Application: A.26-02-001

Exhibit No.: SDGE-02-2R

Witness: Jeff DeTuri

SECOND REVISED

PREPARED ~~REVISED~~ TESTIMONY OF

JEFF DeTURI

ON BEHALF OF SAN DIEGO GAS & ELECTRIC COMPANY

CHAPTER 2 – COMMODITY/GENERATION

BEFORE THE PUBLIC UTILITIES COMMISSION
OF THE STATE OF CALIFORNIA

~~JUNE 1, 2026~~JUNE 17, 2026

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CHAPTER 2 – COMMODITY/GENERATION

I. OVERVIEW AND PURPOSE

The purpose of my revised direct testimony is to provide proposed rate design for the generation commodity component of SDG&E's demand flexibility pricing rates (Proposed DF Rates), pursuant to Ordering Paragraph (OP) 1 of Decision (D.) 25-08-049 (Guidance Decision). SDG&E submits this revised testimony pursuant to the April 30, 2026 Assigned Commissioner's Scoping Memo and Ruling (Scoping Memo) permitting SDG&E to provide supplemental and/or revised testimony prior to intervenor testimony to account for changes resulting from implementation of a new Medium Commercial customer class on April 1, 2026, which requires a new DF rate proposal.[1] SDG&E's Proposed DF Rates consist of two main commodity portions, the Marginal Energy Costs (MEC) and the Marginal Generation Capacity Costs (MGCC). The MGCC is further broken out by value which calculates the costs of long-term capacity, the flexible capacity costs, and the function to apply the costs. This chapter of testimony ends with an accounting of non-marginal costs.

My testimony is organized as follows:

- **Section I – Overview and Purpose**
- **Section II – Marginal Energy Cost (MEC)**
- **Section III – Distribution and Transmission Losses**
- **Section IV – Marginal Generation Capacity Costs (MGCC)**
- **Section V – Non-Marginal Generation Commodity Costs**

[1] Scoping Memo at 4; *see also* D.25-08-049 at COL 1 ("It is reasonable to [ ] direct SDG&E to file a consolidated application for DF Rate Proposals to comply with the guidance in this decision for all customer classes . . .").

- **Section VI – Summary and Conclusion**
- **Section VII – Witness Qualifications**

II. MARGINAL ENERGY COSTS (MEC)

For purposes of the Proposed DF Rates, SDG&E utilizes the CAISO Day-Ahead Default Load Agregation Point (DLAP) for the MEC.[2] The benefits of using a Day-Ahead CAISO price are explained in the Chapter 1 of testimony. Additionally, SDG&E will apply floor and ceiling prices as part of its customer protection as discussed in Chapter 4 of testimony.

III. DISTRIBUTION AND TRANSMISSION LOSSES

Pursuant to the Guidance Decision, SDG&E proposes a MEC that includes line losses reflecting the load-dependent nature of those losses.[3] SDG&E will include a factor for lost and unaccounted for energy as part of the DLF. DLFs account for the lost energy as it moves from the transmission system to the customer meter, that locational variation is the distribution line losses and lost and unaccounted for energy. These are important to account for because the CAISO system which will be used for pricing, see Section II MEC above, are at the transmission level but the customer usage is at the meter level which must account for the lost energy from the distribution system and any lost or unaccounted for energy. SDG&E proposes to use its Electric Energy Commodity Cost – Transition Bundled Service (EECC-TBS) tariff to provide the DLF calculation.[4] These calculations are based on a distribution loss study and are currently being used in rates like Schedule EECC-TBS. SDG&E's EECC-TBS tariff covers Direct Access customers who are in between service providers and must procure their energy from the utility on a temporary basis. The calculation is based on load, which meets the Guidance Decision's

[2] *See* Guidance Decision, Conclusions of Law (COL) 2 at 138.
[3] Guidance Decision, COL 3 and 4 at 138.
[4] SDG&E, *EECC-TBS ELECTRIC ENERGY COMMODITY COST - TRANSITIONAL BUNDLED SERVICE*, accessed 11/21/2025 at Sheet 2, *available at:* https://www.sdge.com/tbs-dwr/tbs.

criteria of reflecting the time or load-dependent nature of the losses. Transmission voltage service has no DLF because it does not flow on the distribution system but it will have lost and unaccounted for energy.

IV. MARGINAL GENERATION CAPACITY COSTS

The various aspects of marginal generation capacity costs (MGCC) are broken into their specific components below:

A. MGCC Value

Pursuant to the Guidance Decision and the Marginal Cost Settlement Agreement in SDG&E's most recent GRC Phase 2, SDG&E is updating its MGCC values for the Proposed DF Rates to use the most recent Commission Integrated Resource Plan (IRP) for battery energy storage capacity costs. The methodology employed by SDG&E in calculating MGCC can be viewed as a net cost of new entry approach. Historically, MGCC has answered the question "What price would be required to incent a new generator to enter the market and sell firm capacity?" The answer is calculated based on the cost of building the facility less anticipated revenues from California's energy markets. This methodology establishes the long-term MGCC. SDG&E computes MGCC by calculating the cost of building a new lithium-ion, four-hour, energy storage system (ES), including all permitting, financing, and development costs, and deducting expected earnings in California energy and ancillary service markets.

The cost of new entry approach to calculating the MGCC is the same as what SDG&E uses in calculating the GRC Phase 2 generation commodity costs, which SDG&E was specifically ordered to update pursuant to the GRC Phase 2 decision.[5] It is reasonable for SDG&E to use the same methodology as its GRC Phase 2, but with updated values.

[5] D.25-09-006 at 24 (". . . SDG&E is required to update marginal commodity costs for purposes of future dynamic rate proposals . . .").

1. IRP

SDG&E is using the most current IRP data available which is the final IRP inputs and assumptions (I&A).[6] Given ever changing market conditions, SDG&E is using the final inputs and assumptions as they are the most recent data available at the time of its analysis. SDG&E will update its MGCC values annually.[7]

SDG&E selected the mid cost scenario ($142.10/kW-yr) from the final I&A.

2. ACC

The ACC is $176/kW-yr.[8] This is higher than the mid cost scenario of the final I&A ($142.10/kW-yr) utilized by SDG&E. SDG&E chose to use the IRP final I&A mid cost scenario rather than the ACC due to the final IRP being more recent than the 2024 ACC and therefore having access to more recent data. Although the ACC is not being used, it is provided here pursuant to the Guidance Decision.

B. Flexible MGCC

SDG&E values the marginal flexible capacity cost as $0.00. The Guidance Decision allows for IOUs without an existing flexible capacity allocation to either propose a reasonable non-zero percentage or, if proposing zero, "then the IOU must provide analysis and a rationale that supports this determination, a method to address system ramping costs in DF Rate Proposals, and assess the impact on renewable curtailment."[9]

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[6] CPUC, *2024-2026 IRP Cycle Events and Materials*, accessed 5/7/2026, *available at:* https://www.cpuc.ca.gov/industries-and-topics/electrical-energy/electric-power-procurement/long-term-procurement-planning/2024-26-irp-cycle-events-and-materials. *See also*, Filing Requirements Analysis Materials, RESOLVE Workbooks and Public Case Results Viewers.

[7] Guidance Decision, OP 4 at 146 -147.

[8] CPUC, *DER Cost-Effectiveness*, accessed 11/24/2025, 2024 ACC Electric Model v1b, Generation Capacity Tab, cell F4, *available at:* https://www.cpuc.ca.gov/industries-and-topics/electrical-energy/demand-side-management/energy-efficiency/der-cost-effectiveness.

[9] Guidance Decision, COL 10(b) at 140.

Flexible capacity is the ability to provide needed capacity during 3-hour ramping periods. Marginal flexible capacity costs are the cost of providing an incremental unit of flexible capacity. SDG&E uses the process provided by the CAISO's Final Flexible Capacity Needs Assessment for 2023.[10]

A flexible capacity need was calculated by comparing the 3-hour ramp for forecasted load to the resources that can provide flexible capacity in the San Diego/Imperial Valley region. When the 3-hour ramp exceeds the resources that can provide flexible capacity this would indicate that there is a flexible capacity need. The cost of meeting that need would be the less expensive of either building a new battery storage facility or curtailing solar. Solar curtailments are calculated as the opportunity cost of losing that solar generation on the grid. This means losing the Renewable Energy Credit (REC) value of the green energy and in addition, having to replace the energy at market price with another resource.

In the 2026 load forecast, the 3-hour ramp never exceeded the supply of resources that were able to provide flexible capacity. Therefore, SDG&E values the marginal flexible capacity cost as $0.00. This calculation is also consistent with SDG&E's GRC Phase 2 filing which the Commission agreed should be $0.[11] Specifically, for the purposes of the Guidance Decision, there is no need to develop a method to address the system ramping costs because the resources that can meet the ramp already exist, therefore no incremental or marginal resources need to be procured. Because there are enough system resources to meet the ramp there is no need to curtail renewables to reduce the ramp which means there is no impact on renewable curtailment.

[10] CAISO, *Final Flexible Capacity Needs Assessment for 2023* (May 17, 2022) at 2-4, *available at:* http://www.caiso.com/InitiativeDocuments/Final2023FlexibleCapacityNeedsAssessment.pdf.
[11] D.25-09-006, COL 43 at 92 ("Based on findings from SDG&E, it is reasonable for SDG&E to set the value marginal flexible capacity cost at $0.00.")

C. MGCC Function

SDG&E proposes to use the Top 150 hour approach to apply the MGCC to forecasted system load. The top 150 hours are calculated as the average of the prior three years of CAISO system load top 150th hour. If this averaged 150th hour is exceeded then the MGCC adder will be applied to that hour. This approach is consistent with SDG&E's Schedule VGI and Public GIR. SDG&E acknowledges that the Top 150 hours approach is a functional relationship between peak MGCC price and system load, not net load, which was specified in the Guidance Decision.[12]

However, when the Top 150 hour approach was compared to the Loss of Load Probability (LOLP) function applied to all hours, the results were materially similar, except for revenue collection. The LOLP all hour approach is a function of load that includes renewable and must-take generation which makes it equivalent to net load.[13] The Guidance Decision further requires that the function must not unreasonably impact annual revenue recovery stability and perform across a range of system conditions and years.[14] Additionally, the IOUs price function evaluation should include a comparison of revenue recovery variability with alternative functional approaches.[15] Given that the Top 150 hour and the LOLP function for all hours were similar in their distribution of the hours in which the collection would occur, the Top 150 hour approach was chosen since it is easier to implement because it is already being used for electric vehicle dynamic pricing rates, it balances a strong price signal while maintaining revenue recovery, and because it is averaging the prior three years, it should perform across a range of system conditions. Although the revenue collection is less in the Top 150 hour approach it is

[12] Guidance Decision, COL 7 at 139.
[13] The LOLP function is further detailed in the following section.
[14] Guidance Decision, COL 8 at 139.
[15] *Id.*, COL 9 at 139.

more consistent with current rate design. The revenue collection for either of the LOLP functions would potentially put too much emphasis on the MGCC which could mute the price signal from the MEC and other DF rate components. This could create a DF rate in which the customer only shifts load during the hours when the MGCC is applied or skew the revenue collection to on-peak summer hours creating an unreasonable impact on revenue collection stability.

1. Loss of Load Probability (LOLP) Modeling

SDG&E used Loss of Load Probability (LOLP), which is similar to the Loss of Load Expectation (LOLE), to identify periods with the probability of having a loss of load event. Essentially, it identifies periods with the greatest likelihood of needing additional resources. LOLP is the probability of not meeting load in an hour when key system variables are analyzed stochastically. The analysis provides the probability of the hours with the highest need for new resources given the variable nature of customer demand due to weather and the variable nature of solar and wind energy production.

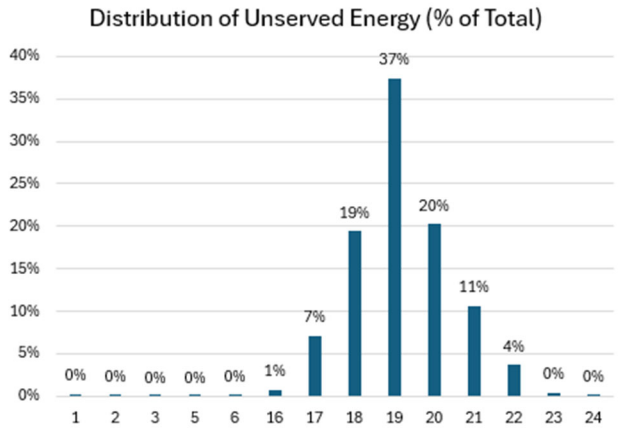
SDG&E determined the LOLP for the SDG&E system using the PLEXOS model, a system dispatch model tailored to the SDG&E system.[16] In order to model real world uncertainties, different load and variable renewable production levels are generated by a stochastic process based on historical data. The PLEXOS model then performs an hourly

[16] The PLEXOS Model is the same production cost model used by SDG&E to forecast procurement costs in the Energy Resource Recovery Account (ERRA) proceeding. The focus in this analysis is on local capacity and the needs for local capacity that can be reduced through the use of appropriate consumer price signals and demand response availability periods to provide incentives for load modification. The PLEXOS model accommodates detailed hour-by-hour simulation of the operations of electric systems. It considers a complex set of generation operating constraints to simulate the least-cost operation of the system. The model's unit commitment and dispatch logic is designed to mimic "real world" power system hourly operation, minimizing system production cost, enforcing the constraints specified for the system, generation stations, associated transmission, fuel, etc.

economic dispatch of generation resources against loads for each hour of the year. By running multiple iterations of the model, a probability distribution of hours with relative expected loss of load can be developed.

The results of the modeling can be seen in the below chart.

Chart JDT-1: Unserved Load by Hour as a Percentage of the Total



The on-peak hours (4 p.m. – 9 p.m., which correspond to Hour Ending 17 and 21 on Chart JDT-1) account for almost 95% of all of the unserved energy. It is also important to note that the only months with unserved energy were July, August, September and October, which align with SDG&E's summer months definition of June - October. Thus, the greatest risk of a loss of load event is during summer on-peak hours.

2. Function Selection

Based on the LOLP analysis performed in Section 1 above, SDG&E applied two linear functions of system load to summer on peak hours and all hours. Due to the nature of the LOLP analysis which already accounts for renewables, essentially treating them as must-take resources, this is the equivalent of using the net load. SDG&E based a LOLP derived function which accounts for renewables to apply to system load. This is sufficient to account for the net load

since using a function based on netting renewables to apply to net load would be over counting the impact of renewables to the MGCC.

Per the Guidance Decision, SDG&E considered multiple functional approaches: an LOLP function limited to only the summer on-peak hours; an LOLP function that is applied to all hours; and a methodology similar to the SDG&E tariff for Vehicle Grid Integration (VGI) and Public Grid Integrated Rate (GIR) that considers a 3-year historical average of the top 150th hour.[17] The Top 150 hours are determined by averaging the top 150th hour of three years of system load and then using that as a threshold for hourly forecasted system load. All of these approaches are functions of system load.

The revenue collection impacts from all three approaches are below.

Table JDT-1: MGCC Approaches[18]

Approach	Marginal Capacity Rate Revenue	# of hrs	% of hrs	% On-Peak	% Off-Peak	% Super Off-Peak
LOLP Function, Summer On-Peak	$ 415,531,079	236	2.69%	100.00%	0.00%	0.00%
LOLP Function, All Hours	$ 631,158,190	419	4.77%	65.84%	28.73%	5.43%
Top 150	$ 55,088,095	156	1.78%	64.74%	29.80%	5.46%

It is important to note that none of the approaches, including the LOLP applied to all hours or the Top 150 hour, resulted in any winter MGCC allocations. The Top 150 hour approach actually yielded more than 150 hours which is not surprising since it is expected that there is some deviation depending on the weather of the year in question versus the weather of the three averaged years. The Top 150 hour approach had lower marginal cost revenue collected as the LOLP functions for all hours. This is due to the Top 150 hour approach being an all-or-

[17] Guidance Decision, COL 9 at 139.
[18] This chart was updated as part of the June 1, 2026 revision to this testimony to account for use of the IRP data.

nothing application of the MGCC, i.e. either the load threshold is met or it is not. In fact, the hours in which Top 150 hour approach is applied yielded almost exactly the same hours as the LOLP function for all hours except for applying to less hours. Because the Top 150 hour approach applies to less hours it provides a more stable and balanced revenue recovery between the MGCC and the MEC.

The April 1, 2026 authorized revenue requirement for the commodity is$565,513,570.[19] This revenue requirement includes the MEC, MGCC and the non-marginal costs which means that the LOLP for all hours function is collecting more from MGCC than the entire commodity revenue requirement, and the LOLP for summer on-peak is collecting 73% of the total commodity revenue requirement. Because of this, SDG&E selected the Top 150 hour approach since it is similar to the hours applied to the LOLP function for all hours but has many other advantages such as having a more stable revenue collection, ease of implementation and being the easiest to understand for customers. Rate design must balance multiple objectives that include but are not limited to, revenue collection, providing strong price signals to encourage flexibility, ease of implementation, and customer understanding. The Top 150 hour approach also has the benefit of providing a consistently high capacity value to encourage customers to shift load.

In addition, the Top 150 hour approach is a three-year average so it complies with the decision in that it will provide revenue recovery stability and can perform across a range of system conditions and years. It is not as volatile since it is less subject to load deviations (either on the high side or the low side) that could impact revenue collection. The MGCC values are presented in the below table:

[19] Advice Letter (AL) 4791-E, and AL 4791-E-A, effective April 1, 2026.

Table JDT-2: MGCC Values in Cents/kWh

Class	MGCC Hourly Adder
Residential	112.83
TABLE DELETED	
Medium Commercial	204.81
Large Commercial and Industrial	143.11
Agriculture	182.31

Class	MGCC Hourly Adder
Residential	112.83
Small Commercial	97.25
Medium Commercial	204.81
Large Commercial and Industrial	143.11
Agriculture	188.35

V. NON-MARGINAL GENERATION COMMODITY COSTS

SDG&E proposes an Equal Percent of Marginal Cost (EPMC) factor to account for non-marginal costs that would be applied to the MEC.[20] The MGCC is already calculated from the capacity share of generation revenue so there is no need to apply an EPMC factor.[21] Using EPMC ensures that all revenues are collected from the Proposed DF Rates. Without an adjustment to collect non-marginal costs, the Proposed DF Rates would undercollect which would create a cost shift.

The Guidance Decision also directs the IOUs "to provide a detailed accounting of the elements comprising non-marginal generation costs, describe how revenues associated with those costs have evolved over time, and identify the long-term cost-drivers of non-marginal generation costs in their DF Rate Proposals."[22] SDG&E provided an accounting for the non-

[20] Guidance Decision, COL 19 at 141-142.
[21] The MGCC includes class specific over/under collections.
[22] *Id*., COL 20 at 142.

marginal generation costs. SDG&E's generation costs are primarily recovered through the Energy Resource Recovery Account (ERRA) proceeding and are not normally broken out by marginal and non-marginal costs.[23] The non-marginal costs can be extrapolated by using the EPMC factors in prior GRC Phase 2 proceedings, as seen in the below table:

Table JDT-3: Generation Costs

Rate Component (w/ FF&U)	2015	2016	2017	2018	2019	2020	2021	2022	2023	2024	2025	2026
Marginal Costs	$ 1,958,966	$1,697,504	$1,022,767	$1,067,284	$ 951,659	$1,001,621	$1,119,543	$ 771,455	$547,242	$378,738	$422,859	$401,929
Non-Marginal Costs	$ (127,333)	$ (110,338)	$ 652,525	$ 680,927	$ 607,159	$ 407,660	$ 455,654	$ 313,982	$222,727	$154,146	$172,104	$163,585
EPMC	0.935	0.935	1.638	1.638	1.638	1.407	1.407	1.407	1.407	1.407	1.407	1.407
Total Generation Costs	$ 1,831,633	$1,587,166	$1,675,292	$1,748,211	$1,558,818	$1,409,281	$1,575,197	$1,085,437	$769,969	$532,885	$594,963	$565,514

Notes:
All Dollars are in $1,000s
Years 2015-2025 are based on the Consolidated Filing, 2026 is based on 4/1/26
Bundled only, excluding undercollections

SDG&E agrees with the CPUC's 2025 SB 695 Report that bundled generation revenue "is significantly influenced by pricing in the wholesale electricity market and by long-term contracts with private generators that reflected market expectations at the time of contract execution."[24] The report goes on to explain that revenue fluctuations are driven by market factors outside the control of the utility such as natural gas costs and renewables.[25] The report is consistent with SDG&E's results where SDG&E is paying higher than market prices for energy due to regulatory requirements like Renewable Portfolio Standards (RPS) and Resource Adequacy (RA). This is also why departed load customers must pay their fair share of these additional costs through the Power Charge Indifference Adjustment (PCIA).[26] SDG&E believes

[23] D.25-12-008 at 18 ("The ERRA provides full recovery of SDG&E's procurement costs, as well as GHG costs, associated with serving its bundled customers. These include expenses associated with California Independent System Operator (CAISO) such as energy and ancillary services load charges, CAISO revenues from utility generation and supply contracts, contract costs, generation fuel costs, and hedging costs.")
[24] CPUC, *2025 Senate Bill 695 Report*, published 09/2025 and accessed 11/26/2025, at 51, *available at:* https://www.cpuc.ca.gov/-/media/cpuc-website/divisions/office-of-governmental-affairs-division/reports/2025/2025-sb-695-report_093025.pdf.
[25] *Id.*
[26] D.25-12-008 at 20 ("The PCIA charge is intended to ensure that any above-market costs of electric resources procured by SDG&E on behalf of its customers that later switch to another provider are not transferred to its remaining electric supply customers.")

that regulatory requirements like RPS and RA will continue to be long-term cost-drivers of generation non-marginal costs.

VI. SUMMARY AND CONCLUSION

SDG&E recommends that the Commission approve the proposed generation rate design for SDG&E's Proposed DF Rates, as described above. This proposed rate design was based on recovery of SDG&E's authorized generation commodity revenues used to develop the illustrative commodity rates. If this rate design is adopted, the MGCC rates and EPMC implemented for dynamic pricing customers will be updated to reflect recovery of SDG&E's generation commodity capacity revenues adopted at the time of implementation.

This concludes my prepared revised direct testimony.

VII. WITNESS QUALIFICATIONS

My name is Jeff DeTuri. My business address is 8315 Century Park Court, San Diego, CA 92123. I am employed by SDG&E and my current title is Senior Supervisor - Rates in the Customer Pricing Department. My responsibilities include oversight of development of real-time pricing strategies and analysis needed for the development of electric rates. I joined SDG&E in August 2003 and have held various positions with increasing levels of responsibility within San Diego Gas & Electric. Prior to joining SDG&E, I worked as an accounting professional for various companies throughout San Diego County. I received a Bachelor of Accountancy degree and a Master of Business Administration from the University of San Diego.

I have previously testified before the California Public Utilities Commission.