allocation."

327 Response to UCAN DR-02, Q11.b.

328 SDG&E applied contingency at the program level, about 5 percent on vendor costs and about 11 percent on non-vendor costs, and not by cost category (Response to CalAdv DR-003, Q31.a); its allocation table lists an electric account and a gas account for Program Management capital without a percentage between them (Response to UCAN DR-02, Q11.b).

The factors SDG&E says it used produce a gas revenue requirement $79 million lower than the one in the Application; SDG&E's revised factors, $49 million lower. The gas depreciation in the workpaper, $229.5 million, is 30.2 percent of total depreciation, while gas modules and their installation are 25.7 percent of device capital; on the workpaper's own numbers, about 41 percent of the non-device capital was assigned to gas, against the 25.5 percent factor SDG&E reports. I cannot say from the record how the difference arose, because SDG&E has not produced the model, and that is itself the first finding: the Commission is being asked to adopt an allocation that the applicant's own stated method does not produce, and SDG&E's offer to explain individual components[329] does not substitute for the model.

Q. What allocation do you recommend?

A. A benefit-based allocation built on direct assignment, with the shared platform allocated by a metering-specific key rather than a payroll ratio: (1) electric meter and gas module costs, capital and O&M, to their own commodity, as SDG&E's revised factors now provide; (2) the NextGen capabilities, which SDG&E itself describes as "NextGen Enhanced Electric Capabilities"[330] and for which SDG&E has identified no gas functionality and quantified no gas benefit,[331] entirely to electric, including their connectivity increment and subscriptions; (3) the Foundational Technology costs

[329] Response to UCAN DR-02, Q11.a (SDG&E "is willing to provide additional explanation regarding the calculation approach and supporting assumptions" for "any specific revenue requirement component") and Q11.c (amounts derived by applying the factors to direct costs "may not replicate the revenue requirement model").
[330] Ex. SDG&E-03 at DT/BB-8, lines 10–11 (public version; lines 11–12 in the confidential version).
[331] Response to UCAN DR-02, Q11.c–d; Response to SBUA/TURN DR-001, Q16.b (Sept. 21, 2026) ("SDG&E has not separately quantified gas ratepayer benefits associated with the NextGen capabilities"); Ex. SDG&E-07-2E at NR/DT/MW-8, line 15, and NR/DT/MW-20, line 7 (the benefits evaluated are "Electric Grid Operations Benefits" and "Customer Insights: Real-Time Energy Monitoring Benefits").

identifiable to one commodity (the electric and gas connectivity prepayments) directly assigned; (4) the shared platform (head-end software, eSIM activation, the micro-mesh network hardware, decommissioning of the SM 1.0 network, vendor implementation services, and the internal and contract labor supporting them) split between electric and gas by endpoint counts, [Confidential Information Begins]……………………………………
…………………..[Confidential Information Ends][332] the micro-mesh hardware and the SM 1.0 mesh serve gas modules as well as electric meters,[333] and the platform's function is to read endpoints; (5) program management by the share of device capital, because the program's labor scales with device work; and (6) the FERC share retained at the level in SDG&E's revised factors, which is not at issue in my testimony.

The result is a gas share of 26.7 percent ($353.2 million), $67.2 million below the Application, of which none is NextGen. Alternative keys for the shared platform (device-capital share, or the data-volume baselines in the vendor's connectivity pricing) yield gas shares of 25.6 and 24.1 percent; endpoint counts are the most conservative of the three for gas ratepayers and the most defensible on cost causation.

Q. Why should gas ratepayers bear none of the NextGen costs?

A. Because they receive none of the capabilities. The Transformer Health and Load Management and Customer Insights capabilities are electric functions; SDG&E "has not identified any customer-facing gas-module functionality proposed as part of Smart Meter 2.0 that is unique to gas-only customers relative to Smart Meter 1.0"; and the only reason

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[332] Ch. 3 Workpaper 2, tab "WP 3.4.5-C," line 3 and note 1 [confidential].
[333] Ex. SDG&E-03 at DT/BB-6, lines 5–9 (public); Ch. 3 Workpaper 2, tabs "WP 3.4.7-C" and "WP 3.4.8."

NextGen costs reach gas rates is that the labor-ratio study assigns "shared utility functions" by payroll.[334] SDG&E's only gas-side suggestion, enhanced usage insights, rests on the modules' data granularity, not on NextGen.[335] SDG&E's own planning drew the line the same way: its March 2025 capabilities roadmap rates gas operations "Like to Have," with the note "Gas focus is asset replacement and safety. Electric will be more progressive," and only two of its thirty prioritized capabilities are gas capabilities.[336]

Under the filed factors, about $15 million of revenue requirement for NextGen is assigned to gas; under the revised factors, about $18.5 million, on the revenue-requirement multipliers in Attachment SG-2.[337] SDG&E "has not separately quantified gas ratepayer benefits associated with the NextGen capabilities," allocates 29.8 percent of NextGen capital and 37.5 percent of NextGen O&M to gas nonetheless, and "has not prepared quantitative comparisons of gas-related benefits and allocated costs."[338] Scoping Issue 2(k) asks whether the framework "apportions costs between gas and electric ratepayers commensurate with the benefits each receives"; for NextGen the benefit to gas is zero and the apportionment should be zero.

Q. What do you recommend for gas-only customers?

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[334] Response to UCAN DR-02, Q11.c–d.
[335] Response to SBUA/TURN DR-001, Q16.c (Sept. 21, 2026) ("enhanced gas usage insights and improved high-use detection associated with increased data granularity"); the Transformer Health and Load Management and Customer Insights applications that make up NextGen are not mentioned.
[336] Response to SDCP/CEA DR-001, Q3, attachment "SM 2.0 Capabilities Prioritization and High Level Roadmap" (Mar. 5, 2025), slides 5 and 37 (the deck carries an internal "SDG&E Confidential" marking; SDG&E's confidentiality declarations for the response cover only Question 12, and SDG&E has stated that the same marking on the parallel "AOTP" deck was not a designation, Response to SDCP/CEA DR-002, Q2.13.j).
[337] Attachment SG-3.
[338] Response to SBUA/TURN DR-001, Q16.b–c (Sept. 21, 2026).

A. SDG&E serves about 4,715 gas-only customer accounts.[339] They receive a replacement gas module with "updated communications and cybersecurity capabilities," and no NextGen capability.[340] The decision should provide that no NextGen-related cost, and no cost of electric-only platform functions, is recovered from gas-only customers, which the benefit-based allocation accomplishes at the commodity level and which SDG&E's rate design should carry through to the customer level.

Q. What should the Commission direct on the allocation itself?

A. Three things. First, that SDG&E serve corrected revenue-requirement tables (Tables 6-4 through 6-6) reflecting the allocation factors it disclosed, so that the record contains an allocation that matches the applicant's stated method. Second, that the Commission adopt the benefit-based allocation described above and illustrated in Attachment SG-3, as rules rather than as the dollar figures in the attachment: electric meter and gas module costs to their own commodity; the NextGen capabilities, with their connectivity increment and subscriptions, entirely to electric; the commodity-specific connectivity prepayments directly assigned; and the shared platform by endpoint counts. The decision should state the percentages those rules produce for the authorized scope, and the same rules should be applied to the Phase 2 scope when it is authorized. Third, that no change to the adopted allocation be made without Commission approval, by application or by Tier 3 advice letter, because the allocation determines what each class of ratepayers pays. SDG&E states that "allocation percentages may change over time" and that its forecast is "illustrative."[341] That

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[339] Response to UCAN DR-02, Q11.d.
[340] Response to UCAN DR-02, Q11.d.
[341] Response to UCAN DR-02, Q11.b.

is a reason to fix the rules in the decision, not to leave them to change during implementation. The annual report recommended in Section V should show the factors applied to each cost category and the resulting electric, gas and FERC shares, so that any departure is visible when it occurs.

Q. Does the cost boundary between this proceeding and the Test Year 2028 General Rate Case bear on the allocation?

A. Yes, though the issue is broader than allocation. SM 1.0 costs are to be recovered through a separate application,[342] and the ongoing maintenance of the SM 1.0 system "will be recovered through SDG&E's base business";[343] portions of the approximately $27.6 million SM 1.0 information-technology forecast in the memorandum account "relate to activities that were also contemplated as part of the Smart Meter System Upgrade proposal" the Commission declined to fund in D.24-12-074;[344] and the GRC requests lifecycle funding for the existing meter data and network systems and for grid platforms whose capabilities depend on SM 2.0 data.[345] SDG&E answers that Ordering Paragraph 51 lets it record costs "to service existing equipment."[346] Whatever the outcome of the pending motion to consolidate,[347] the decision here should require a workpaper-level cost map

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[342] Response to CalAdv DR-001, Q3(m) (SDG&E "anticipates filing that application once sufficient SM 1.0 balances have accumulated").
[343] Response to CalAdv DR-003, Q10.e.
[344] Response to SBUA DR-003, Q7(d).
[345] UCAN Response in Support of the Public Advocates Office Motion to Consolidate (Aug. 4, 2026) at 3–5 (citing A.26-06-015, Ex. SDGE-09, App. E at E-3 to E-4 and E-43; Ex. SCG-10/SDGE-14 at 139–140 and 154–157; Ex. SDGE-12 at 43–44).
[346] Response to SBUA DR-003, Q7(d) (quoting D.24-12-074, Ordering Paragraph 51, which authorizes the memorandum account "to service existing equipment" and directs an application covering the "Smart Meter system upgrade"); whether the upgrade scope the Commission declined to fund can re-enter through the memorandum account is a question for the SM 1.0 application, which the cost map recommended below should make answerable.
[347] Public Advocates Office Motion to Consolidate, A.26-06-014 et al. (July 20, 2026) (moving under Rules 7.4 and 11.1 to consolidate this proceeding, A.25-12-019 and A.26-05-002 with the Test Year 2028 General Rate Case,

identifying every metering-related cost by docket, account and period, and should provide that no SM 2.0 revenue requirement is placed in rates before the Commission has been able to test it against the GRC record. Attachment SG-5 contains the language.

VII. WHAT RATEPAYERS SHOULD RECEIVE: DATA ACCESS CONDITIONS OF APPROVAL, THE NEXTGEN CAPABILITIES, AND A TECHNOLOGY ADVISORY PANEL

A. Customer access to meter data falls short, and five conditions would secure it

Q. Please address customer data access.

A. Real-time data would reach only opt-in residential customers through an application SDG&E expects a single vendor to provide;[348] "neither SDG&E nor the CCAs will have access to interval data for their customers in real-time";[349] "[c]ustomers in non-residential customer classes will not have access to real-time energy data through SM 2.0 NextGen capabilities";[350] SDG&E "has not determined whether a fee will be charged" to opt in;[351] the residential meter's Wi-Fi interface will not be opened to customer devices ("integration with other Wi-Fi customer devices is not being proposed");[352] the back-office latency that delays interval data to CCAs by a day or more is unchanged;[353] and SDG&E "does not

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A.26-06-014 and A.26-06-015 (cons.)); UCAN Response in Support of the Public Advocates Office Motion to Consolidate (Aug. 4, 2026). The motion was pending when this testimony was prepared.

[348] Response to SDCP/CEA DR-001, Q28.d ("will be provided by a single vendor to ensure a consistent experience").

[349] Response to SDCP/CEA DR-001, Q15.e.

[350] Response to SDCP/CEA DR-001, Q15.b.

[351] Response to SDCP/CEA DR-001, Q18.c–d (SDG&E answered sub-parts c and d together).

[352] Response to Mission:data DR-001, Q5.c.

[353] Response to SD CCAs DR-003, Q3.10 ("there will be no change to the timing or latency of SDG&E's back-office processing").

track historical performance information, either average or 95th-percentile time from interval end to availability in Green Button Connect or CCA data feed."[354]

SDG&E later said commercial customers will keep real-time data through KYZ outputs on a Wi-Fi device it will install; residential customers have no equivalent.[355] Other parties address the legal obligations these facts implicate; I address them as a matter of value for money and recommend conditions that are inexpensive on SDG&E's own numbers. The conditions are not new policy. The Commission's functionality criteria for SM 1.0 required "[c]ustomer access to personal energy usage data with sufficient flexibility to ensure that changes in customer preference of access frequency do not result in additional AMI system hardware costs";[356] the Commission found in 2009 that "[t]o realize the benefits of AMI, customers and authorized third parties need access to the information provided by the meters on a real-time or near real-time basis" and ordered SDG&E to provide smart-meter customers "access to usage data on a real-time or near real-time basis no later than the end of 2011";[357] and in 2011 it ordered that "[t]he full rollout shall require smart meters to transmit energy usage data to the home so that it can be received by a HAN device of the consumer's choice," noting that "D.07-04-043 at 13 also authorized recovery of HAN-related funding" for SDG&E.[358]

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[354] Response to UCAN DR-02, Q18.b.
[355] Response to SD CCAs DR-003, Q1.b, Q1.c ("SDG&E will enable Wi-Fi capabilities for its commercial SM 2.0 meters"), Q1.i ("KYZ enablement device") and Q1.l (867 KYZ customers today); Response to SDCP/CEA DR-002, Q2.1.b (KYZ outputs "supporting real-time energy monitoring").
[356] D.07-04-043, § 6.1.1 (functionality criteria of the February 19, 2004 ruling in R.02-06-001).
[357] D.09-12-046, Finding of Fact 19 and Ordering Paragraph 4.
[358] D.11-07-056, § 1 and Ordering Paragraph 11; id., § 7.2 n.242.

The home-area-network channel that order required has been closed to new SDG&E connections since 2023, and the SM 2.0 meters "do not support Zigbee devices."[359] In D.22-12-009 the Commission allowed SDG&E to discontinue ZigBee support, on SDG&E's representations that customers were shifting to Wi-Fi devices and that it planned "to solicit for new smart meters in the near future," and found that "SDG&E new smart meter customers will not be utilizing ZigBee Technology."[360] When three parties to this proceeding petitioned to restore the connections after D.24-12-074 had denied the first SM 2.0 request, the Commission denied the petition as untimely,[361] and on rehearing it struck the decision's discussion of the merits while leaving standing its statement that "[w]aiting until the next application cycle when a record can be developed and other alternatives can be proposed is the appropriate course of action."[362] This Application is that cycle. A replacement of the meters is the occasion on which those directives are either carried forward or quietly retired.

Q. What conditions do you recommend?

A. I recommend five conditions:

1. *Fifteen-minute, two-channel interval data for all electric customers as a base feature.* SDG&E confirms that fifteen-minute, two-channel recording is included for all meters in the Foundational Technology scope, so the condition costs nothing

[359] Response to SD CCAs DR-003, Q12.a ("customers with Zigbee devices will no longer have access to real-time or near-real-time data"); Response to Mission:data DR-004, Q3.b (about 7,500 customers used ZigBee devices before the closure).
[360] D.22-12-009, § 7.3 and Finding of Fact 14; see also Findings of Fact 15 and Conclusion of Law 23.
[361] D.25-10-004, § 5.2, Finding of Fact 4 and Ordering Paragraph 1.
[362] D.26-05-036, Ordering Paragraphs 1–3 (deleting § 6 and part of § 8 of D.25-10-004); the quoted sentence stands in § 5.4 of the modified decision. SDG&E reads it the same way: it says the Commission "deferred its decision-making regarding customer access to data to this proceeding." Response to Mission:data DR-001, Q5.a–b.

incremental; it should be written into the decision so that it is not later characterized as a NextGen capability or offered at a charge.[363] The existing obligation is keyed to the meter: SDG&E must make usage data available "with hourly or 15-minute granularity (matching the time granularity programmed into the customer's smart meter), available by the next day," because "the consumer has a right to the usage data."[364] Once every meter records at fifteen minutes, that is the granularity every customer is entitled to.

2. *An open local data interface. The residential meter's embedded Wi-Fi interface should be enabled as a documented local interface for customer-chosen devices, at no opt-in charge, as SDG&E already proposes for commercial customers.* The Customer Insights application may be offered, but it cannot be the exclusive path to a customer's own real-time data; ratepayers should not pay for a platform whose data they can reach only through a single vendor's app. SDG&E now says the vendor and any routing to other providers are undetermined;[365] the condition settles that for the customer. The Commission's stated goal for the home area network was "to provide California customers with secure, private, and direct access to the disaggregated data available in the Smart Meters" through "a common interface for the devices of customers and third parties,"[366] and its rule for third-party data access is that "[u]tilities must provide data without charge" and recover incremental costs in

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[363] Response to UCAN DR-02, Q17.
[364] D.11-07-056, Ordering Paragraph 5 and § 4.2.
[365] Response to Mission:data DR-003, Q1.a (SDG&E "has not determined the vendor, contractual arrangement, or customer-facing application"), Q1.g and Q2.b (SDG&E "has not determined whether it will facilitate the transmission of a customer's real-time usage data from the customer's meter to a service provider selected by the customer that is not a vendor selected by SDG&E").
[366] D.11-07-056, § 7.2.

rates.[367] An undetermined opt-in fee for a customer's own data is inconsistent with both. The radio is already bought and paid for: [Confidential Information Begins]……………………………………………………………..……………

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…………[Confidential Information Ends][368] [Confidential Information Begins]…….

………………………………………………[Confidential Information Ends],[369] [Confidential Information Begins]… .... [Confidential Information Ends] SDG&E's own March 2025 roadmap placed "Home Area Network (HAN) & HAN Alerts" in its first wave of capabilities, recording that the SM 1.0 program "was shut down due to low customer participation, technology limitations with Zigbee, and impending SM 2.0 implementation; increasing pressure from CCAs for program to be reinstated."[370]

These conditions would hold SDG&E to its own account of the transition. Its 2022 testimony was that devices connected by ZigBee "will still remain connected until the customers' future new meters are replaced with a new meter not carrying ZigBee,"[371] which presented the new meter as the successor channel; the Application now proposes

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[367] D.14-05-016, Attachment A (Data Request and Release Process), step 2, and § 8.3.2.
[368] Response to CalAdv DR-002, Q5.b, Selected Vendor "Appendix C1" responses (EM sheet, all three rounds) and "SDG&E AMI 2.0 RFP Solution Architecture Overview" at 24 (confidential).
[369] Response to CalAdv DR-002, Q5.b: [Confidential Information Begins]………………………..………………
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… .... [Confidential Information Ends] (all confidential); see also Response to Mission:data DR-001, Q5.i (for Customer Insights "the new smart meters will need to connect to the customer's Wi-Fi").
[370] Response to SDCP/CEA DR-001, Q3, attachment "SM 2.0 Capabilities Prioritization and High Level Roadmap" (Mar. 5, 2025), slides 6 and 14.
[371] D.25-10-004, § 2 n.7 (quoting SDG&E's Chapter 1A testimony in A.22-05-003 at 20:1).

that the new meter's own local interface not be opened. Without the condition, the local-access channel ordered in 2011 and closed to new connections in 2023 on the strength of a coming Wi-Fi generation would not be reopened by that generation when it arrives. That is true on any schedule: under the Application and under the phased design in Section IV alike, the interface reaches a customer with the new meter, and it is the condition, not the deployment pace, that determines whether it reaches anyone.

3. *Measurable data-service levels, modeled on the RFP, with annual reporting. [Confidential Information Begins]…………………………………………………………………………………… …………………………………………………………………………………………………… …………………………………………………………………………………………………… ....[Confidential Information Ends]*[372] *Those are vendor-to-utility metrics. The decision should adopt service levels of that kind for delivery of validated interval data to SDG&E's own systems, to the Green Button and CCA data channels, and for on-demand reads, and require SDG&E to report performance annually.* The reporting matters because nothing of the kind exists for SM 1.0: SDG&E states that it "has not maintained a comprehensive annual benefits-realization analysis" and "does not maintain historical AMI 1.0 forecasts, business cases, or benefit analyses beyond the materials identified in, or relied upon, for the current Smart Meter 2.0 Application."[373] Nor will the contract supply the standard on its own: asked for the warranty term, performance guarantees and remedies it is negotiating, SDG&E answered that negotiations are ongoing

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[372] Response to CalAdv DR-002, Q5.b: [Confidential Information Begins]………………………………..………… ………………………………………………..…………………………………………………………………… …... [Confidential Information Ends] (confidential); Response to UCAN DR-02, Q18.a ("no final SM 2.0 master service agreement has been executed").

[373] Response to SBUA/TURN DR-001, Q12.a–b (Sept. 21, 2026).

and “the requested information … is not available.”[374] The condition converts a vendor’s promise to SDG&E into an obligation to customers, and it supplies the Phase 1 metrics in Section IV.

Relevant here is that the Commission adopted, as a reasonable SM 1.0 specification, the requirement “that the AMI system must provide 99.5% of all consumption data for 99.5% of the segment by 8:00 a.m. of the next day,”[375] and its data-access rules already require SDG&E to publish, for third-party requests, the “request fulfillment date (including explanations for any delays)” in its annual smart grid report.[376] For CCAs the point is parity: the Commission has held that its rules give CCAs “the full range of rights and responsibilities of a utility as it pertains to this metering data” and that, “[s]ince IOUs maintain the billing and metering services for CCAs, there is no reason to burden CCAs” with building their own tools;[377] a service level that measures delivery to the CCA data feed as well as to SDG&E’s own systems is how that parity becomes observable, and the CCA data plan described in Subsection C below, developed with the technology advisory panel and filed at the checkpoint, is how the present delivery (one to two days on SDG&E’s account, three to five as SDCP reports), which in my view does not meet Public Utilities Code section 366.2(c)(9),[378] is brought to the same standard.

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[374] Response to SBUA/TURN DR-001, Q11.e.
[375] D.07-04-043, § 7.3.1 and Finding of Fact 10.
[376] D.14-05-016, § 8.3.2.
[377] D.12-08-045, § 6.2.
[378] See Subsection C for the figures. SDG&E states that its process “is fully compliant with all relevant statutory and Commission requirements and SDG&E’s approved Electric Tariff Rule 27.” Response to SD CCAs DR-004, Q4.10.g.

A standard stated in hours also settles a question of vocabulary. In the petition proceeding, SDG&E described billing-quality data delivered to CCAs "within two to three days of the meter read" as "near real-time," and the petitioners answered that it is not.[379] On this record SDG&E defines both terms as an elapsed time "typically under one minute"[380] and disclaims any proposal to offer such data to SDG&E or CCAs.[381] The decision should adopt that definition at the meter and state the CCA and third-party standard in hours.

4. *A gas data plan.* SDG&E "has not performed a battery and network impact study evaluating hourly gas data transmission intervals," its proposed program "does not currently include implementation of one or two hour gas data transmission intervals," and it "has not determined whether such a study will be performed."[382] Scoping Memo Issue 2(l) asks whether a gas data availability and transmission standards plan should be required.[383] SDG&E should be required to file, at the checkpoint, a plan stating the read frequency, battery impact and customer presentment for gas interval data, so that gas ratepayers, who bear a quarter to a third of the cost, receive a defined benefit.

The plan has a starting point in the procurement: [Confidential Information Begins]…………………………………………………………..…………………

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....[Confidential Information Ends][384] what remains is to state the

[379] D.25-10-004, § 3 (summarizing SDG&E's response at 6–7 and the petitioners' reply at 15).
[380] Response to SDCP/CEA DR-001, Q30 ("the elapsed time—typically under one minute—between when an event occurs and when it is reported").
[381] Response to SDCP/CEA DR-001, Q21 ("The Application does not propose to offer real-time or near-real-time data to either SDG&E or CCAs.").
[382] Response to UCAN DR-02, Q19.
[383] Assigned Commissioner's Scoping Memo and Ruling (Aug. 18, 2026) at 6, Issue 2(l).
[384] Response to CalAdv DR-002, Q5.b, Selected Vendor "Appendix C1" (AMI NS C sheet) and "SDG&E AMI 2.0 RFP Solution Architecture Overview" at 29–31 (confidential).

trade-off SDG&E is making for gas customers and to report against it. The Commission has already directed that "gas usage and gas cost data shall be made available to customers in a manner similar to electricity usage information,"[385] while its smart grid metrics and reporting were confined to electric systems;[386] a gas data plan is where the gas half of this program acquires the reporting the electric half has had since 2012.

5. *Privacy terms for the vendor-hosted application and cloud-hosted data.* These are existing obligations rather than new conditions, but the decision should require SDG&E to confirm them for SM 2.0: that "as a utility proposes to collect personal information, it should propose for consideration by this Commission both limitations on the amount of personal information collected and the time period for data retention";[387] that any vendor handling usage data is bound by contract to practices "no less protective than those under which the covered entity itself operates";[388] and that a third party providing a usage-monitoring service that uses the data for a secondary commercial purpose "prominently discloses that secondary commercial purpose to the customer."[389] [Confidential Information Begins]………………………………………………………………………………… ………………………………………………………………………………………… ……….…………………………………….…[Confidential Information Ends][390] but neither

[385] D.12-08-045, § 5.2.
[386] D.12-04-025, § 3.2 and Findings of Fact 5–7.
[387] D.11-07-056, § 5.5.2.
[388] D.11-07-056, Attachment D, Rule 6(c)(1).
[389] Pub. Util. Code § 8380(c), as quoted in D.11-07-056, § 4.2.
[390] Ex. SDG&E-04, Appendix A (Customer Privacy Framework) at A-1 to A-3; Response to CalAdv DR-002, Q5.b, [Confidential Information Begins]………………………………………………………………………………… ……………………………………………………………………………………………………… ……………………………………………………………………………………………………… … ....[Confidential Information Ends] (confidential).

states a retention period for the Customer Insights data, identifies that application's vendor or secondary-use terms,[391] or commits that the executed agreement will carry the covenant.

B. The NextGen capabilities

Q. What NextGen capabilities does SDG&E propose to enable?

A. Two. SDG&E describes the NextGen capabilities as "enhancements that can be implemented at any time – now or in the future"[392] and "requests approval in this application to implement only a limited set."[393] The set is two items, Customer Insights (a third-party load-disaggregation application, opt-in) and the transformer-health, meter-transformer-mapping and phase-identification bundle; enhanced power quality analysis, distributed-resource management, electric-vehicle charging optimization and enhanced theft detection are listed as capabilities SDG&E "does not propose to deploy … at this time, but may seek to do so in the future."[394]

That is not the order SDG&E's own planning set six months before it filed. Its March 2025 draft prioritization sorted its top thirty capabilities into three waves: the first wave held the home area network, enhanced smart rates, voltage monitoring, energized-down-conductor analysis, enhanced power quality, hot-socket detection, theft and tamper identification, electric-vehicle and solar identification, and enhanced gas data delivery; the second held real-time load disaggregation, outage notification and fault identification; the third held phase identification and meter-transformer mapping (one item), transformer load

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[391] Response to Mission:data DR-003, Q1.a (SDG&E "has not determined the vendor, contractual arrangement, or customer-facing application").
[392] Ex. SDG&E-03 at DT/BB-33, lines 13–15.
[393] Ex. SDG&E-03 at DT/BB-8, lines 19–21.
[394] Ex. SDG&E-03 at DT/BB-35 n.22 and Table 3-9.

management, and load-profile forecasting.[395] The Application funds one second-wave item, two third-wave items and, of the fourteen in the first wave, only the home-area-network item, now recast as the opt-in Customer Insights application.[396]

Q. What does the platform SDG&E is buying make possible?

A. Considerably more than the Application proposes to use, and the vendor's record shows why the order of the capabilities matters. [Confidential Information Begins]……… [Confidential Information Ends]

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[395] Response to SDCP/CEA DR-001, Q3, attachment "SM 2.0 Capabilities Prioritization and High Level Roadmap" (Mar. 5, 2025), slide 6.

[396] [Confidential Information Begins]…… [Confidential Information Ends] (confidential). SDG&E describes its related capability-assessment materials as "brainstorming materials" reflecting "an early-stage ideation and market scanning exercise … rather than a feasibility assessment or commitment to develop, evaluate, or implement each item identified." Response to SDCP/CEA DR-002, Q2.6.a–b.

[Confidential Information Begins/Ends][397][Confidential Information Begins]…………… ……………………………………………………..………………..…………………… ……………………………………………………..………………..…………………… …..[Confidential Information Ends [398]

Q. Can custom applications be developed for the platform?

A. Yes. [Confidential Information Begins]……………………………………………..…… ……………………………………………………………………………………………… ……………………..………………………………………………………………………… ……………………………………………..……………………………………………… ……………………………………………..……………………………………………… ……………………………………………..……………………………………………… …....................[Confidential Information Ends][399] SDG&E's testimony acknowledges the mechanism, "over-the-air deployment of new edge applications to electric meters, access to a catalog of third-party grid edge applications,"[400] [Confidential Information Begins]

[397] [Confidential Information Begins……………………………………………………………………………… …................................[Confidential Information Ends] Selected Vendor "Appendix C1" response (Oct. 3, 2025), "Other Solution Components (Software)" (confidential).

[398] Response to CalAdv DR-002, Q5.b: Selected Vendor "Response to Post Shortlist Questions," item 4; "Response to Appendix N10," §§ 1.4, 3.1–3.7, 3.14, 4.1 and the closing narrative; "SDG&E AMI 2.0 RFP Solution Architecture Overview" at 26 and 46; Selected Vendor technical reference 98-3479 (edge-card security) at 6–7; "GridEdge_Pricing_LG" (Oct. 3, 2025); evaluator workbooks "FutureCapabilities_Evaluator26" and "FutureCapabilities_Evaluator12" (all confidential).

[399] Response to CalAdv DR-002, Q5.b: Selected Vendor "Response to Post Shortlist Questions," item 4; "Response to Appendix N10," closing narrative; "SDG&E AMI 2.0 RFP Solution Architecture Overview" at 26 and 46; Selected Vendor technical reference 98-3479 (edge-card security) at 6–7 (all confidential).

[400] Ex. SDG&E-05 at BMB-35, lines 10–13.

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....[Confidential Information Ends][401]

Q. Is SDG&E's benefit case for the two proposed capabilities robust?

A. Not particularly. SDG&E claims benefit-cost ratios of 2.7 for the transformer bundle and 2.9 for Customer Insights,[402] with no sensitivity analysis of any input. For the transformer bundle, the 100 avoided truck rolls a year is the 2022–2025 average of work orders SDG&E identified from technician notes and adjusted by judgment,[403] while the hours per event and the 2 percent reduction in customer-minutes of interruption (which supplies 62 percent of the benefit) are, in SDG&E's words, "expert-informed planning estimates rather than the output of separate historical operational datasets";[404] a further 33 percent is the avoided cost of a territory-wide mapping remediation project that SDG&E has never requested, that "[h]istorically" its processes "did not require," and that has no scope, plan or start date independent of SM 2.0;[405] SDG&E already monitors transformer loading and maintains

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[401] Ch. 3 Workpaper 2 (confidential), [Confidential Information Begins]……………………………..……………
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.…[Confidential Information Ends]

[402] Ex. SDG&E-07-2E at NR/DT/MW-28, line 14, and NR/DT/MW-29, lines 2–7.

[403] Response to CalAdv DR-008, Q8 ("The correct totals are: 2022: 112; 2023: 89; 2024: 103; and 2025: 96, for an average of 100."); Response to CalAdv DR-006 (July 24, 2026), Q2.b ("applied the operational experience of the subject matter experts to arrive at a conservative figure") and Q2.d ("technician notes"). The 2 percent reduction in customer-minutes of interruption is applied to 2025 outage data. Response to CalAdv DR-006 (July 31, 2026), Q43.a.

[404] Response to CalAdv DR-008, Q4.a (quotation) and Q7.a (no separate calculation; incorporated by reference in the responses to Q11–Q14, Q17, Q19–Q28, Q31–Q32, Q38–Q43 and Q45, and in Q34.b and Q35.b); Response to CalAdv DR-008, Q34.a (20 percent mis-mapping "developed as a planning assumption"); Response to CalAdv DR-006 (July 31, 2026), Q26.b (75 percent phase-balancing efficiency "developed using the operational experience and engineering judgment of SDG&E subject matter experts").

[405] Response to CalAdv DR-006 (July 31, 2026), Q29.a, Q29.c, Q31.a, Q32.a ("SDG&E does not have a detailed scope of work or project plan."), Q32.c (a start "following the completion of the SM2.0 project, which is required for this effort") and Q32.d. SDG&E's explanation for the need is that "[a]s the distribution system evolves and increasing electrification, distributed energy resources, and other advanced grid capabilities require enhanced visibility into load connectivity and phasing, the value of obtaining this information has increased." Id., Q29.c.

meter-to-transformer associations, and says the bundle "enhances" and "improves the accuracy" of that work, an improvement over a baseline it has not measured;[406] and the bundle carries no capital or O&M expenditure after 2031 in SDG&E's analysis,[407] although its meter-to-cloud connectivity is, in SDG&E's own words, "recurring," as are the vendor's application and analytics fees.[408]

For Customer Insights, the 1.95 percent bill saving is half of a 3.9 percent figure from an evaluation of a Wisconsin utility's program in which participants received free monitoring hardware, smart plugs and paid demand-response events; the study "did not utilize a randomized control group," SDG&E "did not perform a separate normalization, calibration, or adjustment" of it for its own territory, had no contact with its authors, and ran no total-resource-cost test;[409] the saving is assumed to persist for seventeen years; the Wisconsin evaluation found four-year persistence but attributes it to "continued interaction with the program," and SDG&E's own experience with standalone opt-in insight tools is that they "tended to produce limited and temporary impacts" and that "customer interest

[406] Ex. SDG&E-03 at DT/BB-30, lines 21–23, and DT/BB-31, lines 5–7. SDG&E performs this work today through "engineering analysis, historical load data and field inspections" and "existing GIS records." Response to CalAdv DR-005, Q17.b. It does not track field visits duplicated or work orders caused by inaccurate mapping and has not audited its mapping records in the past five years. Response to CalAdv DR-008, Q18.a, Q18.c and Q36.a.
[407] Response to CalAdv DR-008, Q2.a ("$0.0 million in capital expenditures during the 2032-2045 period") and Q2.d ("$0.0 million" of O&M for 2032 through 2045); Ex. SDG&E-07-2E, Table V-1 ($(9.0) million of NextGen capability cost in 2032–2048, being revenue requirement on the earlier capital).
[408] Response to SBUA DR-002, Q4.a ("All costs are recurring," answering a question on the Meter-to-Cloud Connectivity line items); Response to CalAdv DR-002, Q5.b, Selected Vendor "Appendix C1" response (Oct. 3, 2025), "Other Solution Components (Software)" (confidential); Response to UCAN DR-02, Q12.c ("Any connectivity services required beyond 2031 are not included in these prepayments and would be subject to future cost recovery requests").
[409] Response to CalAdv DR-006, Q51.b, Q51.d, Q51.f and Q52.a–c (no TRC test because the capability "is not an energy efficiency program, but rather a Smart Meter 2.0 customer information and engagement capability"; the Cadmus study itself "did not include a TRC test"); Response to CalAdv DR-007, Q2.c and attachment (Cadmus, Home Energy Monitoring Report) at 19–21.

typically declined after an initial period";[410] the 20 percent adoption rate is a "planning assumption" discounted from a vendor-reported 30 percent and held constant for seventeen years "as a simplifying assumption";[411] and the application's costs continue "as long as the capability remains available to customers," with $28.9 million of them outside this Application.[412]

Q. What follows for the Commission's decision on the NextGen capabilities?

A. That they should be decided at the 2029 checkpoint, before Phase 2 deployment, rather than pre-approved now. SDG&E itself says the Commission "could elect to approve these NextGen capabilities at a later point," though it submits that approval now is warranted.[413] SDG&E confirms that the NextGen scope is severable from the base program and that the cost of deferral is postponed benefits;[414] but those benefits begin in 2029 and 2032 while costs begin in 2027,[415] and the open local data interface recommended in Subsection A above, not the NextGen capabilities, is what supplies the real-time access the Commission's orders require. Deferral therefore forgoes little, because the benefits

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[410] Response to CalAdv DR-005, Q16; Response to CalAdv DR-007, Q2.c and attachment (Cadmus, Home Energy Monitoring Report), Conclusion 8 (savings "persisted for at least four years"; "Savings persistence may be due to permanent behavior change or continued interaction with the program."), Table 6 (Phase V, the largest cohort at 413 participants: 0.7 percent, not statistically significant) and the accompanying recommendation of a follow-up analysis of persistence "in the absence of additional customer engagement." The program installed free monitors and ran paid demand-response events.

[411] Response to CalAdv DR-006 (July 31, 2026), Q49.a–b (citing "Utilities Achieve Large-Scale Customer Engagement and Results with Oracle"); Response to Mission:data DR-004, Q3.b ("approximately 7,500 (approximately < .05) of SDG&E customers utilized ZigBee Home Area Network (HAN) devices") and Q3.c (SDG&E does not consider that experience "directly comparable to, or predictive of" Customer Insights adoption).

[412] Response to CalAdv DR-008, Q1.h–k; Ex. SDG&E-07-2E at NR/DT/MW-25, lines 3–5.

[413] Ex. SDG&E-07-2E at NR/DT/MW-29, lines 17–20.

[414] Response to SBUA DR-003, Q9.d (the proposal is structured "to distinguish foundational AMI replacement functionality from optional NextGen capabilities, enabling the Commission to evaluate each component on its own merits"; deferral "would also postpone the customer and operational benefits associated with those capabilities"); see also Ex. SDG&E-07-2E at NR/DT/MW-2, lines 13–14 (NextGen capabilities "can be selectively added").

[415] Ex. SDG&E-07-2E, Tables III-2, IV-1, V-1 and V-2 (Customer Insights benefits from 2029; transformer-bundle benefits from 2032; costs from 2027).

SDG&E claims would scarcely have begun by the checkpoint while the charges would have been running since 2027, and it allows the decision to be made on a roadmap and a benefit record built during Phase 1 rather than on the planning estimates in the Application. How that roadmap and record should be developed is the subject of the next subsection.

C. Technology Advisory Panel

Q. How should the checkpoint deliverables, including the NextGen roadmap, be developed?

A. Through a technology advisory panel, as the Commission did for SM 1.0. In D.07-04-043, the Commission required quarterly implementation reports to the Energy Division and an annual report from a technology advisory panel on which UCAN and the Division of Ratepayer Advocates sat.[416] I recommend that the decision convene a similar panel for SM 2.0 within ninety days, chaired by the Energy Division, with SDG&E and its vendor as presenters.

Q. Who should sit on the panel?

A. The Public Advocates Office, the intervenors in this proceeding (particularly the CCAs serving SDG&E's territory), the California Independent System Operator and the California Energy Commission. The CCAs belong on it because the data channel at issue is theirs and because SDG&E's roadmap noted "increasing pressure from CCAs for program to be reinstated" (Subsection A). The ISO and the Energy Commission belong on it for two reasons. The first is statutory: "The commission, in consultation with the Energy

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[416] D.07-04-043, § 4 and Ordering Paragraph 3.

Commission, the ISO, and electrical corporations, shall evaluate the impact of deployment on major initiatives and policies including: (a) Implementation of new advanced metering initiatives."[417] The second is practical: the computing platform in these meters, and the application process that governs what runs on it, are where more accurate net-load forecasting and better coordination at the transmission-distribution interface could be built, and SDG&E's own roadmap lists "load profile forecasting" among the capabilities it ranked but did not propose.[418]

Q. What should the panel review?

A. Its charge would be to provide input, review, and report on annually and with the checkpoint application, (1) a NextGen roadmap listing the capabilities proposed for Phase 2, with the application, analytics and connectivity cost of each, the benefit of each measured against Phase 1 data rather than planning estimates, and the developer and publisher rights SDG&E holds so that utility-specific, aggregator- and CCA-requested use cases can be commissioned competitively; (2) a data plan for the CCAs, discussed below; (3) the gas data plan required by Subsection A above, which SDG&E's own roadmap placed in its first wave under "enhanced gas data delivery"; (4) the checkpoint metrics and their reporting; and (5) the meter failure re-forecast.

Q. What should the panel take up first?

A. The CCA data plan, because in my view the present arrangement does not meet the statute. Public Utilities Code section 366.2(c)(9) provides that "[a]ll electrical corporations shall

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[417] Pub. Util. Code § 8366.
[418] Response to SDCP/CEA DR-001, Q3, attachment "SM 2.0 Capabilities Prioritization and High Level Roadmap" (Mar. 5, 2025), slide 6.

cooperate fully with any community choice aggregators that investigate, pursue, or implement community choice aggregation programs," and that "[c]ooperation shall include providing the entities with appropriate billing and electrical load data, including, but not limited to, electrical consumption data as defined in Section 8380";[419] section 8380 defines that data as "data about a customer's electrical or natural gas usage that is made available as part of an advanced metering infrastructure, and includes incremental and monthly meter-specific electricity data, to the extent produced by that infrastructure."[420] I explained to the Commission in 2021 that the interval data the infrastructure produces is what a load-serving entity needs for the day-ahead demand schedules it must submit to the ISO by 10 a.m. the day before the trading day, and that data delivered days later "is too late to be of any use in preparing day-ahead forecasts and demand-bid submissions."[421] SDG&E says hourly interval data informs its load forecasting but that its procurement function receives interval load data two to three days after power flow, so neither load-serving entity gets next-day data[422] — which creates operational inefficiencies that customers ultimately pay.

Q. What is the present state of the CCA data access?

A. The Commission's Data Working Group Report described it in June 2026:

> *"SDG&E provides customer-level consumption data to the CCAs at a lower latency via a data solution developed specifically for CCAs at their request. CCAs can*

[419] Pub. Util. Code § 366.2(c)(9) (added by SB 790, Stats. 2011, ch. 599).
[420] Pub. Util. Code § 8380(a).
[421] R.20-11-003, Direct Testimony of Samuel Golding on behalf of UCAN (Jan. 11, 2021) at 8–10, and in particular at 9, lines 10–18.
[422] Response to SDCP/CEA DR-001, Q9 ("SDG&E's energy procurement function does not use customer-specific meter data. It receives interval load data 2-3 days after the powerflow."), Q11.a–c and Q20.d ("SDG&E's Energy Supply & Dispatch group does not use customer-level meter data.").

> *directly query or access 15- or 60-minute interval data for their customers within 48-72 hours of usage, providing the most current interval data available. San Diego Community Power (SDCP) reports that this data is received between 3 to 5 days of power flows, for approximately 95% of accounts. SDCP reports that they have encountered several issues working with these data however, including problems with the geolocation of some customer premises; inability to identify accounts who have been impacted by PSPS events or disconnected as a result of non-payment; difficulty in identifying data changes; a lack of clarity around data quality/status codes; confusing additional data columns and values; potentially missing data; and difference between API and interval usage data received via 867. Clean Energy Alliance (CEA) also reports data delays when 'networks undergo corrections, and all accounts are impacted' until resolved."*[423]

The same report records that SDG&E "runs a single daily AMI cycle from midnight to 6:30 AM that collects the prior 24 hours of reads (with a 4-day retry window for missing data), with Itron Enterprise Edition (IEE) MDMS (housed on-premise; billing data store retained for 42 months) completing VEE processing by 8:00 AM at greater than 99% actuals and less than 1% estimation."[424]

On SDG&E's own account the CCA data lake is populated at 2 a.m., about 26 hours after collection begins, which it calls access "within 24-48 hours of power flow";[425] the Data

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[423] Data Working Group Independent Facilitator Report, R.22-11-013 (June 5, 2026; filed June 12, 2026 as Attachment 1 to the Administrative Law Judge's ruling) at 45–46.
[424] Id. at 41 (citing R.20-11-003, UCAN Reply Brief (Feb. 12, 2021) at 4, and Exhibits UCAN-04 through UCAN-07).
[425] Response to SD CCAs DR-004, Q4.10 (head-end collection and validation "usually completed by approximately 9:00 a.m."; data "transferred in full to the CIS by approximately 9:00 a.m." and processed there "from

Working Group puts CCA access at 48 to 72 hours and SDCP reports three to five days (quoted above). SDG&E states that it "does not anticipate any changes to CCA meter data access as a result of the SM 1.0 to SM 2.0 transition."[426]

Q. What should the CCA data plan do?

A. It should close that gap. A program that replaces every meter and every head-end in the territory, and that prices a next-day service level for the delivery of its own interval reads (Subsection A, condition 3), is the occasion to do so. SDG&E answers that the lag is CIS processing for billing-quality, CCA-attributed data, that bypassing its back office is unworkable, and that data-access rule changes belong in a statewide proceeding.[427] The data plan does neither: it should state, for the CCA channel, the elapsed time from validation to data-lake availability, the same service levels the decision adopts for SDG&E's own systems, the data fields and status codes, and the schedule for meeting them, and the Commission has already held that its rules give CCAs "the full range of rights and responsibilities of a utility as it pertains to this metering data."[428]

VIII. SUMMARY OF RECOMMENDATIONS

Q. Please summarize your recommendations.

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approximately 10:00 a.m. to 2:00 a.m."; the data lake "is made available for use at 2:00 a.m. once the full set of data has been processed") and Q4.10.a (confirming that CCAs begin receiving the data 26 hours after SDG&E begins receiving it); Response to SDCP/CEA DR-001, Q5.b ("within 24-48 hours of power flow") and Q26.b ("available by approximately 2:00am for CCAs to extract"). The 8:00 a.m. figure in the passage quoted above is from the 2021 record; SDG&E now puts validation at about 9 a.m.

[426] Response to SDCP/CEA DR-001, Q5.a.

[427] Response to SDCP/CEA DR-002, Q2.16.a (the CIS step associates the meter data "to both a customer and the CCA," reformats it "into the CCA data schema" and performs "additional estimations for complex metering scenarios") and Q2.7 (a bypass "is not a reasonable or workable approach"); SDG&E Reply to Protests (Feb. 2, 2026) at 3–4.

[428] D.12-08-045, § 6.2.

A. I recommend that the Commission:

1. Authorize the Foundational Technology platform and Phase 1 (failure replacement, replacement on request, and the capacitor-defect cohort) through 2029 at authorized amounts stated by category and year; require a checkpoint application by July 1, 2029 with the contents specified in Section IV.F; authorize Phase 2 only on that record; decide the NextGen capabilities and their recurring charges at the checkpoint on a roadmap and a benefit record built during Phase 1; and provide that failure replacement continues under the Phase 1 authorization until Phase 2 is decided.

2. Replace the two-way AMIBA with a one-way account capped at the authorized amounts; require an application for costs above the cap; apply a sharing band above the Phase 2 cap; amortize the memorandum-account balance over three years; require an annual report; and exclude recurring charges beyond the period the authorized amounts cover (2031 for the Application as filed) from the account.

3. Treat recurring software, connectivity and subscription charges as expense; require disclosure of their full life-cycle in any cost comparison; and adopt a twenty-year depreciation life for meters and modules, with early-retirement protection if a shorter life is retained.

4. Direct SDG&E to serve corrected revenue-requirement tables; adopt the benefit-based allocation illustrated in Attachment SG-3; assign NextGen costs entirely to electric; hold gas-only customers harmless; and require a workpaper-level cost map across this proceeding, the GRC, the memorandum account and the SM 1.0 application.

5. Condition approval on fifteen-minute two-channel data for all electric customers, an open local data interface at no charge, adopted data-service levels with annual reporting, a gas data plan at the checkpoint, and confirmation of the data-retention, vendor-contract and secondary-use terms the Commission's privacy rules already require.

6. Convene a technology advisory panel, as in D.07-04-043, chaired by the Energy Division and including the Public Advocates Office, the intervenors, the CCAs, the California Independent System Operator and the California Energy Commission, to review and report annually on the NextGen roadmap, the CCA data plan, the gas data plan, the checkpoint metrics and the failure re-forecast.

Q. What would ratepayers gain if the Commission adopted these recommendations?

A. Four monetary benefits and four that do not carry a dollar figure but are the reason the dollar figures are achievable.

The first monetary benefit is the deployment cost itself. On SDG&E's own failure forecast, the phased, failure-led design costs about $12 million (1 percent) less in present value than the Application's schedule, and on the trend of SDG&E's actual failures it costs about $92 million (10 percent) less; the checkpoint captures whichever of those turns out to be true without requiring the Commission to choose a failure path today.[429] The pure failure-led design, Scenario B, marks the outer end of the range at $35 million to $128 million (4 to 14 percent).[430]

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[429] Attachment SG-2, "Results"; Table 3 (Section IV.E).
[430] Table 3 (Section IV.E).

The second is the treatment of the recurring charges: expensing the subscription prepayments rather than capitalizing them removes about $12 million of return and tax gross-up from the amounts in the Application and about $84 million over the life of the platform.[431]

The third is the allocation: applying SDG&E's own disclosed factors to its own cost categories moves $49 to $79 million of revenue requirement off gas ratepayers, and the benefit-based allocation in Attachment SG-3 removes every NextGen-related dollar from gas rates, so that the approximately 4,715 gas-only customer accounts pay for the module they receive and nothing else.[432] These are reallocations rather than reductions, but for gas ratepayers, whose residential rate impact SDG&E puts at 6.3 percent against 1.7 percent for electric, they are the difference between paying for what they receive and paying for what electric customers receive.[433]

The fourth is timing: amortizing the memorandum-account balance over three years spreads the roughly $20 million of 2024–2027 revenue requirement in SDG&E's Table 6-4 over three rate years rather than collecting it in the first year after a decision, as SDG&E's own illustration would,[434] and the twenty-year life lowers the annual revenue requirement by about 5 percent in 2028–2036 and aligns recovery with the twenty years of benefits SDG&E claims.[435]

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[431] Attachment SG-4, "Life-cycle," capitalization block.
[432] Attachment SG-3, "Allocation"; Response to UCAN DR-02, Q11.d.
[433] Ex. SDG&E-06 at CWB-8, Table 6-5, and CWB-9, Table 6-6.
[434] Ex. SDG&E-06 at CWB-7, Table 6-4 (CPUC-Gas and CPUC-Electric, 2024–2027: $(1.6) + $1.2 + $(2.7) + $9.6 + $(3.8) + $2.9 + $(6.2) + $21.1 = $20.5 million) and note 14 ("if a decision is issued in 2027, SDG&E will recover $84.8M, which reflects the 2024 through 2028 CPUC revenue requirements, beginning January 1, 2028").
[435] Attachment SG-2, "Results," sensitivities block.

Note that these figures should not be added into a single total. The deployment savings are present-value savings; the capitalization figures are nominal revenue requirement, and because capitalization mainly defers recovery, their present value at SDG&E's own cost of capital is smaller, about $3 million on the Application's prepayments and about $13 million over the life-cycle, which is the tax and property-tax gross-up that ratepayers avoid;[436] and the allocation and amortization items change who pays and when, not how much is paid in total, as does the twenty-year life (see Section VI).

Taken together, the quantified present-value savings to ratepayers as a whole are on the order of $15 million to $105 million depending on the failure path, or 2 to 11 percent of the Application's $937 million present-value cost, before any value is assigned to the checkpoint option or to the cost-sharing provisions, both of which exist to prevent costs that the model does not attempt to forecast.

The non-monetary benefits are these: ratepayers would not be committed to 1.6 million meters on a forecast that has not been validated and is already running below its first-year projection; the checkpoint converts that commitment into an option, exercised on observed unit costs, installation performance and failure rates. Cost risk would sit where the Commission's precedents and SDG&E's own procurement place it: a one-way account with authorized amounts, an application for anything above them, and a sharing band on Phase 2 mean that vendor and management performance, not ratepayers, absorb overruns, while early-retirement protection removes the risk of paying a return on plant retired before its life is out.

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[436] Attachment SG-4, "Life-cycle," present-value block (7.45 percent).

The cost of the program would be visible in full: the $359 million of post-2031 vendor charges, the SM 1.0 costs moving to a separate application and the base business, and the metering-related items in the general rate case would be mapped by docket, so that no dollar is recovered twice and the Commission's next decision on this platform is made on a complete record. And customers would receive the functionality the Application is named for: fifteen-minute two-channel data for every electric customer rather than an opt-in subset, an open local interface at no charge rather than access only through a vendor application, data-service levels enforceable by the Commission rather than left to the vendor contract, a plan for gas data that today does not exist, and a CCA data plan and NextGen roadmap to deploy cost-effective, grid-edge functionality reviewed by a technology advisory panel before the Commission decides Phase 2.

Q. Does this conclude your testimony?

A. Yes.

ATTACHMENT 1

A.25-12-012

UCAN Testimony Exhibits

SG 1-7

SG 1 – Samuel Golding Resume

SAMUEL GOLDING

PROFILE

Political economist, analyst, and executive management consultant.

Architect of Community Power agency governance and operating models, regulatory strategies and market reforms.

Educator recognized as an industry expert, technologist & strategist.

Advisor to Community Power agencies, Investor Owned Utilities, public power, municipalities, public advocates, labor and civic groups, technology firms and service firms.

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Linked
https://www.linkedin.com/in/samuelvgolding

MOTIVATION

Community
Collaboration
Bipartisanship
Effectiveness
Adaptation
Resilience
Affordability
Innovation

CAPACITY

Thought Leadership
Systems Thinking
Originality
Teamwork

EXPERTISE

Market Design
Agency Design and Operations

- Joint Action Governance
- Contracting & Financing
- Enterprise Risk Management
- Distributed Energy
- Regulatory Affairs
- Retail Products
- Compliance
- Budgeting
- Change Management

Board Engagement
Public Engagement
Industry Intelligence

EXPERIENCE

- **Community Choice Partners, LLC**
  Principal Consultant & Founder 2013- Present

  Architect of Community Choice 2.0 & 3.0 maturity models
  Power agency implementation, operational support, and market reform advice to C-level executives and stakeholders on policy and regulatory strategies, enterprise risk management, operational realignments, key performance indicators, staffing plans and culture, vendor assessments, competitive business intelligence and strategies, public relations and political campaigns, and stakeholder education.

- **Local Power, Inc.** 2011 - 2013
  Managing Director

  Consultancy that created Community Choice Aggregation.
  Responsibilities included managing projects, staff, and daily operations, in addition to consulting on financial modeling, Distributed Energy and customer-facing smart grid applications.

- **KEMA, Inc.** 2007 - 2011
  Senior Energy Analyst

  Global leader in Smart Grid and utility management consulting.
  Responsibilities included tracking hundreds of emerging technologies, Distributed Energy forecasting for states and utility territories, supporting grid integration simulations and 'Utility of the Future' management consulting teams.

EDUCATION

Bachelor of Arts, International Political Economy 2006
Colorado College
Study abroad: Fudan University & Maastricht University
Thesis: "*Retreat from Kyoto*"; why and how Federal energy policy became increasingly undemocratic over a period of 40 years.

SELECT PROJECT QUALIFICATIONS

COMMUNITY POWER COALITION OF NH

Coalition building, Joint Powers Agreement drafting, market design, rule development, regulatory engagement, data access reforms, power agency design, at-risk contracting & operational services. Q4 2019 — Q3 2025

UTILITY CONSUMER ACTION NETWORK

Nonprofit "utility watchdog" in San Diego. Lead expert in High DER Future, Extreme Weather, DER Data Access, PCIA, and Demand Flexibility proceedings. "OBMZTJT PG CCA smart meter data access and other retail value chain barriers, cost shift and anti-trust implications, and mitigating structural market reforms. Q1 2019 — ONGOING

IBEW LOCAL 11 & NECA LOS ANGELES

Local labor union & electrical contractors association. Engaged to educate broad range of stakeholders in Los Angeles on CCA 2.0 & 3.0 design and the PCIA reform risk through reports, meetings and board presentations. Initial focus on "South Bay" and "West Side" cities that subsequently joined the Clean Power Alliance. Design recommendations endorsed by: a Governor of the California Independent Grid Operator (CAISO), the former Assistant General Manager of the Northern California Power Agency (NCPA), the Chair of the Democratic Party Environmental Caucus, the California Alliance for Community Energy (CACE), the Executive Director of 350.org, the Sierra Club Angeles Chapter, and other organizations. Q3 2016 — Q1 2017

COUNTY OF LOS ANGELES

Drafting and submittal of "PCIA Homework" filing to CPUC. Summarized extant PCIA methodology, errors to reform in advance of CCA industry growth, and a variety of related issues (e.g., IRP coordination, POLR, CAM). Recommended procedural steps for CPUC along with CCA 2.0 & 3.0 design strategies for the industry to manage near-term risks. Subsequent recognition for correctly identifying 'over the horizon' issues that are challenging the industry at present. Q1 2016

CITY OF SAN DIEGO

Subcontractor to the Protect Our Communities Foundation. Correctly identified that San Diego was sufficiently large to trigger the reformation of the PCIA (an 'industry first'). Recommended a partial enrollment strategy to manage regulatory risk, and provided CCA energy and financial proforma forecasts accompanied by CA 2.0 design advice. Q4 2013 — Q4 2014

CONNECTICUT CCA STUDY DOCKET

Regulatory engagement support to community organizers, consisting of interrogatory responses, workshop participation, and facilitation of ten expert presentations (including 5 CCA CEOs from CA & MA as well as the NH Consumer Advocate). Q2 2020 — Q4 2021

LONG BEACH ENERGY RESOURCES DEPT

Engaged by municipal utility staff to support their CCA feasibility study effort. Review of bid submissions, scope of work negotiations with multiple contractors, regular project management support, analytical peer review, education for city staff on CCA issues and assistance in coordination with operational CCAs, public power entities and SCE over the course of the pSoject. Q2 2018 — Q4 2019

EAST BAY COMMUNITY ENERGY

Expert review and advice in the selection of a portfolio manager to assist in the launch and early-stage operations of the CCA; strategy discussions to evolve front-office structures and risk management capabilities. Q4 2017

SONOMA CLEAN POWER

Technical, financial and strategic consulting services during Phase 2 and 3 (full enrollment) through staff onboarding: load & revenue forecasting; customer data analytics (CCA INFO Tariff and utility EDI data); power supply contract management; procurement support including forecasting of open energy and capacity positions; validation of invoiced PPAs and CAISO wholesale market pass-through costs (charge codes); a variety of monthly, quarterly and annual compliance reports (EIA, CAISO, CEC and CPUC); select regulatory intelligence, business process streamlining & CCA staff tutorials; and program financial "proforma" modeling (for internal budgeting & external creditworthiness assessments of the agency as an off-taker). Q4 2013 — Q4 2014

DISTRIBUTED ENERGY ASSESSEMENTS

— CALIFORNIA PUBLIC UTILITIES COMMISSION

— SAN FRANCISCO PUBLIC UTILITIES COMMISSION

— CALIFORNIA ENERGY COMMISSION (PIER)

— CITY OF BOULDER, COLORADO

— STATES OF RHODE ISLAND, CONNECTICUT & MISSOURI

— UTILITIES: PG&E, SCE, SDG&E, SoCalGas (CA); HECO, MECO, MELCO (HW); XCEL ENERGY, PRPA (CO); NIPSCO (IN)

CONFIDENTIAL CLIENTS

CCA Agency: CEO advice on market reform strategies, stakeholder engagement and regulatory intelligence.
Q2 2019 — Q1 2020

Investor Owned Utility: community partnership advice (in non-CCA enabled markets).
Q2 2019 — Q2 2020

SELECT PUBLICATIONS & PRESENTATIONS

CALIFORNIA

Rulemaking 21-06-017: California Future Grid Study workshop presentations — recordings accessible online; see Workshop #1 from 3:10:40 to 3:22:00 (slides) and Workshop #2 from 3:57:40 to 4:16:30 (slides) — recommending implementation of a Statewide Data Hub, DER Registry, and Flex Market Platform to enable market-based integration of distributed resources to offset utility grid investments, with examples of successful deployments in other electricity markets. Q1 2024.

Rulemaking 20-11-003: legal briefs, testimony and evidence proving utilities unfairly withheld Smart Meter data from Community Choice Aggregators, and that this contributed to causing rolling blackouts — which prompted regulatory staff to implement data access reforms. 2020 to 2021.

California Assembly Utilities & Energy Committee: Written Comments and Oral Comments (at 3:45:30) explaining that the rolling blackout were partially attributable to utility withholding of Smart Meter data from Community Choice Aggregators. 12 October 2020.

Understanding the Community Choice Energy (R)evolution in California. LinkedIn article, providing an explanatory overview of the rapid development of the industry to-date. 15 October 2018.

Design Workshop: Community Choice 2.0 and 3.0. Organizer of 8-hour workshop on power agency design and evolution in CA, with 17 experts on 7 panels for ~75 industry experts in attendance. 24 April 2018.

Community Choice & Risk Management. Norton Rose Fulbright, Project Finance Newswire. June 2018.

Community Choice 2.0 & 3.0 Insights and Regulatory Risk Implications for Community Choice 2.0 & 3.0. Interview for the Stratton Report. 15 May 2018 & 15 November 2017.

Community Choice Energy: Evolution & Outlook. Tutorial overview webinar requested by the CEO of the American Public Power Association for their executives and senior staff. 6 September 2018.

NEW HAMPSHIRE

House Bill 755: a key component of the New Hampshire Energy Forward Act, re: reforms to utility systems necessary to enable market-based retail innovation and local projects. 2025.

CPCNH Enterprise Risk Management Policy Compliance Assessment Report. 20 January 2025.

DE 23-063 (Joint Utilities' Petition for Waiver of Certain Provisions of the Puc 2200 Rules): substantial contributions to CPCNH's Brief with Attachments, and Reply Brief, re: reforms to utility systems necessary to fully enable Puc 2200 rules. June 2024.

Substantial contributions to CPCNH's key documents, e.g.: Joint Powers Agreement, Cost Sharing Agreement and Member Service Contract, Energy Portfolio Risk Management, Retail Rates, and Financial Reserves Policies, Energy Portfolio Risk Management Regulations, and Electric Aggregation Plan templates. 2021-2022.

CPCNH Draft Business Plan and cost model. 14 August 2021.

A Distributed Economic Model Predictive Control Design for a Transactive Energy Market Platform in Lebanon, NH. IEEE (submitted). 7 December 2020.

DE 19-197 (NH Statewide Data Platform Docket): Direct Testimony & Rebuttal Testimony detailing how utility systems block innovation, how fully restructured markets function more efficiently, and how Community Power is designed to catalyze progress in NH. August and October 2020.

Community Choice Industry Overview Workshop Presentations. Organized 10 experts to present to the CT Public Utilities Regulatory Authority, including five Community Choice CEOs. 28 September 2020.

Taking Control: Communities Save Money & the Planet by Joining Forces with CCA (moderator). Radically Rural Conference, panel with April Salas and NH Consumer Advocate Don Kreis. 24 September 2020.

Community Power: Design Insights for New Hampshire. LES Conference. 15 November 2019.

Op-ed re: SB 286: NH bill is step toward true community energy. The Concord Daily. 23 July 2019.

Memo re: SB 286 to the New Hampshire Governor and Office of Strategic Initiatives. 17 July 2019.

SG 2 – Deployment Scenario Model

CONFIDENTIAL VERSION ONLY

No Public Version

SG – 3 Gas-Electric Allocation Model

CONFIDENTIAL VERSION ONLY

No Public Version

SG 4 – Recurring SaaS and Connectivity Model

CONFIDENTIAL VERSION ONLY

No Public Version

SG 5 – Proposed Ordering Paragraphs

ATTACHMENT SG-5

PROPOSED ORDERING PARAGRAPHS

This attachment sets out proposed ordering-paragraph language for each recommendation in my testimony. The paragraphs are drafted so that the Commission can adopt them as written or by reference; bracketed items identify an appendix to the decision that would carry the authorized amounts by cost category and year, the allocation factors and the data-service levels. Section references are to my testimony.

1. San Diego Gas & Electric Company (SDG&E) is authorized to implement Phase 1 of its Smart Meter 2.0 program through December 31, 2029, at the authorized amounts set out in Appendix [ ] to this decision by cost category and year, consisting of:

   (a) the Foundational Technology platform described in Exhibit SDG&E-03, Chapter 3 (head-end system, communications network, and data and billing integration);

   (b) the replacement, with Smart Meter 2.0 devices, of Smart Meter 1.0 electric meters and gas modules that fail after the platform enters service;

   (c) the proactive replacement of Smart Meter 1.0 electric meters in the capacitor-defect population identified in the vendor's November 2020 root-cause analysis, as validated by capacitor date code and serial range, not to exceed the 403,401 such meters SDG&E reported in service as of June 23, 2026 or the smaller number the validation supports, beginning with the December 2009 date code and sequenced by network cell, together with the Smart Meter 1.0 gas modules in each network cell so replaced; and

(d) the replacement of a customer's Smart Meter 1.0 electric meter, at the failure-replacement unit cost, upon the customer's request or upon the customer's enrollment in a rate or program requiring fifteen-minute interval data, or, where the legacy network can support it, the remote reprogramming of that meter to record fifteen-minute intervals.

From the start of Phase 1, SDG&E shall record estimated bills by cause and the count of Smart Meter 1.0 gas modules that lose communication upon the removal of an electric meter, and shall retain monthly device-failure data by device class, capacitor date code and installation year.

2. SDG&E shall not deploy Smart Meter 2.0 electric meters or gas modules beyond the scope of Ordering Paragraph 1 unless and until the Commission authorizes a second phase by decision. By July 1, 2029, SDG&E shall file an application reporting Phase 1 results through the first quarter of 2029 and proposing a Phase 2 deployment plan with authorized amounts. The application shall include:

(a) recorded Phase 1 costs against the authorized amounts in Appendix [ ] by category and year, and unit cost per device installed against the contract price;

(b) monthly Smart Meter 1.0 device failures since January 1, 2026 by device class, capacitor date code and installation year; a re-forecast of the remaining Smart Meter 1.0 fleet with its model and inputs in native electronic format; and a back-test of that re-forecast against actual failures from 2026 through the most recent quarter;

(c) transition metrics: installation rate and first-read success; the number of replacements made under Ordering Paragraph 1(d); interval-data delivery against the service levels in the executed vendor agreement and in Appendix [ ]; the count of Smart Meter 1.0 gas modules that lost communication upon removal of an electric meter; estimated bills by cause; interval-read completeness by network cell; Smart Meter 1.0 network-mitigation expenditures; and the status of the Smart Meter 1.0 field area routers;

(d) vendor performance: Smart Meter 2.0 device failure rates against the excessive-failure thresholds in the executed vendor agreement; warranty claims made and paid; and the executed agreements with the incumbent vendor for Smart Meter 1.0 device supply, head-end support and hosting through the end of the transition;

(e) benefits realization and forward plans: the NextGen capabilities in service and their measured use; interval data delivered to community choice aggregators (CCAs) against the service levels in Appendix [ ]; the NextGen capability roadmap and the CCA data plan required by Ordering Paragraph 12; and the gas data plan required by Ordering Paragraph 10; and

(f) a Phase 2 proposal pricing, at a minimum, continued failure-led replacement and a mass replacement of the remaining fleet on a common present-value basis from the re-forecast, with the revenue-requirement model filed in native electronic format.

SDG&E shall supplement the application quarterly with data through the most recent quarter until the record closes. Until the Commission authorizes Phase 2, SDG&E shall continue to replace failed Smart Meter 1.0 devices with Smart Meter 2.0 devices under Ordering Paragraph 1, and the authorized amount for failure replacement shall be extended at the annual rate set out in Appendix [ ].

3. SDG&E is authorized to establish a one-way Advanced Metering Infrastructure Balancing Account (AMIBA), for Phase 1 and for any Phase 2 the Commission authorizes, to record

Smart Meter 2.0 costs up to the authorized amounts in Appendix [ ]. Any amount by which recorded costs fall short of an authorized amount shall be returned to ratepayers. Costs in excess of an authorized amount shall not be recorded to the AMIBA and may be recovered only upon application, not by advice letter, and a showing of reasonableness. Any Phase 2 authorization shall specify a band above the Phase 2 authorized amount within which costs are shared between shareholders and ratepayers according to a stated percentage, and shall provide that costs above the band are recoverable only following a reasonableness review; no shareholder reward shall be paid on costs below an authorized amount.

4. The balance recorded in the Smart Meter 2.0 Memorandum Account from January 1, 2024 through the effective date of this decision, to the extent found reasonable, shall be transferred to the AMIBA and amortized in rates over thirty-six months beginning with the first January 1 rate change following this decision.

5. Recurring software-as-a-service, meter-to-cloud connectivity and capability subscription charges for the Smart Meter 2.0 program shall be recorded as operating expense in the period the service is received. Prepayments made for such services shall be amortized as expense over the service period they cover, and no return shall be earned on the unamortized balance; the rate-base methodology for prepaid software and hardware agreements adopted in D.24-12-074 shall not apply to these charges. Recurring charges for service beyond the period covered by an authorized amount, which for the Phase 1 authorization ends on December 31, 2031, shall not be recorded to the AMIBA and shall be forecast in SDG&E's Test Year 2028 General Rate Case or its successor; any Phase 2 authorization shall state the corresponding date for Phase 2. Any cost comparison SDG&E presents in this or a successor proceeding shall disclose the full life-cycle of such charges.

6. Smart Meter 2.0 electric meters, gas modules and their installation costs shall be depreciated over twenty years. [Alternative: If a fifteen-year life is retained, no return shall be earned on the undepreciated balance of any Smart Meter 2.0 asset retired before the end of its authorized life for reasons within SDG&E's control.]

7. Within sixty days of the effective date of this decision, SDG&E shall serve corrected versions of Exhibit SDG&E-06, Tables 6-4, 6-5 and 6-6, and the supporting workpapers, reflecting the allocation factors identified in its response to UCAN Data Request 02, Question 11.b, with formulas intact. The revenue requirement for the authorized program shall be allocated among the CPUC-electric, CPUC-gas and FERC jurisdictions under the following rules, illustrated in Attachment SG-3 to the testimony of Samuel Golding: each cost identifiable to one commodity, including the electric and gas connectivity prepayments, is directly assigned; shared platform costs are divided by endpoint count; and NextGen Technology costs, including their connectivity increment and subscriptions, are assigned entirely to the electric jurisdiction. Appendix [ ] states the percentages these rules produce for the authorized scope; the same rules shall be applied to the Phase 2 scope when it is authorized. No change to the adopted allocation shall be made without Commission approval, by application or by Tier 3 advice letter. No NextGen-related or electric-only platform cost shall be recovered from gas-only customers.

8. SDG&E shall file annually, by March 31, a report on Smart Meter 2.0 spend against authorized amounts, devices installed, unit costs against contract, performance against the data-service levels in Appendix [ ], device failure rates, the balances in the memorandum and balancing accounts, and the allocation factors applied to each cost category with the resulting CPUC-electric, CPUC-gas and FERC shares.

9. Within ninety days of the effective date of this decision, SDG&E shall serve a workpaper-level cost map identifying every metering-related cost recorded or forecast in this proceeding, in its Test Year 2028 General Rate Case (A.26-06-015), in the Smart Meter 2.0 Memorandum Account, and in its planned Smart Meter 1.0 application, by docket, FERC account and period, and identifying any cost that is dependent on, duplicative of, or contingent upon a request in another proceeding.

10. The following data-access conditions apply to the authorized program:

    (a) fifteen-minute, two-channel interval recording shall be enabled for all Smart Meter 2.0 electric meters as a base feature at no incremental charge, and usage data shall be made available to each customer at the granularity programmed into the customer's meter;

    (b) SDG&E shall enable the Smart Meter 2.0 meters' local wireless interface as a documented interface for customer-authorized devices, for all customer classes, at no opt-in charge, and shall include in the base program at least one qualified application through which customers may obtain their own real-time data locally, reporting its cost with the application required by Ordering Paragraph 2; no vendor application shall be the exclusive path to a customer's own real-time data;

    (c) SDG&E shall deliver validated interval data to its own systems, to the Green Button channels and to the CCA data channel in accordance with the service levels in Appendix [ ], stated in hours, and shall report performance in the annual report required by Ordering Paragraph 8; for purposes of this decision, "real-time" data means data made available at the meter within one minute of measurement, and the standards for delivery to CCAs and third parties are stated in hours;

(d) with the application required by Ordering Paragraph 2, SDG&E shall file a gas data plan stating the read and transmission frequency, battery and network impacts, and customer presentment for gas interval data; and

(e) within ninety days of the effective date of this decision, SDG&E shall file, by Tier 2 advice letter, confirmation for the Smart Meter 2.0 program of the data-retention period for usage data held in the vendor-hosted head-end and any customer application, the identity of the application vendor and the contractual terms binding each vendor to privacy and security practices no less protective than those under which SDG&E operates, and the disclosure to customers of any secondary commercial use of their usage data, consistent with D.11-07-056 and D.12-08-045.

11. Within ninety days of the effective date of this decision, the Energy Division shall convene a Smart Meter 2.0 Technology Advisory Panel, chaired by the Energy Division and including the Public Advocates Office, the parties to this proceeding that elect to participate, the CCAs serving customers in SDG&E's service territory, the California Independent System Operator and the California Energy Commission, with SDG&E and its vendors participating as presenters. The Panel shall review, and report to the Commission annually by March 31 and with SDG&E's Phase 2 application, on:

(a) a NextGen capability roadmap listing the capabilities proposed for Phase 2, their application, analytics and connectivity costs, the benefits of each as measured during Phase 1, and the application development and publication rights SDG&E holds under its vendor agreements;

(b) a CCA data plan specifying the service levels, data fields and status codes for the CCA data channel and the schedule for meeting the service levels in Appendix [ ];

(c) the gas data plan required by Ordering Paragraph 10(d);

(d) the metrics reported under Ordering Paragraph 2; and

(e) the Smart Meter 1.0 failure re-forecast.

The Panel is advisory; nothing in this Ordering Paragraph delegates any Commission authority.

12. SDG&E shall file the NextGen capability roadmap and the CCA data plan reviewed under Ordering Paragraph 11 with the application required by Ordering Paragraph 2. The NextGen Enhanced Electric Capabilities and their recurring charges are not authorized by this decision and shall be decided with Phase 2 on that record.

SG 6 – Discovery Responses Cited

ATTACHMENT SG-6 — DISCOVERY RESPONSES AND PRODUCED DOCUMENTS CITED IN THE TESTIMONY (PUBLIC)

This attachment reproduces, in full and without redaction, each SDG&E discovery response document cited in testimony that contains no material SDG&E has designated confidential, together with the cited pages of any public document produced with a response, and two documents from other Commission proceedings for reference. Discovery responses that contain any designated material are reproduced in full in Attachment SG-7 rather than in redacted form here. Each document is preceded by a cover sheet identifying it and the footnotes that cite it. Footnotes in the testimony identify each response by the data request and question numbers shown in this index; page references below are to this attachment's continuous pagination (lower right of each page). Workbooks and model files that SDG&E produced natively are listed at the end of the index and are served in native form.

INDEX

Item	Document	Source	Cited at footnote(s)	Attachment pages
P12	SDG&E Response to Cal Advocates Data Request 008	CalAdv DR-008	403, 404, 406, 407, 412	163–212
P13	SDG&E Response to Cal Advocates Data Request 006 (Part 1), July 24, 2026	CalAdv DR-006	117, 232, 255, 403	213–245
P14	SDG&E Response to Cal Advocates Data Request 006 (Part 2), July 31, 2026	CalAdv DR-006 (Part 2)	31, 403, 404, 405, 409, 411	246–288
P15	SDG&E Response to Cal Advocates Data Request 007	CalAdv DR-007	409, 410	289–295
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SG 7 – Protected Materials Cited

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