Application of San Diego Gas & Electric Company (U 902 E) for Authority to Update Marginal Costs, Cost Allocation, and Electric Rate Design.

Application: 23-01-XXX
Exhibit No.: _________

CHAPTER 5

PREPARED DIRECT TESTIMONY OF

JEFF DE TURI

ON BEHALF OF SAN DIEGO GAS & ELECTRIC COMPANY

*****REDACTED – PUBLIC VERSION*****

BEFORE THE PUBLIC UTILITIES COMMISSION
OF THE STATE OF CALIFORNIA

JANUARY 17, 2023

SDGE™

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PREPARED DIRECT TESTIMONY OF

JEFF DE TURI

(CHAPTER 5)

I. PURPOSE AND OVERVIEW

The purpose of my testimony is to provide the illustrative marginal cost study as well as the cost basis for the illustrative allocation of commodity costs and ongoing Competition Transition Charge (CTC) costs to San Diego Gas & Electric Company's (SDG&E) customer classes. Marginal commodity costs are the incremental electric commodity costs incurred on behalf of utility customers and are composed of marginal energy costs (MEC) and marginal generation capacity costs (MGCC), including marginal flexible capacity costs. Marginal energy costs are the added energy costs incurred to meet electricity consumption. Marginal generation capacity costs are the added costs incurred to meet electric demand. Marginal flexible capacity costs are the added costs incurred to meet the flexible capacity requirements to meet the demand ramp[1] in the greater San Diego region.[2]

My testimony also includes support for changes to SDG&E's current Time of Use (TOU) periods, which is discussed in detail in the prepared direct testimony of SDG&E witness Adam Pierce.[3] The proposed change is to extend the weekday super off-peak TOU period to include 10 AM - 2 PM year-round. The super off-peak period is the time when SDG&E's retail electric rates are lowest. The current, weekday super off-peak TOU period is Midnight to 6 AM and 10

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[1] Demand ramp is the upward or downward slope of the demand curve. It is used to describe how much supply will need to be added over a prescribed period of time. For flexible capacity it is measured in three-hour increments.

[2] SDG&E is presenting marginal flexible capacity costs pursuant to the 2019 General Rate Case (GRC) Phase 2 Settlement, as adopted by D.21-07-010 (Settlement Agreement), Appendix B, Section 2.2.12 <u>Generation Commodity Cost Study Flexible Capacity</u> at 16.

[3] *See generally* Prepared Direct Testimony of Adam Pierce on Behalf of SDG&E (Chapter 1) (January 17, 2023).

AM - 2 PM during the months of March and April only. This testimony provides the results of the Loss of Load Expectation (LOLE) analysis and Deadband Tolerance analysis supporting the proposed TOU periods.

Finally, my testimony will present SDG&E's analysis of net energy metering (NEM) and non-NEM energy and capacity costs as required by D.21-07-010.

My testimony is organized as follows:

- **Section II – Calculation of Marginal Energy Costs:** MEC are the projected energy costs incurred to meet electricity consumption. Since SDG&E transacts in the California Independent System Operator (CAISO) markets, the MEC are based on forecasted prices from our Production Cost Model (PCM).[4] A Renewable Portfolio Standard (RPS) adder is also included since added load requires added renewable energy under the RPS.[5]

- **Section III – Calculation of Marginal Generation Capacity Costs:** MGCC are the added costs incurred to meet electric demand. MGCC are calculated based on long-term considerations and are based on the net cost of new entry of an energy storage unit, the long-term cost of adding new capacity. This amount is equal to the fixed costs of an energy storage unit less expected revenues from energy and ancillary service markets.

- **Section IV – Calculation of Marginal Flexible Capacity Costs:** Marginal flexible capacity costs are the added costs of meeting the ramp. These costs can be calculated as the cost of building a new unit to provide flexible capacity or the cost of curtailing solar resources to reduce the ramp.[6]

- **Section V – Short-Term vs Long-Term Capacity Costs:** Capacity can either be purchased in the market via short-term bilateral contracts or procured by building or expanding resources which would be long term.

- **Section VI – Commodity Revenue Allocation:** Presents the proposal to use marginal costs coupled with the Equal Percent of Marginal Costs (EPMC)

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[4] Settlement Agreement, Section 2.2.13 Marginal Energy Cost Study Methodology at 16.

[5] Established in 2002 under Senate Bill (SB) 1078, accelerated in 2006 under SB 107 and expanded in 2011 under SB 2 1X. *See* SB 1078, Stats. 2001-2002, Ch. 516 (Cal. 2002); SB 107, Stats. 2005-2006, Ch. 464 (Cal. 2006); SB 2 1X.

[6] SDG&E is presenting marginal flexible capacity costs pursuant to Settlement Agreement, Section 2.2.12 at 16.

methodology to allocate the authorized commodity revenue requirement to each customer class based on the calculated MEC and MGCC in Sections II and III.

- **Section VII – CTC Revenue Allocation:** Presents an updated allocation for CTC revenues.

- **Section VIII – Support of TOU Periods:** Presents the LOLE analysis supporting the change to SDG&E's TOU periods. SDG&E is proposing to extend the weekday super off-peak TOU period to include 10 AM – 2 PM year-round and to maintain the current on-peak period of 4 PM to 9 PM year-round.

- **Section IX – NEM vs Non-NEM:** Presents the analysis of the energy and capacity cost comparison between Net Energy Metering customers and non-Net Energy Metering customers.

- **Section X –Conclusion**

- **Section XI –Witness Qualifications**

My testimony also contains the following attachments:

- **Attachment A – Illustrative Commodity Marginal Costs (CONFIDENTIAL)**

- **Attachment B – Illustrative Commodity Revenue Allocations**

- **Attachment C – Illustrative CTC Revenue Allocations**

- **Attachment D – Illustrative Legacy TOU Marginal Energy Costs**[7]

- **Attachment E - Declaration of Jeff DeTuri Regarding Confidentiality of Certain Data/Documents Pursuant to D.06-06-066, *et.al***

II. CALCULATION OF MARGINAL ENERGY COSTS

MEC reflect expected future energy market conditions and are developed by assessing hourly electricity prices. Since the goal is to forecast future hourly prices, SDG&E used a PCM to forecast hourly prices for 2024 through 2027. SDG&E agreed to consider using PCM in the 2019 GRC Phase 2 Settlement Agreement.[8]

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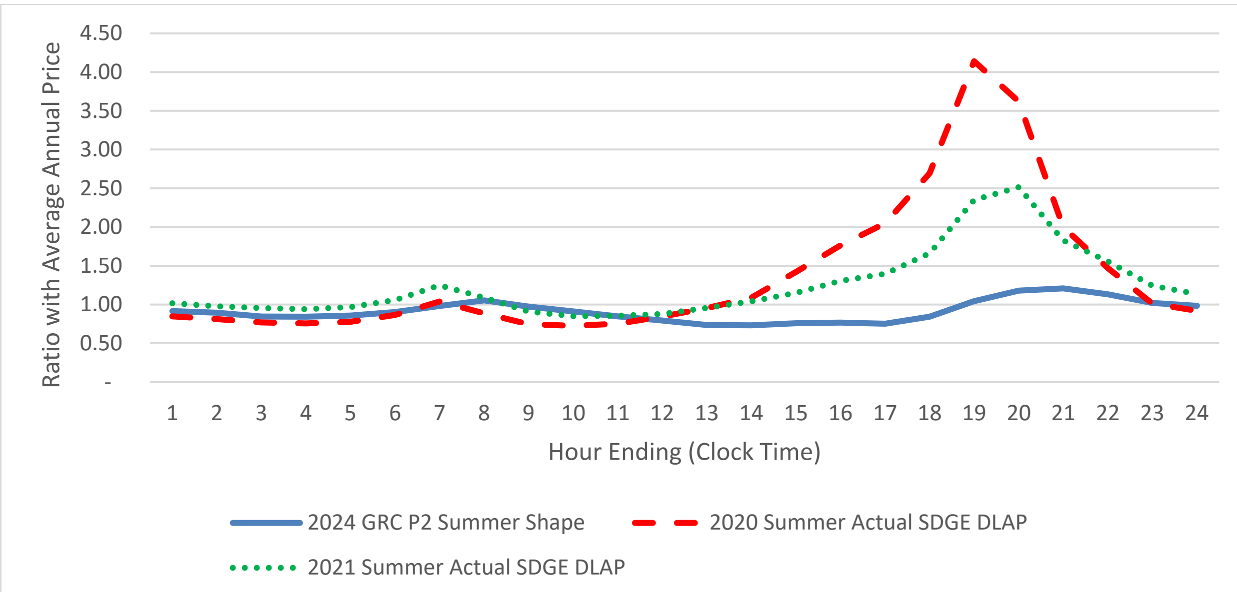
[7] Legacy TOU periods refer to TOU periods implemented prior to December 1, 2017.
[8] Settlement Agreement, Section 2.2.13 at 16; *see also* Rulemaking (R.) 16-02-007, Order Instituting Rulemaking to Develop an Electricity Integrated Resource Planning Framework and to Coordinate and

The SDG&E forecasted 2024 hourly price shape, for summer and winter, respectively, based on the PCM, is illustrated in Chart JND-1 and Chart JND-2 for non-holiday weekdays and is compared to the actual SDG&E Default Load Aggregation Point (DLAP) prices observed in 2020 and 2021, respectively.[9]

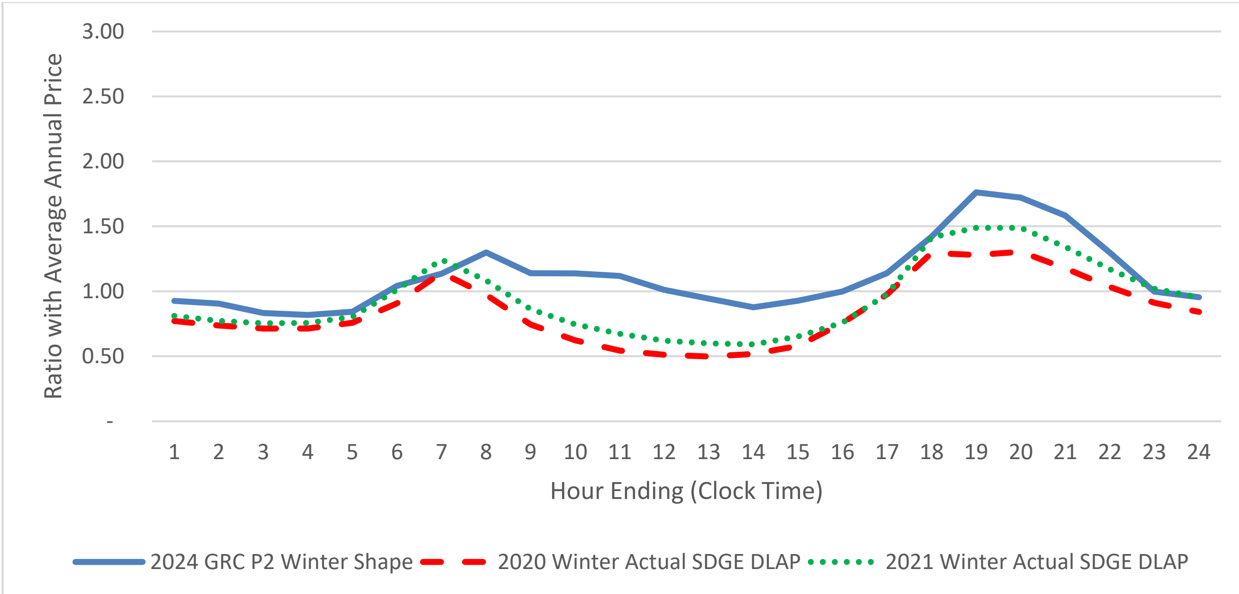
Chart JND-1: Summer Weekday Average Hourly Shape



Refine Long-Term Procurement Planning Requirements (February 11, 2016) (using the same PCM model and many of the same inputs as used here for the Integrated Resource Plan (IRP)).

[9] California ISO OASIS, *Locational Marginal Prices* (LMP), *available at* http://oasis.caiso.com/mrioasis/logon.do. *See* Locational Marginal Prices, From 01/01/2020 To 12/31/2021, Market: DAM, Node: DLAP_SDGE-APND. Note that these prices are not weather adjusted.

Chart JND-2: Winter Weekday Average Hourly Shape



The hourly forecasted prices are then averaged into the appropriate TOU period. The average annual price is calculated to be $39.45 per MWh, or 3.945 cents per kWh. The same calculation is done using legacy SDG&E TOU periods prior to 2017 to develop illustrative SDG&E legacy and two-period TOU marginal energy prices.

The PCM forward prices represent the forecasted wholesale cost of energy in 2024. However, incremental energy will not be purchased entirely from the wholesale market because of California's 44 percent RPS mandate—pursuant to legislation, forty-four percent of incremental energy in 2024 is required to be provided by renewable generation.[10] Thus, in order to capture the full marginal cost of energy, an RPS adder is applied to the wholesale energy prices after they are grouped by SDG&E Standard TOU period. The RPS premium, defined as the "Green Value" and calculated by the California Public Utilities Commission's (Commission

[10] Established in 2002 under Senate Bill (SB) 1078, accelerated in 2006 under SB 107, and expanded in 2011 under SB 2 1X. *See* SB 1078, Stats. 2001-2002, Ch. 516 (Cal. 2002); SB 107, Stats. 2005-2006, Ch. 464 (Cal. 2006); SB 2 1X.

or CPUC) Energy Division, is multiplied by the RPS Target for 2024 of 44% ($0.0137/kWh x 44% = $0.00603/kWh) to determine the RPS adder. The RPS adder is a single value for all hours of the year, as the RPS requirement is an annual target (*i.e.*, it is a % of annual energy sales). The resulting total illustrative marginal energy prices by SDG&E Standard TOU period are shown in Table JND-1 below. The same calculation is done for Legacy TOU prior to 2017 and two-period TOU periods and the resulting total illustrative marginal energy prices of these SDG&E TOU periods are shown in Attachment D, attached herein.

Table JND-1: Total Marginal Energy Prices

SDG&E Proposed TOU Periods	A Wholesale (¢/kWh)	B RPS Adder (¢/kWh)	A+B Total (¢/kWh)
Summer (June 1 - October 31)			
On-Peak: 4 p.m. to 9 p.m. Everyday	3.9821	0.6028	4.5849
Off Peak: All other hours	3.6916	0.6028	4.2944
Super Off Peak: 12 a.m. to 6 a.m., 10 a.m. to 2 p.m. Weekdays and 12 a.m. to 2 p.m. Weekends/Holidays	3.2685	0.6028	3.8713
Winter (November 1 - May 31)			
On-Peak: 4 p.m. to 9 p.m. Everyday	5.8193	0.6028	6.4221
Off Peak: All other hours	4.2492	0.6028	4.8520
Super Off-Peak: 12 a.m. to 6 a.m., 10 a.m. to 2 p.m. Weekdays and 12 a.m. to 2 p.m. Weekends/Holidays	3.4981	0.6028	4.1009
	RPS Premium	$ 13.70	
	RPS %	44%	

The total marginal energy prices shown in Table JND-1 above are input values for the illustrative commodity cost allocation to customer classes presented in Section VI below. As discussed in the prepared direct testimony of SDG&E witness Adam Pierce, SDG&E is not proposing to use the results of its marginal commodity energy cost study to update its commodity rates.

III. CALCULATION OF MARGINAL GENERATION 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 established the long-term MGCC. In this GRC Phase 2, 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. SDG&E evaluated a battery energy storage system per the 2019 GRC Phase 2 Settlement Agreement,[11] and is proposing to use the ES as its marginal resource. Additionally, SDG&E agreed to evaluate, and if reasonable, consider battery/renewable hybrid as a marginal resource. SDG&E determined that a hybrid energy storage and renewable system is an unreasonable marginal resource option because, due to Effective Load Carrying Capability (ELCC) factors, renewables are less effective at providing capacity. SDG&E uses publicly available information to provide a transparent calculation.[12]

Using ES as a marginal resource is reasonable given the Integrated Resource Plan Preferred System Plan shows the new cumulative resource buildout for 2024 having over half of the new resource's MW being battery storage.[13] Thus, SDG&E will likely be procuring the majority of any additional capacity via battery storage. Additionally, in the Commission's

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[11] Settlement Agreement, Section 2.2.11 at 16.

[12] CPUC, 2022 IRP Cycle Events and Materials, available at www.cpuc.ca.gov/industries-and-topics/electrical-energy/electric-power-procurement/long-term-procurement-planning/2022-irp-cycle-events-and-materials.

[13] D.22-02-004 at 87, Table 2. New Resource Buildout of 38 MMT Core (Cumulative MW).

procurement order for mid-term reliability, which covers years 2023-2026, the Commission expressly forbid fossil resources from counting towards capacity procurement.[14] Based on these recent Commission decisions, it is reasonable to switch from using the cost of building a new combustion turbine to the cost of building a new battery storage resource.

To estimate an ES's fixed cost, SDG&E uses the 2022 Integrated Resource Plan RESOLVE Candidate Resource Costs for new-build capacity for a storage lithium-ion battery located in the San Diego region. The annual cost for ES new-build capacity with the energy storage duration costs scaled up to 4 hours is $96.55/kW-yr. The IRP provides the costs as annual costs. Added to that are fixed IRP operations and maintenance costs and various loaders.[15] Finally, the cost is escalated to 2024 dollars using escalators developed in SDG&E's 2024 GRC Phase 1.[16]

To calculate the net cost of capacity, projected market earnings from California's energy markets are deducted from the cost of an ES. SDG&E used the energy arbitrage and ancillary service market profits for the San Diego/Imperial Valley local capacity area from the CAISO Department of Market Monitoring Annual Report on Market Issues & Performance.[17] Because ES has diminishing returns, the ELCC factors must be applied.[18] In addition, all capacity must

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[14] D.21-06-035 at 43 ("Therefore, for purposes of this order, we are not authorizing fossil-fueled resources to count toward the 11,500 MW of total capacity required by this order.").
[15] General Plant, Working Capital, and Administrative and General.
[16] *See* Application (A.) 22-05-016, Prepared Direct Testimony of Scott R. Wilder (Cost Escalation) (May 2022).
[17] California ISO, *2022 Annual Report on Market Issues & Performance* (July 27, 2022) at 89, Table 1.9 New battery energy storage net market revenues by LCA (Scenario 2) (2021).
[18] CPUC, Energy Division Study for Proceeding R.21-10-002, *Loss of Load Expectation and Effective Load Carrying Capability Study Results for 2024* (February 18, 2022) at 26, Table 18.

be scaled up for the Planning Reserve Margin.[19] The resulting MGCC calculation is shown in Table JND-2 below.

Table JND-2: MGCC

Marginal Generation Capacity Cost		
		2024 $/kW-yr
Marginal Cost of a lithium-ion battery storage unit		$ 136.18
Less: Energy market earnings	$115.33	
Subtotal Generation Capacity Costs		$ 20.85
Add: Effective Load Carrying Capacity	$ 6.46	
Add: Planning Reserve Margin	$ 4.64	
Total Marginal Generation Capacity Cost		$ 31.95

The MGCC is an input for the illustrative commodity cost allocation to customer classes presented in Section VI. The prepared direct testimony of SDG&E witness Ray C. Utama (Chapter 2) discusses SDG&E's proposals for customer class revenue allocations.

SDG&E used LOLE results presented in Section VIII for illustrative generation capacity cost allocation. This LOLE approach is an accepted methodology to allocate generation capacity needs to months, days, and hours and is consistent with SDG&E's previous approach in the 2019 GRC Phase 2.[20] SDG&E proposes to continue basing commodity capacity allocation on the top 100 hours of forecasted need. Using a weighting of the top 100 hours and forecasted load,

[19] D.22-06-050, OP 8 at 125.
[20] A.19-03-002, Second Revised Prepared Direct Testimony of Benjamin A. Montoya on Behalf of SDG&E (Chapter 6) (January 15, 2020) at BAM-8.

SDG&E allocated capacity to seasons, days (weekdays/weekends), hours, and TOU periods as shown in Table JND-3 below.

Table JND-3: Top 100 Hour Loss of Load Probability (LOLP)

Weighted LOLP by TOU Period		
SDG&E Proposed TOU Periods	**Summer**	**Winter**
On-Peak: 4 p.m. to 9 p.m. Everyday	93.00%	0.00%
Off Peak: All other hours	7.00%	0.00%
Super Off Peak: 12 a.m. to 6 a.m., 10 a.m. to 2 p.m. Weekdays and 12 a.m. to 2 p.m. Weekends/Holidays	0.00%	0.00%
Total	100.00%	0.00%

As discussed in the prepared direct testimony of SDG&E witness Adam Pierce (Chapter 1), SDG&E is not proposing to use its marginal generation commodity cost study to inform its commodity rate design.[21]

IV. CALCULATION OF MARGINAL FLEXIBLE CAPACITY COSTS

Pursuant to the 2019 GRC Phase 2 Settlement Agreement, SDG&E agreed to evaluate flexible capacity as a marginal cost component.[22] Flexible capacity is the ability to provide needed capacity during 3-hour ramping periods. SDG&E uses the process provided by the CAISO's Final Flexible Capacity Needs Assessment for 2023.[23] Marginal flexible capacity costs are the cost of providing an incremental unit of flexible capacity.

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[21] *See* Prepared Direct Testimony of Adam Pierce on Behalf of SDG&E (Chapter 1) (January 17, 2023) at Section VI.
[22] Settlement Agreement, Section 2.2.12 at 16.
[23] CAISO, Final Flexible Capacity Needs Assessment for 2023 (May 17, 2022) at 2-4, available at http://www.caiso.com/InitiativeDocuments/Final2023FlexibleCapacityNeedsAssessment.pdf.

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 2024-2027 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.

V. SHORT-TERM VS LONG-TERM CAPACITY COSTS

Pursuant to the 2019 GRC Phase 2 Settlement Agreement, SDG&E agreed to consider the mixed short-run and long-run cost methodology for marginal generation capacity.[24] Given recent procurement orders from the Commission[25] and reliability concerns,[26] the need is to procure new or incremental resources, not to contract with existing resources. As the Commission states in the Administrative Law Judge's Ruling on Staff Paper on Procurement Program and Potential Near-Term Actions to Encourage Additional Procurement "the clear collective trend points towards increasing demand for clean electricity and increasing need for additional resources."[27] In addition to the recent procurement orders, there is still a need to

[24] Settlement Agreement, Section 2.2.14 at 16.
[25] D.19-11-016 at 34, ordered 3,300 MW and D.21-06-35 at 43, ordered 11,500 MW.
[26] *See* D.21-12-015 at 2.
[27] R.20-05-003, Administrative Law Judge's Ruling on Staff Paper on Procurement Program and Potential Near-Term Actions to Encourage Additional Procurement (September 8, 2022) at 8.

procure roughly 35,000 MW of new resources by 2030 statewide.[28] The recent procurement orders account for almost half of the needed procurement by 2030. Again, the Commission says it best, "Thus, it is imperative that LSEs continue to procure, both to meet these needs in the next decade, in advance of any additional procurement requirements from the Commission, as well as due to the potential for some projects currently in development not to reach commercial operation."[29]

In the short term, after factoring in the Commission ordered procurement,[30] SDG&E is long capacity due to load departure.[31] There is no short-term capacity need (through 2027) so there is no reason to calculate a short-term capacity cost.

VI. COMMODITY REVENUE ALLOCATION

SDG&E is proposing to use the System Average Percent Change (SAPC) methodology for commodity revenue allocation purposes. SDG&E is not proposing to update its commodity revenue allocations based on the commodity cost study presented here.[32]

Under SDG&E's illustrative cost-based commodity revenue allocation, the authorized commodity revenue requirement is allocated among customer classes based on the illustrative marginal generation capacity and energy revenue cost responsibilities by customer class. The unit marginal generation capacity costs and marginal energy costs, presented in Sections II and

[28] D.22-02-004, at 87, Table 2, New Resource Buildout of 38 MMT Core (Cumulative MW).
[29] R.20-05-003, Administrative Law Judge's Ruling on Staff Paper on Procurement Program and Potential Near-Term Actions to Encourage Additional Procurement (September 8, 2022) at 9.
[30] D.19-11-016 at 34, ordered 3,300 MW and D.21-06-35 at 43, ordered 11,500 MW.
[31] By the end of 2023, SDG&E expects that more than 78% of its total electric customer meters will be served by a Community Choice Aggregation for their electric commodity.
[32] *See* Prepared Direct Testimony of Adam Pierce on Behalf of SDG&E (Chapter 1) (January 17, 2023) at Section VI.

III above, are multiplied by the appropriate cost drivers to develop the illustrative marginal commodity revenue allocations by customer class.

Illustrative marginal energy cost revenues by customer class are developed by multiplying the applicable marginal energy prices ($/kWh) by the 2024 forecasted TOU energy usage in each SDG&E Standard TOU period for each customer class. The same is done for legacy SDG&E TOU periods prior to 2017 and the two period TOU for each customer class.

Illustrative marginal generation capacity cost revenues by customer class are developed by multiplying the unit MGCC ($/kW-year) by each class's estimated contribution to total bundled load based on the top 100 hours with the highest expected need for new resources, as described in Section III above.

The sum of the illustrative marginal generation capacity costs and marginal energy cost revenues is the marginal commodity cost revenues. This is used to determine the illustrative commodity EPMC allocation factor, defined as the commodity revenue requirement divided by the marginal commodity cost revenues. The EPMC allocation factor is then used to scale the marginal commodity cost revenues to ensure that the sum equals the authorized commodity revenue requirement.[33] The illustrative EPMC rates and resulting commodity class allocations are shown in Attachment A and Attachment B, respectively.

VII. CTC REVENUE ALLOCATION

CTC revenues are historically allocated based on the "Top 100 hours" allocation methodology, as adopted by the Commission in Decision 00-06-034. The prepared direct testimony of SDG&E witness Ray C. Utama discusses SDG&E's revenue allocation proposal for

[33] Based on rates effective June 1, 2022 pursuant to Advice Letter (AL) 4004-E.

CTC.[34] Here, SDG&E presents illustrative allocations based on updated top 100-hour data consistent with the method used in the previous GRC.[35] The most recent three years available, 2019-2021, were used to allocate the illustrative CTC revenue requirement. The "Top 100 hours" methodology allocates revenues based on each customer class's contribution to the top 100 hours of system load during a given annual period. The resulting illustrative CTC class allocations are shown in Attachment C.

VIII. SUPPORT OF TOU PERIODS

Current Standard TOU periods were approved in D.17-08-030 and implemented on December 1, 2017. This section provides an evaluation of SDG&E's TOU periods using two different methods: a LOLE analysis, used to support the current TOU periods adopted in the D.17-08-030, and the Deadband Tolerance methodology, approved through advice letter.[36]

LOLE Analysis: This analysis identifies periods with the greatest likelihood of having a loss of load event. Another way of looking at it is that it identifies periods with the greatest likelihood of needing additional resources. LOLE is the probability of not meeting load in an hour when key system variables are analyzed stochastically. The analysis provides the expectation 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.

[34] Prepared Direct Testimony of Ray Utama on Behalf of SDG&E (Chapter 2) (January 17, 2023) at RU-6.
[35] A.19-03-002, Second Revised Prepared Direct Testimony of Benjamin A. Montoya on Behalf of SDG&E (Chapter 6) (January 15, 2020) at BAM-10.
[36] AL 3064-E/E-A, approved and effective January 2, 2019.

SDG&E determined the LOLE for the SDG&E system using the PLEXOS model, a system dispatch model tailored to the SDG&E system.[37] 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 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.

Available generation resources in the analysis include generation units (both new renewable and conventional generation) that currently exist or are expected to be constructed by 2024 in the San Diego Greater Reliability area (both SDG&E service area and Imperial Valley).[38] SDG&E is unique in that local capacity is defined in both the combined San Diego Greater Reliability area, which includes generation from the Imperial Valley, and the San Diego sub-area, which is included in the San Diego Greater Reliability area. The LOLE analysis for San Diego Greater Reliability area was 0 across all hours of the test year. The LOLE for the San Diego sub-area was positive. Accordingly, because the San Diego Greater Reliability area has zero likelihood of not meeting load, no additional analysis was conducted, and the LOLE analysis is limited to the San Diego sub area. Importantly, the resulting analysis is not a

[37] 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 in TOU periods 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.
[38] SDG&E used the same resource assumptions used in the IRP.

measure of need for new capacity, but rather an indication of which hours of the year would experience the highest likelihood of a loss of load.

Chart JND-3 and Chart JND-4 below are a comparison of relative LOLE results for local capacity in the San Diego sub-area for 2024 and 2027. The results show a relative need for capacity or greater likelihood of loss of load during SDG&E's current and proposed on-peak TOU period. Additionally, the results illustrate that the current TOU periods are in alignment with the hours of relative capacity need.

Chart JND-3: 2024 Relative Loss of Load Expectation for the San Diego Local Capacity Area by Hour

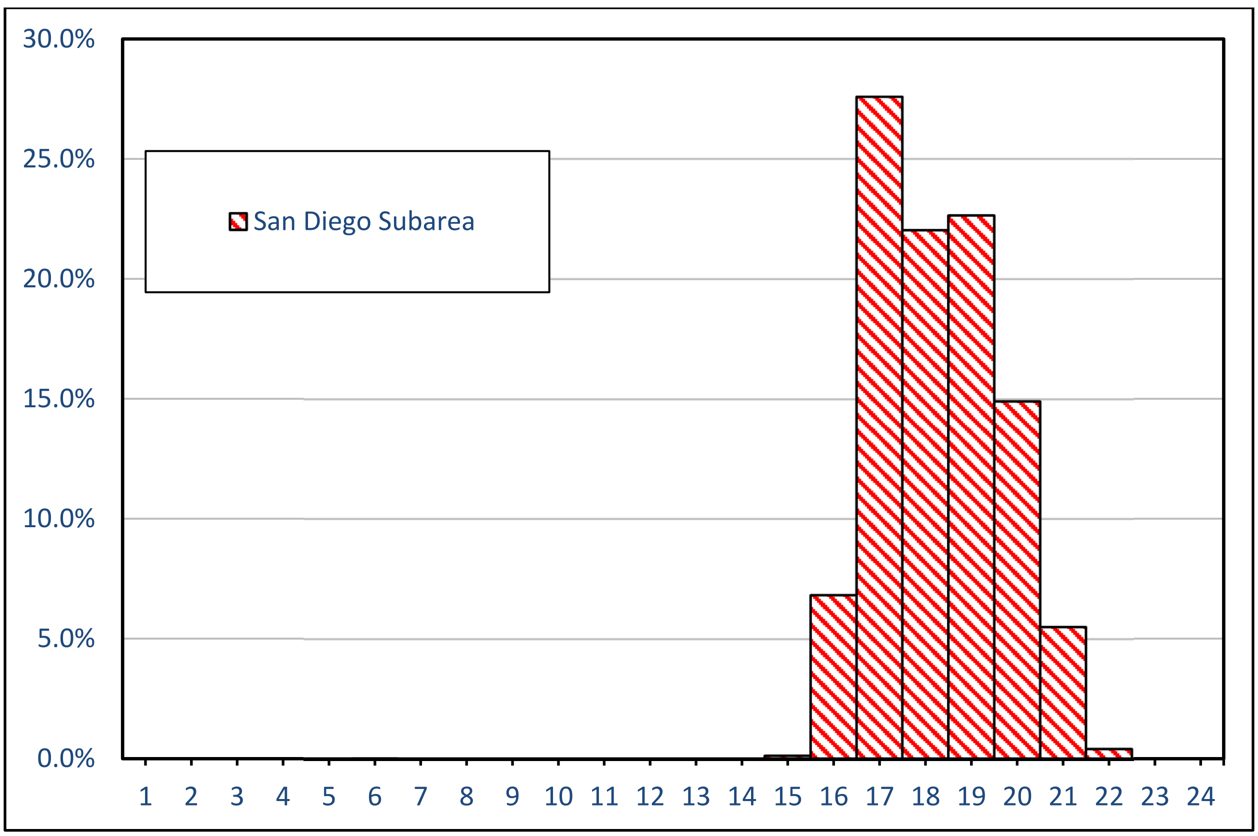
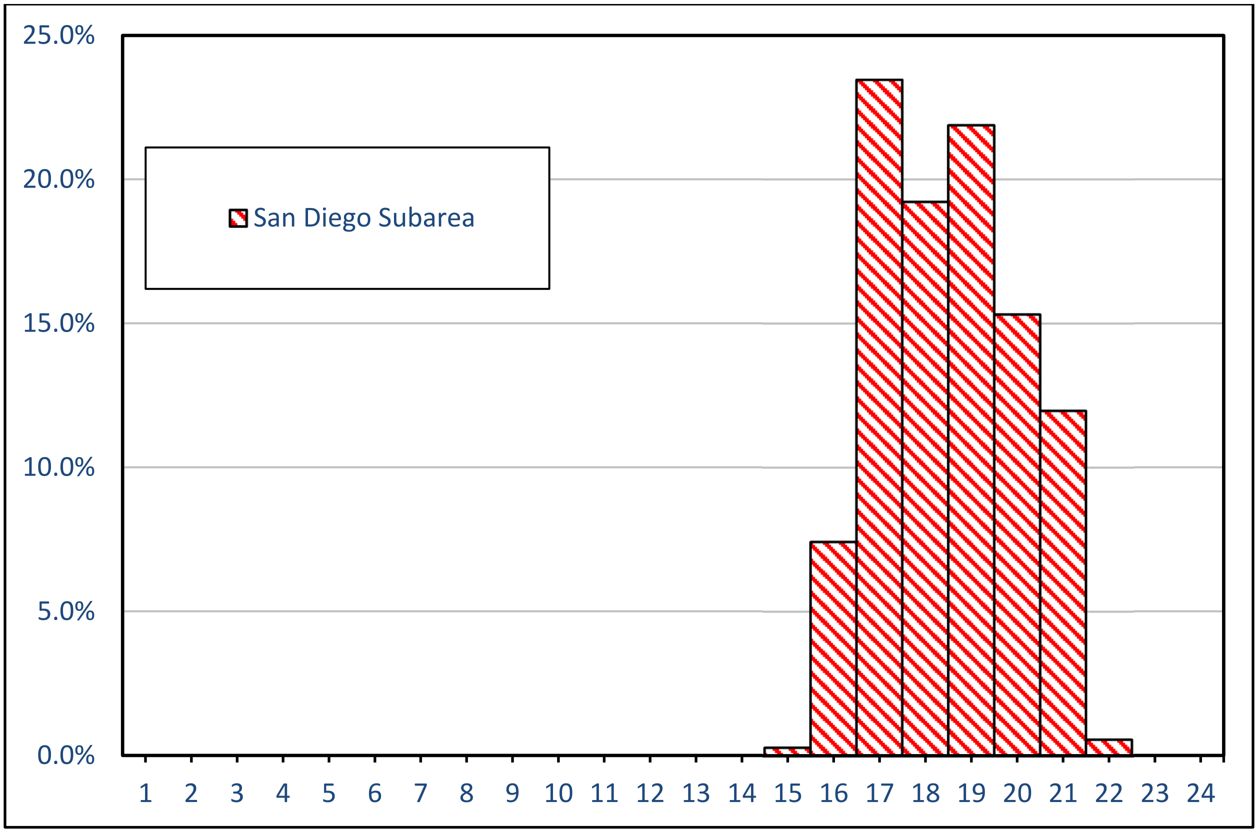


Chart JND-4: 2027 Relative Loss of Load Expectation for the San Diego Local Capacity Area by Hour



Deadband Tolerance Methodology: Per Resolution E-4948, SDG&E will utilize a Deadband Tolerance methodology approved in AL 3064-E/E-A that compares its top 100 hours with existing TOU periods to determine if a proposal to update TOU periods is warranted. This analysis utilizes forecasted marginal energy and capacity costs. SDG&E's approved methodology utilizes a 7.5 percent differential as a trigger; the deadband will be considered exceeded when there is a decline of at least 7.5 percent in the number of top 100 hours that fall within the summer peak and off-peak period, or a decline of at least 7.5 percent in the number of 100 lowest hours that fall within the winter off-peak and super-off-peak periods. When the trigger is exceeded, then a change to the Base TOU periods and related rate designs prior to five years since the last change in TOU periods will be deemed appropriate.[39]

The top 100 hours based on the TOU periods from the 2019 GRC Phase 2 were compared to the TOU periods proposed in this proceeding. In the analysis, all top 100 hours occurred within the SDG&E summer on-peak TOU period of 4 PM to 9 PM. The 100 lowest hours were also compared. All 100 lowest hours occurred within the SDG&E current standard super off-peak period (midnight-to-6AM year-round *and* 10AM-to-2PM March and April) or the proposed super off-peak period (current standard super off-peak + 10AM-to-2PM for the 10 remaining months of the year). This supports SDG&E's proposal to extend the March/April 10AM to 2PM weekday super off-peak period to all months of the year. For both the current and proposed TOU periods, the trigger threshold was not met, therefore SDG&E's current and proposed TOU periods are appropriate and reasonable.

IX. NEM VERSUS NON-NEM

Pursuant to the 2019 GRC Phase 2 Settlement Agreement, SDG&E agreed to study the effects of solar customers' usage and generation profiles on SDG&E's marginal costs.[40] To calculate cost impacts, SDG&E used three years of historical data to create a load profile for NEM delivered energy, NEM received energy, and non-NEM delivered energy. Delivered energy is energy that SDG&E delivers to a customer at the meter. Received energy refers to energy that is exported to the grid by a customer generator. These profiles were then applied to the 2024 load forecast to approximate 2024 NEM delivered, NEM received, and non-NEM delivered energy. The forecasted costs from the marginal energy and marginal generation

[39] AL 3064-E/ E-A at 1-2.
[40] *See* Settlement Agreement, Section 2.2.6 at 13.

capacity, as developed in Sections II and III, was then multiplied by the forecasted load to develop a 2024 forecasted cost study of NEM delivered, NEM received, and non-NEM delivered energy. NEM received energy must be netted with NEM delivered energy to show an aggregated NEM cost. This is appropriate since NEM received energy is providing a benefit to the grid in that it is reducing capacity costs and energy costs, assuming that energy prices are positive. When energy prices are negative by more than the capacity costs, NEM received energy is not a benefit, but a cost.

As expected, NEM received energy, or customer generation that was exported to the grid, provided a net benefit, *i.e.*, reduced costs to ratepayers. However, NEM delivered energy (i.e., energy imported by NEM customers) had higher costs to ratepayers than non-NEM delivered energy ($0.0682/kWh for NEM delivered compared to $0.0599/kWh for non-NEM, see Table JND-4) due to the time of day when the energy was imported by NEM customers (see Chart JND-5). This is logical, as most of SDG&E's NEM customers are customer-generators with behind-the-meter solar installations, which provide energy consumed on-site or exported to the grid during daylight hours, but require customers to import energy during the evening and nighttime hours. Netting the benefits from NEM customer's energy received and NEM customer's energy delivered resulted in higher costs for NEM delivered energy than from non-NEM delivered energy (net NEM received and delivered $0.0726/kWh compared to $0.0599/kWh for non-NEM).

Table JND-4: Forecast 2024 Annual Costs for Bundled NEM and non-NEM Customers

	NEM Received	NEM Delivered	Non-NEM	Net NEM	% Diff
MEC/kWh	$ 0.0574	$ 0.0582	$ 0.0512	$ 0.0588	15%
MGCC/kWh	$ 0.0047	$ 0.0099	$ 0.0087	$ 0.0137	57%
Total Cost/kWh	$ 0.0621	$ 0.0682	$ 0.0599	$ 0.0726	21%

Chart JND-5 Forecasted 2024 Annual Hourly Cost/kWh for Bundled NEM and non-NEM Customers

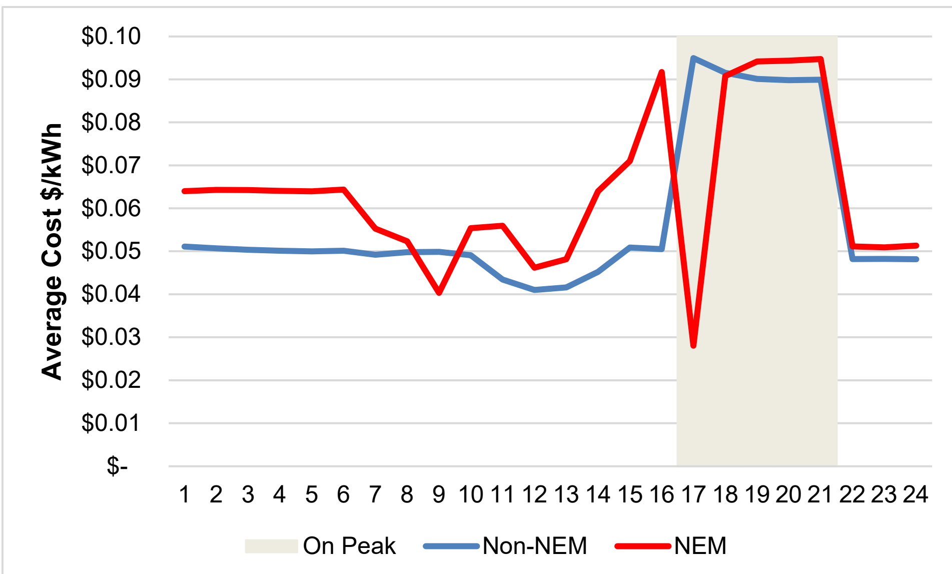


Chart JND-5 shows that NEM costs are typically higher with the exception of an hour in the morning and an hour in the early evening. During the 4-5 PM early evening hour, the average cost per kWh is lower than for non-NEM customers due to high solar generation during that period (on average), which corresponds to the beginning of the on-peak period.

X. SUMMARY AND CONCLUSION

For the foregoing reasons, the illustrative marginal commodity costs presented herein as well as the proposal to use the EPMC revenue allocation methodology to allocate the authorized commodity revenue requirement to customer classes for rate design purposes are reasonable. In addition, SDG&E recommends that the Commission adopt its proposal to update the current base TOU periods.

This concludes my prepared direct testimony.

XI. 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 in the Customer Pricing Department and my current title is Real Time Pricing Manager. My responsibilities include oversight of development of real-time pricing strategies and analysis 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.

ATTACHMENT A

(CONFIDENTIAL)

Illustrative Commodity Marginal Costs

ATTACHMENT A.1

SAN DIEGO GAS & ELECTRIC
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1	**RESIDENTIAL**												1
2	*Secondary*												2
3	**Summer**				[redacted]					[redacted]			3
4	On-Peak Demand	$/kW		2.58528	[redacted]				15.09289	[redacted]			4
5	On-Peak Energy	$/kWh	0.04864		[redacted]			0.28398		[redacted]			5
6	Off-Peak Energy	$/kWh	0.04545	0.00421	[redacted]			0.26537	0.02456	[redacted]			6
7	Super Off-Peak Energy	$/kWh	0.04089	0.00000	[redacted]			0.23872	0.00000	[redacted]			7
8					[redacted]					[redacted]			8
9	**Winter**				[redacted]					[redacted]			9
10	On-Peak Demand	$/kW		0.00000	[redacted]				0.00000	[redacted]			10
11	On-Peak Energy	$/kWh	0.06803		[redacted]			0.39718		[redacted]			11
12	Off-Peak Energy	$/kWh	0.05125	0.00000	[redacted]			0.29917	0.00000	[redacted]			12
13	Super Off-Peak Energy	$/kWh	0.04323	0.00000	[redacted]			0.25240	0.00000	[redacted]			13
14					[redacted]					[redacted]			14
15	**SMALL COMMERCIAL**				[redacted]					[redacted]			15
16	*Secondary*				[redacted]					[redacted]			16
17	**Summer**				[redacted]					[redacted]			17
18	On-Peak Demand	$/kW		3.49025	[redacted]				20.37610	[redacted]			18
19	On-Peak Energy	$/kWh	0.04864		[redacted]			0.28398		[redacted]			19
20	Off-Peak Energy	$/kWh	0.04545	0.00462	[redacted]			0.26537	0.02696	[redacted]			20
21	Super Off-Peak Energy	$/kWh	0.04089	0.00000	[redacted]			0.23872	0.00000	[redacted]			21
22					[redacted]					[redacted]			22
23	**Winter**				[redacted]					[redacted]			23
24	On-Peak Demand	$/kW		0.00000	[redacted]				0.00000	[redacted]			24
25	On-Peak Energy	$/kWh	0.06803		[redacted]			0.39718		[redacted]			25
26	Off-Peak Energy	$/kWh	0.05125	0.00000	[redacted]			0.29917	0.00000	[redacted]			26
27	Super Off-Peak Energy	$/kWh	0.04323	0.00000	[redacted]			0.25240	0.00000	[redacted]			27
28					[redacted]					[redacted]			28
29	*Primary*				[redacted]					[redacted]			29
30	**Summer**				[redacted]					[redacted]			30
31	On-Peak Demand	$/kW		3.47341	[redacted]				20.27783	[redacted]			31
32	On-Peak Energy	$/kWh	0.04841		[redacted]			0.28262		[redacted]			32
33	Off-Peak Energy	$/kWh	0.04526	0.00460	[redacted]			0.26420	0.02684	[redacted]			33
34	Super Off-Peak Energy	$/kWh	0.04073	0.00000	[redacted]			0.23779	0.00000	[redacted]			34
35					[redacted]					[redacted]			35
36	**Winter**				[redacted]					[redacted]			36
37	On-Peak Demand	$/kW		0.00000	[redacted]				0.00000	[redacted]			37
38	On-Peak Energy	$/kWh	0.06772		[redacted]			0.39536		[redacted]			38
39	Off-Peak Energy	$/kWh	0.05104	0.00000	[redacted]			0.29797	0.00000	[redacted]			39
40	Super Off-Peak Energy	$/kWh	0.04308	0.00000	[redacted]			0.25152	0.00000	[redacted]			40

ATTACHMENT A.1

SAN DIEGO GAS & ELECTRIC
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41					[redacted]					[redacted]			41
42	<u>**MEDIUM COMMERCIAL**</u>				[redacted]					[redacted]			42
43	*Secondary*				[redacted]					[redacted]			43
44	**Summer**				[redacted]					[redacted]			44
45	On-Peak Demand	$/kW		3.53583	[redacted]				20.64223	[redacted]			45
46	On-Peak Energy	$/kWh	0.04864		[redacted]			0.28398		[redacted]			46
47	Off-Peak Energy	$/kWh	0.04545	0.00530	[redacted]			0.26537	0.03094	[redacted]			47
48	Super Off-Peak Energy	$/kWh	0.04089	0.00000	[redacted]			0.23872	0.00000	[redacted]			48
49					[redacted]					[redacted]			49
50	**Winter**				[redacted]					[redacted]			50
51	On-Peak Demand	$/kW		0.00000	[redacted]				0.00000	[redacted]			51
52	On-Peak Energy	$/kWh	0.06803		[redacted]			0.39718		[redacted]			52
53	Off-Peak Energy	$/kWh	0.05125	0.00000	[redacted]			0.29917	0.00000	[redacted]			53
54	Super Off-Peak Energy	$/kWh	0.04323	0.00000	[redacted]			0.25240	0.00000	[redacted]			54
55					[redacted]					[redacted]			55
56	*Primary*				[redacted]					[redacted]			56
57	**Summer**				[redacted]					[redacted]			57
58	On-Peak Demand	$/kW		3.51878	[redacted]				20.54267	[redacted]			58
59	On-Peak Energy	$/kWh	0.04841		[redacted]			0.28262		[redacted]			59
60	Off-Peak Energy	$/kWh	0.04526	0.00528	[redacted]			0.26420	0.03080	[redacted]			60
61	Super Off-Peak Energy	$/kWh	0.04073	0.00000	[redacted]			0.23779	0.00000	[redacted]			61
62					[redacted]					[redacted]			62
63	**Winter**				[redacted]					[redacted]			63
64	On-Peak Demand	$/kW		0.00000	[redacted]				0.00000	[redacted]			64
65	On-Peak Energy	$/kWh	0.06772		[redacted]			0.39536		[redacted]			65
66	Off-Peak Energy	$/kWh	0.05104	0.00000	[redacted]			0.29797	0.00000	[redacted]			66
67	Super Off-Peak Energy	$/kWh	0.04308	0.00000	[redacted]			0.25152	0.00000	[redacted]			67
68					[redacted]					[redacted]			68
69					[redacted]					[redacted]			69
70	<u>**LARGE C&I**</u>				[redacted]					[redacted]			70
71	*Secondary*				[redacted]					[redacted]			71
72	**Summer**				[redacted]					[redacted]			72
73	On-Peak Demand	$/kW		3.62936	[redacted]				21.18828	[redacted]			73
74	On-Peak Energy	$/kWh	0.04864		[redacted]			0.28398		[redacted]			74
75	Off-Peak Energy	$/kWh	0.04545	0.00190	[redacted]			0.26537	0.01108	[redacted]			75
76	Super Off-Peak Energy	$/kWh	0.04089	0.00000	[redacted]			0.23872	0.00000	[redacted]			76
77					[redacted]					[redacted]			77
78	**Winter**				[redacted]					[redacted]			78
79	On-Peak Demand	$/kW		0.00000	[redacted]				0.00000	[redacted]			79
80	On-Peak Energy	$/kWh	0.06803		[redacted]			0.39718		[redacted]			80

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81	Off-Peak Energy	$/kWh	0.05125	0.00000	[redacted]			0.29917	0.00000	[redacted]			81
82	Super Off-Peak Energy	$/kWh	0.04323	0.00000	[redacted]			0.25240	0.00000	[redacted]			82
83					[redacted]					[redacted]			83
84	*Primary*				[redacted]					[redacted]			84
85	**Summer**				[redacted]					[redacted]			85
86	On-Peak Demand	$/kW		3.61186	[redacted]				21.08609	[redacted]			86
87	On-Peak Energy	$/kWh	0.04841		[redacted]			0.28262		[redacted]			87
88	Off-Peak Energy	$/kWh	0.04526	0.00189	[redacted]			0.26420	0.01103	[redacted]			88
89	Super Off-Peak Energy	$/kWh	0.04073	0.00000	[redacted]			0.23779	0.00000	[redacted]			89
90					[redacted]					[redacted]			90
91	**Winter**				[redacted]					[redacted]			91
92	On-Peak Demand	$/kW		0.00000	[redacted]				0.00000	[redacted]			92
93	On-Peak Energy	$/kWh	0.06772		[redacted]			0.39536		[redacted]			93
94	Off-Peak Energy	$/kWh	0.05104	0.00000	[redacted]			0.29797	0.00000	[redacted]			94
95	Super Off-Peak Energy	$/kWh	0.04308	0.00000	[redacted]			0.25152	0.00000	[redacted]			95
96					[redacted]					[redacted]			96
97	*Transmission*				[redacted]					[redacted]			97
98	**Summer**				[redacted]					[redacted]			98
99	On-Peak Demand	$/kW		3.45699	[redacted]				20.18196	[redacted]			99
100	On-Peak Energy	$/kWh	0.04633		[redacted]			0.27050		[redacted]			100
101	Off-Peak Energy	$/kWh	0.04336	0.00181	[redacted]			0.25313	0.01057	[redacted]			101
102	Super Off-Peak Energy	$/kWh	0.03905	0.00000	[redacted]			0.22795	0.00000	[redacted]			102
103					[redacted]					[redacted]			103
104	**Winter**				[redacted]					[redacted]			104
105	On-Peak Demand	$/kW		0.00000	[redacted]				0.00000	[redacted]			105
106	On-Peak Energy	$/kWh	0.06487		[redacted]			0.37870		[redacted]			106
107	Off-Peak Energy	$/kWh	0.04895	0.00000	[redacted]			0.28579	0.00000	[redacted]			107
108	Super Off-Peak Energy	$/kWh	0.04133	0.00000	[redacted]			0.24130	0.00000	[redacted]			108
109					[redacted]					[redacted]			109
110	**AGRICULTURE**				[redacted]					[redacted]			110
111	*Secondary*				[redacted]					[redacted]			111
112	**Summer**				[redacted]					[redacted]			112
113	On-Peak Demand	$/kW		5.61565	[redacted]				32.78428	[redacted]			113
114	On-Peak Energy	$/kWh	0.04864		[redacted]			0.28398		[redacted]			114
115	Off-Peak Energy	$/kWh	0.04545	0.00385	[redacted]			0.26537	0.02248	[redacted]			115
116	Super Off-Peak Energy	$/kWh	0.04089	0.00000	[redacted]			0.23872	0.00000	[redacted]			116
117					[redacted]					[redacted]			117
118	**Winter**				[redacted]					[redacted]			118
119	On-Peak Demand	$/kW		0.00000	[redacted]				0.00000	[redacted]			119
120	On-Peak Energy	$/kWh	0.06803		[redacted]			0.39718		[redacted]			120

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121	Off-Peak Energy	$/kWh	0.05125	0.00000	[redacted]			0.29917	0.00000	[redacted]			121
122	Super Off-Peak Energy	$/kWh	0.04323	0.00000				0.25240	0.00000				122
123													123
124	*Primary*												124
125	**Summer**												125
126	On-Peak Demand	$/kW		5.58857					32.62616				126
127	On-Peak Energy	$/kWh	0.04841					0.28262					127
128	Off-Peak Energy	$/kWh	0.04526	0.00383				0.26420	0.02238				128
129	Super Off-Peak Energy	$/kWh	0.04073	0.00000				0.23779	0.00000				129
130													130
131	**Winter**												131
132	On-Peak Demand	$/kW		0.00000					0.00000				132
133	On-Peak Energy	$/kWh	0.06772					0.39536					133
134	Off-Peak Energy	$/kWh	0.05104	0.00000				0.29797	0.00000				134
135	Super Off-Peak Energy	$/kWh	0.04308	0.00000				0.25152	0.00000				135
136													136
137	**LIGHTING**												137
138	*Secondary*												138
139	**Summer**												139
140	On-Peak Demand	$/kW		2.39037					13.95500				140
141	On-Peak Energy	$/kWh	0.04864					0.28398					141
142	Off-Peak Energy	$/kWh	0.04545	0.00027				0.26537	0.00159				142
143	Super Off-Peak Energy	$/kWh	0.04089	0.00000				0.23872	0.00000				143
144													144
145	**Winter**												145
146	On-Peak Demand	$/kW		0.00000					0.00000				146
147	On-Peak Energy	$/kWh	0.06803					0.39718					147
148	Off-Peak Energy	$/kWh	0.05125	0.00000				0.29917	0.00000				148
149	Super Off-Peak Energy	$/kWh	0.04323	0.00000				0.25240	0.00000				149
150													150
151	**TOTAL RATE REVENUE SUMMARY**												151
152					**Energy**	**Capacity**	**Total**			**Energy**	**Capacity**	**Total**	152
153	**RESIDENTIAL**				[redacted]					[redacted]			153
154	**SMALL COMMERCIAL**												154
155	**MEDIUM COMMERCIAL**												155
156	**LARGE C&I**												156
157	**AGRICULTURAL**												157
158	**LIGHTING**												158
159	**TOTAL**												159

ATTACHMENT A.2

SAN DIEGO GAS & ELECTRIC
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1	**<u>RESIDENTIAL</u>**												1
2													2
3	**<u>SMALL COMMERCIAL</u>**												3
4	*Secondary*												4
5	**Summer**				[redacted]	[redacted]	[redacted]			[redacted]	[redacted]	[redacted]	5
6	On-Peak Demand	$/kW		2.06658	[redacted]	[redacted]	[redacted]		10.46942	[redacted]	[redacted]	[redacted]	6
7	On-Peak Energy	$/kWh	0.03884		[redacted]	[redacted]	[redacted]	0.19675		[redacted]	[redacted]	[redacted]	7
8	Semi-Peak Energy	$/kWh	0.04971	0.02196	[redacted]	[redacted]	[redacted]	0.25185	0.11127	[redacted]	[redacted]	[redacted]	8
9	Off-Peak Energy	$/kWh	0.04313	0.00229	[redacted]	[redacted]	[redacted]	0.21850	0.01160	[redacted]	[redacted]	[redacted]	9
10					[redacted]	[redacted]	[redacted]			[redacted]	[redacted]	[redacted]	10
11	**Winter**				[redacted]	[redacted]	[redacted]			[redacted]	[redacted]	[redacted]	11
12	On-Peak Demand	$/kW		0.00000	[redacted]	[redacted]	[redacted]		0.00000	[redacted]	[redacted]	[redacted]	12
13	On-Peak Energy	$/kWh	0.07560		[redacted]	[redacted]	[redacted]	0.38300		[redacted]	[redacted]	[redacted]	13
14	Semi-Peak Energy	$/kWh	0.05365	0.00000	[redacted]	[redacted]	[redacted]	0.27181	0.00000	[redacted]	[redacted]	[redacted]	14
15	Off-Peak Energy	$/kWh	0.04522	0.00000	[redacted]	[redacted]	[redacted]	0.22909	0.00000	[redacted]	[redacted]	[redacted]	15
16					[redacted]	[redacted]	[redacted]			[redacted]	[redacted]	[redacted]	16
17	*Primary*				[redacted]	[redacted]	[redacted]			[redacted]	[redacted]	[redacted]	17
18	**Summer**				[redacted]	[redacted]	[redacted]			[redacted]	[redacted]	[redacted]	18
19	On-Peak Demand	$/kW		2.05571	[redacted]	[redacted]	[redacted]		10.41438	[redacted]	[redacted]	[redacted]	19
20	On-Peak Energy	$/kWh	0.03863		[redacted]	[redacted]	[redacted]	0.19572		[redacted]	[redacted]	[redacted]	20
21	Semi-Peak Energy	$/kWh	0.04948	0.02186	[redacted]	[redacted]	[redacted]	0.25067	0.11074	[redacted]	[redacted]	[redacted]	21
22	Off-Peak Energy	$/kWh	0.04298	0.00228	[redacted]	[redacted]	[redacted]	0.21772	0.01156	[redacted]	[redacted]	[redacted]	22
23					[redacted]	[redacted]	[redacted]			[redacted]	[redacted]	[redacted]	23
24	**Winter**				[redacted]	[redacted]	[redacted]			[redacted]	[redacted]	[redacted]	24
25	On-Peak Demand	$/kW		0.00000	[redacted]	[redacted]	[redacted]		0.00000	[redacted]	[redacted]	[redacted]	25
26	On-Peak Energy	$/kWh	0.07523		[redacted]	[redacted]	[redacted]	0.38114		[redacted]	[redacted]	[redacted]	26
27	Semi-Peak Energy	$/kWh	0.05342	0.00000	[redacted]	[redacted]	[redacted]	0.27061	0.00000	[redacted]	[redacted]	[redacted]	27
28	Off-Peak Energy	$/kWh	0.04507	0.00000	[redacted]	[redacted]	[redacted]	0.22831	0.00000	[redacted]	[redacted]	[redacted]	28
29					[redacted]	[redacted]	[redacted]			[redacted]	[redacted]	[redacted]	29
30	**<u>MEDIUM COMMERCIAL</u>**				[redacted]	[redacted]	[redacted]			[redacted]	[redacted]	[redacted]	30
31	*Secondary*				[redacted]	[redacted]	[redacted]			[redacted]	[redacted]	[redacted]	31
32	**Summer**				[redacted]	[redacted]	[redacted]			[redacted]	[redacted]	[redacted]	32
33	On-Peak Demand	$/kW		2.05172	[redacted]	[redacted]	[redacted]		10.39413	[redacted]	[redacted]	[redacted]	33
34	On-Peak Energy	$/kWh	0.03884		[redacted]	[redacted]	[redacted]	0.19675		[redacted]	[redacted]	[redacted]	34
35	Semi-Peak Energy	$/kWh	0.04971	0.13151	[redacted]	[redacted]	[redacted]	0.25185	0.66626	[redacted]	[redacted]	[redacted]	35
36	Off-Peak Energy	$/kWh	0.04313	0.00244	[redacted]	[redacted]	[redacted]	0.21850	0.01236	[redacted]	[redacted]	[redacted]	36
37					[redacted]	[redacted]	[redacted]			[redacted]	[redacted]	[redacted]	37
38	**Winter**				[redacted]	[redacted]	[redacted]			[redacted]	[redacted]	[redacted]	38
39	On-Peak Demand	$/kW		0.00000	[redacted]	[redacted]	[redacted]		0.00000	[redacted]	[redacted]	[redacted]	39

ATTACHMENT A.2

SAN DIEGO GAS & ELECTRIC
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ILLUSTRATIVE COMMODITY MARGINAL COSTS AND EPMC RATES AND REVENUES, LEGACY TOU - DE TURI (CH. 5)

PRIVILEGED AND CONFIDENTIAL PURSUANT TO P.U.C. CODE 583, 454.5(g), GO 66-C AND D.06-06-066 as needed

Line No.	Description (A)	Unit (B)	Marginal Energy Rate (C)	Marginal Capacity Rate (D)	Marginal Energy Rate Revenue (E)	Marginal Capacity Rate Revenue (F)	Total Marginal Rate Revenue (G)	EPMC Energy Rate (H)	EPMC Capacity Rate (I)	EPMC Energy Rate Revenue (J)	EPMC Capacity Rate Revenue (K)	Total EPMC Rate Revenue (L)	Line No.
40	On-Peak Energy	$/kWh	0.07560		[redacted]			0.38300		[redacted]			40
41	Semi-Peak Energy	$/kWh	0.05365	0.00000				0.27181	0.00000				41
42	Off-Peak Energy	$/kWh	0.04522	0.00000				0.22909	0.00000				42
43													43
44	*Primary*												44
45	**Summer**												45
46	On-Peak Demand	$/kW		2.04093					10.33948				46
47	On-Peak Energy	$/kWh	0.03863					0.19572					47
48	Semi-Peak Energy	$/kWh	0.04948	0.13089				0.25067	0.66311				48
49	Off-Peak Energy	$/kWh	0.04298	0.00243				0.21772	0.01231				49
50													50
51	**Winter**												51
52	On-Peak Demand	$/kW		0.00000					0.00000				52
53	On-Peak Energy	$/kWh	0.07523					0.38114					53
54	Semi-Peak Energy	$/kWh	0.05342	0.00000				0.27061	0.00000				54
55	Off-Peak Energy	$/kWh	0.04507	0.00000				0.22831	0.00000				55
56													56
57	**<u>Large C&I</u>**												57
58	*Secondary*												58
59	**Summer**												59
60	On-Peak Demand	$/kW		2.06088					10.44055				60
61	On-Peak Energy	$/kWh	0.03884					0.19675					61
62	Semi-Peak Energy	$/kWh	0.04971	0.00967				0.25185	0.04897				62
63	Off-Peak Energy	$/kWh	0.04313	0.00087				0.21850	0.00441				63
64													64
65	**Winter**												65
66	On-Peak Demand	$/kW		0.00000					0.00000				66
67	On-Peak Energy	$/kWh	0.07560					0.38300					67
68	Semi-Peak Energy	$/kWh	0.05365	0.00000				0.27181	0.00000				68
69	Off-Peak Energy	$/kWh	0.04522	0.00000				0.22909	0.00000				69
70													70
71	*Primary*												71
72	**Summer**												72
73	On-Peak Demand	$/kW		2.05004					10.38566				73
74	On-Peak Energy	$/kWh	0.03863					0.19572					74
75	Semi-Peak Energy	$/kWh	0.04948	0.00962				0.25067	0.04874				75
76	Off-Peak Energy	$/kWh	0.04298	0.00087				0.21772	0.00439				76
77													77
78	**Winter**												78

ATTACHMENT A.2

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ILLUSTRATIVE COMMODITY MARGINAL COSTS AND EPMC RATES AND REVENUES, LEGACY TOU - DE TURI (CH. 5)

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79	On-Peak Demand	$/kW		0.00000	[redacted]	[redacted]	[redacted]		0.00000	[redacted]	[redacted]	[redacted]	79
80	On-Peak Energy	$/kWh	0.07523		[redacted]	[redacted]	[redacted]	0.38114		[redacted]	[redacted]	[redacted]	80
81	Semi-Peak Energy	$/kWh	0.05342	0.00000	[redacted]	[redacted]	[redacted]	0.27061	0.00000	[redacted]	[redacted]	[redacted]	81
82	Off-Peak Energy	$/kWh	0.04507	0.00000	[redacted]	[redacted]	[redacted]	0.22831	0.00000	[redacted]	[redacted]	[redacted]	82
83					[redacted]	[redacted]	[redacted]			[redacted]	[redacted]	[redacted]	83
84	*Transmission*				[redacted]	[redacted]	[redacted]			[redacted]	[redacted]	[redacted]	84
85	**Summer**				[redacted]	[redacted]	[redacted]			[redacted]	[redacted]	[redacted]	85
86	On-Peak Demand	$/kW		1.95909	[redacted]	[redacted]	[redacted]		9.92485	[redacted]	[redacted]	[redacted]	86
87	On-Peak Energy	$/kWh	0.03692		[redacted]	[redacted]	[redacted]	0.18703		[redacted]	[redacted]	[redacted]	87
88	Semi-Peak Energy	$/kWh	0.04738	0.00921	[redacted]	[redacted]	[redacted]	0.24001	0.04666	[redacted]	[redacted]	[redacted]	88
89	Off-Peak Energy	$/kWh	0.04123	0.00083	[redacted]	[redacted]	[redacted]	0.20888	0.00422	[redacted]	[redacted]	[redacted]	89
90					[redacted]	[redacted]	[redacted]			[redacted]	[redacted]	[redacted]	90
91	**Winter**				[redacted]	[redacted]	[redacted]			[redacted]	[redacted]	[redacted]	91
92	On-Peak Demand	$/kW		0.00000	[redacted]	[redacted]	[redacted]		0.00000	[redacted]	[redacted]	[redacted]	92
93	On-Peak Energy	$/kWh	0.07201		[redacted]	[redacted]	[redacted]	0.36480		[redacted]	[redacted]	[redacted]	93
94	Semi-Peak Energy	$/kWh	0.05119	0.00000	[redacted]	[redacted]	[redacted]	0.25935	0.00000	[redacted]	[redacted]	[redacted]	94
95	Off-Peak Energy	$/kWh	0.04325	0.00000	[redacted]	[redacted]	[redacted]	0.21911	0.00000	[redacted]	[redacted]	[redacted]	95
96					[redacted]	[redacted]	[redacted]			[redacted]	[redacted]	[redacted]	96
97	**AGRICULTURE**				[redacted]	[redacted]	[redacted]			[redacted]	[redacted]	[redacted]	97
98	*Secondary*				[redacted]	[redacted]	[redacted]			[redacted]	[redacted]	[redacted]	98
99	**Summer**				[redacted]	[redacted]	[redacted]			[redacted]	[redacted]	[redacted]	99
100	On-Peak Demand	$/kW		2.65924	[redacted]	[redacted]	[redacted]		13.47189	[redacted]	[redacted]	[redacted]	100
101	On-Peak Energy	$/kWh	0.03884		[redacted]	[redacted]	[redacted]	0.19675		[redacted]	[redacted]	[redacted]	101
102	Semi-Peak Energy	$/kWh	0.04971	0.02829	[redacted]	[redacted]	[redacted]	0.25185	0.14333	[redacted]	[redacted]	[redacted]	102
103	Off-Peak Energy	$/kWh	0.04313	0.00209	[redacted]	[redacted]	[redacted]	0.21850	0.01060	[redacted]	[redacted]	[redacted]	103
104					[redacted]	[redacted]	[redacted]			[redacted]	[redacted]	[redacted]	104
105	**Winter**				[redacted]	[redacted]	[redacted]			[redacted]	[redacted]	[redacted]	105
106	On-Peak Demand	$/kW		0.00000	[redacted]	[redacted]	[redacted]		0.00000	[redacted]	[redacted]	[redacted]	106
107	On-Peak Energy	$/kWh	0.07560		[redacted]	[redacted]	[redacted]	0.38300		[redacted]	[redacted]	[redacted]	107
108	Semi-Peak Energy	$/kWh	0.05365	0.00000	[redacted]	[redacted]	[redacted]	0.27181	0.00000	[redacted]	[redacted]	[redacted]	108
109	Off-Peak Energy	$/kWh	0.04522	0.00000	[redacted]	[redacted]	[redacted]	0.22909	0.00000	[redacted]	[redacted]	[redacted]	109
110					[redacted]	[redacted]	[redacted]			[redacted]	[redacted]	[redacted]	110
111	*Primary*				[redacted]	[redacted]	[redacted]			[redacted]	[redacted]	[redacted]	111
112	**Summer**				[redacted]	[redacted]	[redacted]			[redacted]	[redacted]	[redacted]	112
113	On-Peak Demand	$/kW		2.64526	[redacted]	[redacted]	[redacted]		13.40106	[redacted]	[redacted]	[redacted]	113
114	On-Peak Energy	$/kWh	0.03863		[redacted]	[redacted]	[redacted]	0.19572		[redacted]	[redacted]	[redacted]	114
115	Semi-Peak Energy	$/kWh	0.04948	0.02816	[redacted]	[redacted]	[redacted]	0.25067	0.14266	[redacted]	[redacted]	[redacted]	115
116	Off-Peak Energy	$/kWh	0.04298	0.00208	[redacted]	[redacted]	[redacted]	0.21772	0.01056	[redacted]	[redacted]	[redacted]	116
117					[redacted]	[redacted]	[redacted]			[redacted]	[redacted]	[redacted]	117

ATTACHMENT A.2

SAN DIEGO GAS & ELECTRIC
2022 GENERAL RATE CASE (GRC) PHASE 2 - APPLICATION 23-01-XXX
ILLUSTRATIVE COMMODITY MARGINAL COSTS AND EPMC RATES AND REVENUES, LEGACY TOU - DE TURI (CH. 5)

PRIVILEGED AND CONFIDENTIAL PURSUANT TO P.U.C. CODE 583, 454.5(g), GO 66-C AND D.06-06-066 as needed

Line No.	Description (A)	Unit (B)	Marginal Energy Rate (C)	Marginal Capacity Rate (D)	Marginal Energy Rate Revenue (E)	Marginal Capacity Rate Revenue (F)	Total Marginal Rate Revenue (G)	EPMC Energy Rate (H)	EPMC Capacity Rate (I)	EPMC Energy Rate Revenue (J)	EPMC Capacity Rate Revenue (K)	Total EPMC Rate Revenue (L)	Line No.
118	**Winter**				[redacted]					[redacted]			118
119	On-Peak Demand	$/kW		0.00000					0.00000				119
120	On-Peak Energy	$/kWh	0.07523					0.38114					120
121	Semi-Peak Energy	$/kWh	0.05342	0.00000				0.27061	0.00000				121
122	Off-Peak Energy	$/kWh	0.04507	0.00000				0.22831	0.00000				122
123													123
124	**LIGHTING**												124
125	*Secondary*												125
126	**Summer**												126
127	On-Peak Demand	$/kW		0.10774					0.54581				127
128	On-Peak Energy	$/kWh	0.03884					0.19675					128
129	Semi-Peak Energy	$/kWh	0.04971	0.02333				0.25185	0.11819				129
130	Off-Peak Energy	$/kWh	0.04313	0.00147				0.21850	0.00746				130
131													131
132	**Winter**												132
133	On-Peak Demand	$/kW		0.00000					0.00000				133
134	On-Peak Energy	$/kWh	0.07560					0.38300					134
135	Semi-Peak Energy	$/kWh	0.05365	0.00000				0.27181	0.00000				135
136	Off-Peak Energy	$/kWh	0.04522	0.00000				0.22909	0.00000				136
137													137
138	**TOTAL RATE REVENUE SUMMARY**												138
139													139
140					Energy	Capacity	Total			Energy	Capacity	Total	140
141	**RESIDENTIAL**				[redacted]					[redacted]			141
142	**SMALL COMMERCIAL**												142
143	**MEDIUM COMMERCIAL**												143
144	**LARGE C&I**												144
145	**AGRICULTURAL**												145
146	**LIGHTING**												146
147	**TOTAL**												147

ATTACHMENT A.3

SAN DIEGO GAS & ELECTRIC
2022 GENERAL RATE CASE (GRC) PHASE 2 - APPLICATION 23-01-XXX
ILLUSTRATIVE COMMODITY MARGINAL COSTS AND EPMC RATES AND REVENUES, 2 PERIOD TOU - DE TURI (CH. 5)

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Line No.	Description (A)	Unit (B)	Marginal Energy Rate (C)	Marginal Capacity Rate (D)	Marginal Energy Rate Revenue (E)	Marginal Capacity Rate Revenue (F)	Total Marginal Rate Revenue (G)	EPMC Energy Rate (H)	EPMC Capacity Rate (I)	EPMC Energy Rate Revenue (J)	EPMC Capacity Rate Revenue (K)	Total EPMC Rate Revenue (L)	Line No.
1	**SMALL COMMERCIAL**												1
2	*Secondary*												2
3	**Summer**												3
4	On-Peak Demand	$/kW		3.49025	[redacted]				21.78839	[redacted]			4
5	On-Peak Energy	$/kWh	0.04864					0.30367					5
6	Off-Peak Energy	$/kWh	0.04276	0.00202				0.26694	0.01263				6
7													7
8	**Winter**												8
9	On-Peak Demand	$/kW		0.00000					0.00000				9
10	On-Peak Energy	$/kWh	0.06803					0.42471					10
11	Off-Peak Energy	$/kWh	0.04650	0.00000				0.29030	0.00000				11
12													12
13	*Primary*												13
14	**Summer**												14
15	On-Peak Demand	$/kW		3.47341					21.68331				15
16	On-Peak Energy	$/kWh	0.04841					0.30220					16
17	Off-Peak Energy	$/kWh	0.04259	0.00202				0.26585	0.01258				17
18													18
19	**Winter**												19
20	On-Peak Demand	$/kW		0.00000					0.00000				20
21	On-Peak Energy	$/kWh	0.06772					0.42277					21
22	Off-Peak Energy	$/kWh	0.04633	0.00000				0.28922	0.00000				22
23													23
24	**AGRICULTURE**												24
25	*Secondary*												25
26	**Summer**												26
27	On-Peak Demand	$/kW		5.61565					35.05659				27
28	On-Peak Energy	$/kWh	0.04864					0.30367					28
29	Off-Peak Energy	$/kWh	0.04276	0.00158				0.26694	0.00987				29
30													30
31	**Winter**												31
32	On-Peak Demand	$/kW		0.00000					0.00000				32
33	On-Peak Energy	$/kWh	0.06803					0.42471					33
34	Off-Peak Energy	$/kWh	0.04650	0.00000				0.29030	0.00000				34
35													35
36	*Primary*												36
37	**Summer**												37
38	On-Peak Demand	$/kW		5.58857					34.88751				38
39	On-Peak Energy	$/kWh	0.04841					0.30220					39

ATTACHMENT A.3

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2022 GENERAL RATE CASE (GRC) PHASE 2 - APPLICATION 23-01-XXX
ILLUSTRATIVE COMMODITY MARGINAL COSTS AND EPMC RATES AND REVENUES, 2 PERIOD TOU - DE TURI (CH. 5)

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40	Off-Peak Energy	$/kWh	0.04259	0.00157	[redacted]			0.26585	0.00983	[redacted]			40
41													41
42	**Winter**												42
43	On-Peak Demand	$/kW		0.00000					0.00000				43
44	On-Peak Energy	$/kWh	0.06772					0.42277					44
45	Off-Peak Energy	$/kWh	0.04633	0.00000				0.28922	0.00000				45
46													46
47	**<u>TOTAL RATE REVENUE SUMMARY</u>**												47
48													48
49					**Energy**	**Capacity**	**Total**			**Energy**	**Capacity**	**Total**	49
50	**RESIDENTIAL**				[redacted]					[redacted]			50
51	**SMALL COMMERCIAL**												51
52	**MEDIUM COMMERCIAL**												52
53	**LARGE C&I**												53
54	**AGRICULTURAL**												54
55	**LIGHTING**												55
56	**TOTAL**												56

ATTACHMENT B

Illustrative Commodity Revenue Allocations

ATTACHMENT B

SAN DIEGO GAS & ELECTRIC
2022 GENERAL RATE CASE (GRC) PHASE 2 - APPLICATION 23-01-XXX
ILLUSTRATIVE COMMODITY REVENUE ALLOCATIONS - DE TURI (CH. 5)

Commodity Marginal Cost Allocation by Customer Class
GRC P2 Proposed TOU

		MARGINAL ENERGY COSTS		MARGINAL CAPACITY COSTS		
Line No.	Customer Class (A)	% Allocation (B)	$ Allocation (C)	% Allocation (D)	$ Allocation (E)	Line No.
1	RESIDENTIAL	53.40%	$ 85,393,720	63.80%	$ 16,539,906	1
2	SMALL COMMERCIAL	10.47%	$ 16,752,046	10.37%	$ 2,689,319	2
3	MEDIUM COMMERCIAL	11.93%	$ 19,086,577	13.09%	$ 3,394,620	3
4	LARGE C&I	22.84%	$ 36,530,697	11.45%	$ 2,967,317	4
5	AGRICULTURAL	0.89%	$ 1,422,248	1.12%	$ 291,308	5
6	LIGHTING	0.46%	$ 739,446	0.16%	$ 42,043	6
7	TOTAL	100.00%	$ 159,924,734	100.00%	$ 25,924,513	7

Current TOU versus Proposed TOU

		CURRENT		PROPOSED				
Line No.	Customer Class (A)	% Allocation (B)	$ Allocation (C)	% Allocation (D)	$ Allocation (E)	$ Change (F)	% Change (G)	Line No.
8	RESIDENTIAL	49.91%	$ 541,478,900	54.85%	$ 595,090,035	$ 53,611,134	9.90%	8
9	SMALL COMMERCIAL	11.81%	$ 128,093,459	10.46%	$ 113,498,983	$ (14,594,477)	-11.39%	9
10	MEDIUM COMMERCIAL	0.00%	$ -	12.10%	$ 131,245,564	$ 131,245,564	N/A	10
11	LARGE C&I	35.38%	$ 383,880,161	21.25%	$ 230,589,995	$ (153,290,166)	-39.93%	11
12	AGRICULTURAL	2.38%	$ 25,826,079	0.92%	$ 10,003,764	$ (15,822,314)	-61.26%	12
13	LIGHTING	0.53%	$ 5,712,086	0.42%	$ 4,562,344	$ (1,149,741)	-20.13%	13
14	TOTAL	100.00%	$ 1,084,990,685	100.00%	$ 1,084,990,685	$ -	0.00%	14

ATTACHMENT C

Illustrative CTC Revenue Allocations

ATTACHMENT C

SAN DIEGO GAS & ELECTRIC
2022 GENERAL RATE CASE (GRC) PHASE 2 - APPLICATION 23-01-XXX
ILLUSTRATIVE CTC REVENUE ALLOCATIONS - DE TURI (CH. 5)

CTC Allocation by Customer Class

Line No.	Customer Class (A)	CURRENT % Allocation (B)	CURRENT $ Allocation (C)	PROPOSED % Allocation (D)	PROPOSED $ Allocation (E)	$ Change (F)	% Change (G)	Line No.
1	**Residential**	43.24%	$ 8,353,928	63.94%	$ 12,354,229	$ 4,000,301	47.89%	1
2	**Small Commercial**	11.93%	$ 2,304,295	11.87%	$ 2,293,912	$ (10,382)	-0.45%	2
3	**Medium Commercial**	0.00%	$ -	12.21%	$ 2,360,106	$ 2,360,106	N/A	3
4	**Large Commercial & Industrial**	43.54%	$ 8,413,237	10.39%	$ 2,007,101	$ (6,406,136)	-76.14%	4
5	**Agricultural**	1.10%	$ 212,831	1.50%	$ 289,022	$ 76,191	35.80%	5
6	**Lighting**	0.20%	$ 37,765	0.09%	$ 17,685	$ (20,081)	-53.17%	6
7	**Total**	100.00%	$ 19,322,055	100.00%	$ 19,322,055	$ -	0.00%	7

ATTACHMENT D

Illustrative Legacy TOU Marginal Energy Costs

ATTACHMENT D.1

SAN DIEGO GAS & ELECTRIC
2022 GENERAL RATE CASE (GRC) PHASE 2 - APPLICATION 23-01-XXX
ILLUSTRATIVE LEGACY TOU MARGINAL ENERGY COSTS - DE TURI (CH. 5)

Legacy TOU

SDG&E Legacy TOU Periods	A Wholesale (¢/kWh)	B RPS Premium (¢/kWh)	A+B Total (¢/kWh)
Summer (June 1 - October 31)			
On-Peak: 11 a.m. to 6 p.m. Weekdays	3.0473	0.6028	3.6501
Semi Peak: 6 a.m. to 11 a.m., 6 p.m. to 10 p.m. Weekdays	4.0861	0.6028	4.6889
Off Peak: 10 p.m. to 6 a.m. Weekdays; all hours Weekends/Holidays	3.4874	0.6028	4.0902
Winter (November 1 - May 31)			
On-Peak: 5 p.m. to 8 p.m. Weekdays	6.5226	0.6028	7.1254
Semi Peak: 6 a.m. to 5 p.m., 8 p.m. to 10 p.m. Weekdays	4.4672	0.6028	5.0700
Off-Peak: 10 p.m. to 6 a.m. Weekdays; all hours Weekends/Holidays	3.6894	0.6028	4.2922
	RPS Premium	$ 13.70	
	RPS %	44%	

ATTACHMENT D.2

SAN DIEGO GAS & ELECTRIC
2022 GENERAL RATE CASE (GRC) PHASE 2 - APPLICATION 23-01-XXX
ILLUSTRATIVE LEGACY TOU MARGINAL ENERGY COSTS - DE TURI (CH. 5)

Two-Period TOU

SDG&E Two-Period TOU Periods	A Wholesale (¢/kWh)	B RPS Premium (¢/kWh)	A+B Total (¢/kWh)
Summer (June 1 - October 31)			
On-Peak: 4 p.m. to 9 p.m. Everyday	3.9821	0.6028	4.5849
Off Peak: 12 a.m. to 4 p.m., 9 p.m. to 12 a.m. Everyday	3.4421	0.6028	4.0449
Winter (November 1 - May 31)			
On-Peak: 4 p.m. to 9 p.m. Everyday	5.8193	0.6028	6.4221
Off Peak: 12 a.m. to 4 p.m., 9 p.m. to 12 a.m. Everyday	3.8049	0.6028	4.4077
	RPS Premium	$ 13.70	
	RPS %	44%	

ATTACHMENT E

Declaration of Jeff DeTuri Regarding Confidentiality Of Certain Data/Documents Pursuant To D.06-06-066, *et al.*

BEFORE THE PUBLIC UTILITIES COMMISSION
OF THE STATE OF CALIFORNIA

DECLARATION
OF JEFF DE TURI

Application 23-01-008
2024 General Rate Case Phase 2

I, Jeff DeTuri, declare as follows:

1. I am a Real Time Pricing Manager for San Diego Gas & Electric Company ("SDG&E"). As the Real Time Pricing Manager, I am thoroughly familiar with the facts and representations in this declaration, and if called upon to testify I could and would testify to the following based upon personal knowledge.

2. I am providing this Declaration to demonstrate that the confidential information ("Protected Information") in support of the referenced application falls within the scope of data provided confidential treatment in the IOU Matrix ("Matrix") attached to the Commission's Decision ("D.") 06-06-066 (the Phase I Confidentiality decision), as modified by D.07-05-032, D.08-04-023, and D.20-07-005. In addition, the Commission has made clear that information must be protected where "it matches a Matrix category exactly… or consists of information from which that information may be easily derived."[1] Pursuant to the procedure adopted in D.08-04-023, I am addressing each of the following five features of Ordering Paragraph 2 of D.06-06-066:

- that the material constitutes a particular type of data listed in the Matrix;
- the category or categories in the Matrix the data correspond to;
- that SDG&E is complying with the limitations on confidentiality specified in the Matrix for that type of data;

[1] *See Administrative Law Judge's Ruling on San Diego Gas & Electric Company's April 3, 2007 Motion to File Data Under Seal,* issued May 4, 2007 in R.06-05-027, p. 2.

- that the information is not already public; and
- that the data cannot be aggregated, redacted, summarized, masked or otherwise protected in a way that allows partial disclosure.

3. The Protected Information contained in the Prepared Direct Testimony of Jeff DeTuri Chapter 5 Marginal Commodity Cost Attachment A to Application 23-01-008 constitutes material, market sensitive, electric procurement-related information that is within the scope of Section 454.5(g) of the Public Utilities Code.[2] As such, the Protected Information is allowed confidential treatment in accordance with the Matrix, as follows:

Confidential Information	**Matrix Reference**	**Reason for Confidentiality and Timing**
Cells highlighted in yellow in the Attachment A.1, A.2, and A.3	V.C	LSE Total Energy Forecast – Bundled Customer, confidential for the front three years

4. I am not aware of any instances where the Protected Information is available to the public. To my knowledge, no party, including SDG&E, has publicly revealed any of the Protected Information, with the exception of an inadvertent disclosure as part of this proceeding. The information is no longer publicly available and all parties notified of its initial availability have been instructed to destroy the inadvertently disclosed information.

5. SDG&E will comply with the limitations on confidentiality specified in the Matrix for the Protected Information.

6. The Protected Information cannot be provided in a form that is aggregated, partially redacted, or summarized, masked or otherwise protected in a manner that would allow further disclosure of the data while still protecting confidential information.

[2] In addition to the details addressed herein, SDG&E believes that the information being furnished in my Testimony is governed by Public Utilities Code Section 583 and General Order 66-D. Accordingly, SDG&E seeks confidential treatment of this data under those provisions, as applicable.

I declare under penalty of perjury under the laws of the State of California that the foregoing is true and correct.

Executed this 2nd day of February, 2023, at San Diego, California.

*/s/ Jeff DeTuri*____________
Jeff DeTuri
Real Time Pricing Manager
San Diego Gas & Electric Company