

Application No.: A.18-04-  
Exhibit No.: \_\_\_\_\_  
Witness: Jennifer Montanez

**PREPARED DIRECT TESTIMONY OF**  
**JENNIFER MONTANEZ**  
**ON BEHALF OF**  
**SAN DIEGO GAS & ELECTRIC COMPANY**

***\*\*redacted, public version\*\****

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

April 13, 2018



**TABLE OF CONTENTS**

- I. INTRODUCTION ..... 1
- II. 2019 FORECAST OF ENERGY REQUIREMENTS AND SUPPLY RESOURCES ..... 3
  - A. ENERGY REQUIREMENTS FORECAST ..... 3
  - B. SUPPLY RESOURCE FORECAST ..... 3
    - 1. SDG&E-Contracted Generation ..... 3
    - 2. SDG&E-Owned Dispatchable Generation ..... 5
    - 3. Renewable Energy Contracts ..... 6
    - 4. Qualifying Facilities Contracts ..... 8
    - 5. Market Purchases and Surplus Sales ..... 8
- III. 2019 FORECAST OF ERRA EXPENSES ..... 9
  - A. ISO LOAD CHARGES ..... 9
  - B. ISO SUPPLY REVENUES ..... 10
  - C. CONTRACTED ENERGY PURCHASES ..... 10
    - 1. Purchased Power Contracts ..... 10
    - 2. Renewable Energy Contracts ..... 10
    - 3. Qualifying Facilities Contracts ..... 11
  - D. GENERATION FUEL ..... 12
    - 1. Palomar, Desert Star, Miramar and Cuyamaca (Fuel Expenses that are Recovered through ERRA) ..... 12
  - E. LOCAL GENERATION ..... 12
  - F. CAISO RELATED COSTS ..... 13
  - G. HEDGING COSTS & FINANCIAL TRANSACTIONS ..... 13
  - H. CONVERGENCE BIDS ..... 14
  - I. CONGESTION REVENUE RIGHTS (“CRRs”) ..... 14
  - J. INTER-SCHEDULING COORDINATOR TRADES (“IST”) ..... 15

IV.	SONGS UNIT 1 OFFSITE SPENT FUEL STORAGE COSTS .....	16
	A. Background.....	16
	B. 2019 Forecast.....	16
V.	2019 FORECAST OF GHG COSTS.....	17
	A. Direct GHG Emissions .....	18
	B. Indirect GHG Emissions.....	20
	C. 2019 GHG Costs.....	22
	D. 2019 Allowance Auction Revenues.....	22
VI.	CONCLUSION.....	23
VII.	QUALIFICATIONS .....	23
	ATTACHMENT A (CONFIDENTIAL)	
	ATTACHMENT B (CONFIDENTIAL)	
	ATTACHMENT C	
	ATTACHMENT D (CONFIDENTIAL)	
	ATTACHMENT E (CONFIDENTIAL)	
	GLOSSARY	

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**PREPARED DIRECT TESTIMONY OF  
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5 **I. INTRODUCTION**

6 My testimony describes the resources San Diego Gas & Electric Company (“SDG&E”)  
7 expects to use in calendar year 2019 to provide electric commodity service to its bundled service  
8 customers; provides a forecast of the procurement costs that SDG&E expects to record in 2019  
9 to the Energy Resource Recovery Account (“ERRA”), Transition Cost Balancing Account  
10 (“TCBA”), and Local Generation Balancing Account (“LGBA”); provides a 2019 forecast of  
11 SDG&E’s San Onofre Generating Station (“SONGS”) Unit 1 Offsite Spent Fuel Storage Costs;  
12 and provides a forecast of 2019 total greenhouse gas (“GHG”) costs. SDG&E witness Mrs. Ngo  
13 uses my forecast of ERRA, Competition Transition Charge (“CTC”) and Local Generation  
14 (“LG”) in developing 2019 revenue requirements for each element. In addition, my testimony  
15 provides information that supports SDG&E witness Ms. McKay’s development of the GHG  
16 allowance revenue return allocation and the volumetric revenue return for small business and  
17 residential customers, as well as rates for the Green Tariff Shared Renewables (“GTSR”)  
18 program and the Power Charge Indifference Adjustment (“PCIA”).

19 In Section II of my testimony, I provide a forecast of the energy requirements that will be  
20 required to serve SDG&E’s bundled customer load for 2019, as well as forecasts of the supply  
21 resources that SDG&E expects to utilize to meet that load in calendar year 2019. The supply  
22 resources for which I provide forecasts include (1) generation resources that are under contract  
23 for 2019; (2) generation resources owned by SDG&E; (3) renewable generation resources that

1 are under contract for 2019; (4) Qualifying Facilities (“QFs”) under the Public Utility Regulatory  
2 Policies Act (“PURPA”) that are under contract for 2019; and (5) generation obtained through  
3 market purchases.

4 In Section III of my testimony, I quantify the costs associated with the resources  
5 described in Section II, along with other electric procurement costs that are recorded in ERRRA,  
6 such as market purchases, California Independent System Operator (“CAISO”) charges and  
7 portfolio hedging costs. These costs are summarized in Attachment A.

8 In Section IV of my testimony, I provide a forecast of the 2019 SONGS Unit 1 Offsite  
9 Spent Fuel Storage Costs associated with SDG&E’s 20% minority ownership interest in  
10 SONGS.

11 In Section V of my testimony, I provide a forecast of the 2019 GHG emissions and  
12 associated costs, both direct and indirect, incurred in connection with SDG&E’s compliance with  
13 California’s cap-and-trade program. I also provide a forecast of GHG allowance auction  
14 revenues. Lastly, I provide a statement of qualifications.

15 My testimony refers to the following attachments:

16 Attachment A: SDG&E 2019 ERRRA and LG Expenses

17 Attachment B: SDG&E 2019 Generation Portfolio Delivery Volumes

18 Attachment C: SDG&E 2019 Renewable Resource Detail

19 Attachment D: SDG&E 2019 CTC & QF Detail

20 Attachment E: SDG&E GHG Detail.  
21

1 **II. 2019 FORECAST OF ENERGY REQUIREMENTS AND SUPPLY RESOURCES**

2 **A. ENERGY REQUIREMENTS FORECAST**

3 As a starting point for my analysis, I developed a forecast of SDG&E’s 2019 bundled  
4 load requirement, which is based on the California Energy Commission’s (“CEC”) 2017 IEPR  
5 Demand Forecast for SDG&E, adopted in February 2018. Using this forecast and adjusting for  
6 direct access load, I project that the energy requirements for its bundled load for 2019 will be  
7 [REDACTED]. The 2019 forecast is [REDACTED] or [REDACTED] less than SDG&E’s  
8 forecasted bundled energy forecast for 2018 [REDACTED].

9 **B. SUPPLY RESOURCE FORECAST**

10 After determining the amount of energy that SDG&E’s bundled load customers will  
11 require in 2019, I then proceeded to develop a forecast of the supply resources that will be  
12 needed to meet that demand. To quantify the generation associated with the supply resources, I  
13 used the same production cost model SDG&E has used in past ERRRA forecasts. Inputs to this  
14 model include the characteristics of the various generation resources, including heat rate,  
15 variable Operating and Maintenance (“O&M”) costs, and other factors that impact the plant’s  
16 dispatch, and natural gas and market prices. The natural gas and electric market price forecasts  
17 were derived using a recent (March 1, 2018) assessment of 2019 market prices, based on the  
18 average of forward prices over the previous 22 market trading days. I then run the model which  
19 simulates a least-cost dispatch of the portfolio of SDG&E’s resources for every hour of 2019.  
20 The supply resources fall into the following five categories.

21 **1. SDG&E-Contracted Generation**

22 SDG&E has a number of generation resources under contract in its 2019 resource  
23 portfolio. These resources are available under a variety of contractual arrangements, including

1 tolling contracts, fixed energy contracts, and contracts for Resource Adequacy only. The largest  
2 of the tolling and fixed energy contracts are:

- 3 • the Otay Mesa Energy Center (“OMECE”) Power Purchase Agreement (“PPA”) for  
4 the output of a 599 megawatt (“MW”) combined-cycle power plant<sup>1</sup>;
- 5 • the Carlsbad Energy Center PPA for the output of a 500 MW simple cycle  
6 combustion turbine unit;
- 7 • the Pio Pico Energy Center PPA for the output of a 308 MW simple cycle  
8 combustion turbine unit;
- 9 • the Orange Grove PPA for the output of two 48 MW simple cycle combustion  
10 turbine units;
- 11 • the El Cajon Energy Center PPA for the output of a 47 MW simple cycle  
12 combustion turbine unit;
- 13 • the Escondido Energy Center PPA for the output of a 48 MW simple cycle  
14 combustion turbine unit;
- 15 • the BP PPA, which provides firm energy deliveries at the SDG&E Default Load  
16 Aggregation Point (“DLAP”); and
- 17 • the Morgan Stanley PPA, which provides firm energy deliveries at the Northern  
18 Oregon Border (“NOB”).

19 The forecasted generation for these contracts is detailed in Attachment B and is  
20 summarized in Table 1 below:

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<sup>1</sup> Otay Mesa Energy Center PPA contract ends October 3, 2019. For purposes of this filing, we assume this resource will be “put” on SDG&E; therefore, making it Utility Owned Generation starting October 3, 2019.

1

		<b>Table 1: Generation (GWh)</b>		
		<b>2019</b>	<b>2018</b>	<b>Difference</b>
<b>OMECE</b>				
<b>Carlbad Energy Center</b>				
<b>Pio Pico Energy Center</b>				
<b>Orange Grove</b>				
<b>El Cajon Energy Center</b>				
<b>Escondido Energy Center</b>				
<b>BP</b>				
<b>Morgan Stanley NOB</b>				
	<b>Total</b>			

2

3 SDG&E also enters into contracts each year to meet its CPUC Resource Adequacy  
4 requirements.<sup>2</sup> Under its Resource Adequacy contracts, SDG&E is entitled to show this capacity  
5 as meeting its Resource Adequacy obligation, but SDG&E does not have rights to the energy or  
6 ancillary services from these units. For 2019, SDG&E forecasts that it will enter into contracts  
7 for up to [REDACTED] of Resource Adequacy capacity.

8 **2. SDG&E-Owned Dispatchable Generation**

9 SDG&E owns several generation facilities, which it uses to meet its bundled customer  
10 load, including the following:

- 11 • the Palomar Energy Center (“Palomar”), a 575 MW combined cycle power plant;
- 12 • the Desert Star Energy Center (“Desert Star”), a 485 MW combined cycle power  
13 plant;
- 14 • the Miramar Energy Facility (“Miramar I and II”), consisting of two 48 MW  
15 simple cycle combustion turbine units;

<sup>2</sup> California Public Utilities Code Section 380 established the Resource Adequacy program to provide sufficient resources to the CAISO to ensure the safe and reliable operation of the grid in real time and to provide appropriate incentives for the siting and construction of new resources needed for reliability in the future.



- the Battery Storage facilities, consisting of Escondido at 30 MW, El Cajon at 7.5 MW, and Miramar at 30 MW; and
- the Cuyamaca Peak Energy Plant, consisting of a 47 MW simple cycle combustion turbine.

These units are dispatched by the CAISO for generation and ancillary services (“A/S”) awards based on economic merit.<sup>3</sup> The forecasted generation for these plants is detailed in Attachment B and is summarized in Table 2 below:

		<b>Table 2: Generation (GWh)</b>		
		<b>2019</b>	<b>2018</b>	<b>Difference</b>
<b>Palomar</b>				
<b>Desert Star</b>				
<b>Miramar</b>				
<b>Battery Storage</b>				
<b>Cuyamaca</b>				
	<b>Total</b>			

### 3. Renewable Energy Contracts

The 2019 forecast of renewable energy supply from CPUC-approved contracts is 6,920 GWh, which includes 1,236 GWh of Renewable Energy Credit (“REC”) quantities<sup>4</sup> that are delivered to SDG&E in conjunction with existing non-renewable imports. This forecast represents a decrease of 309 GWh from the 2018 forecast (7,229 GWh) and represents [REDACTED] of forecasted bundled sales. The forecasted generation associated with SDG&E’s monthly renewable contracts is set forth in Attachment C.

<sup>3</sup> SDG&E’s dispatch model considered only generation dispatched for energy and not for A/S because the CAISO co-optimizes market awards between energy and A/S based on the opportunity cost of capacity. Thus, the economic benefit (and ERRRA contribution) of using capacity for generation is equivalent to using capacity for A/S.

<sup>4</sup> Renewable Energy Credits represent the green attribute of renewable generation and, while they can be purchased independent of physical delivery of generation from the source, they must accompany a delivery of “tagged” physical power to be imported into California.

1 For 2019, SDG&E forecasts it will receive 5,684 GWh of bundled renewable energy  
 2 under 48 contracts with facilities that generate electricity using wind, solar, biogas, and pumped  
 3 hydro technologies. The forecasted generation for projects that are currently on-line and  
 4 operating is derived from generation profiles based on historical data. The forecasted generation  
 5 for those projects that have recently come online and that are expected to continue operations in  
 6 2019<sup>5</sup> is based on historical data of resources that utilize similar renewable technologies.

7 In addition, SDG&E expects to receive 1,236 GWh of firmed-and-shaped power from  
 8 three out-of-state wind projects, Rim Rock and Naturener Glacier 1 and 2 (Montana).<sup>6</sup> The  
 9 RECs are delivered to California independently of the physical delivery of generation by the  
 10 source wind projects. This is done by tagging equivalent quantities of the physical deliveries of  
 11 other energy imports that SDG&E has already accounted for in its 2019 forecast. The forecasted  
 12 energy mix from these renewable resources is shown in Table 3 below:

<b>Table 3: Generation (GWh)</b>			
	<b>2019</b>	<b>2018</b>	<b>Difference</b>
<b>Solar</b>	3,625	3,620	5
<b>Wind</b>	1,874	2,206	(332)
<b>Wind RECs</b>	1,236	1,236	-
<b>Biogas</b>	182	165	17
<b>Other</b>	2	2	0
<b>RPS Sales</b>	-	-	-
<b>Total</b>	<b>6,920</b>	<b>7,229</b>	<b>(309)</b>

<sup>5</sup> SDG&E did not include renewable energy quantities or costs associated with the Sustainable Communities Photovoltaic program because costs for this program are not charged to ERRRA.

<sup>6</sup> The firmed-and-shaped wind power from these contracts is delivered to California through the Morgan Stanley power contract described above.

1                   **4.     Qualifying Facilities Contracts**

2                   In 2019, SDG&E will have approximately 110 MW of capacity under contract with three  
3 QFs.<sup>7</sup> The two largest QF contracts account for 106.5 MW or 98% of total QF capacity. All of  
4 these QFs are located in SDG&E’s service area except for the Yuma Cogeneration Associates  
5 (“YCA”) plant, a 56.5 MW natural gas-fired plant located in Arizona, the output of which is  
6 imported into the CAISO.

7                   SDG&E’s QF contracts include a combination of must-take and dispatchable resources.  
8 For must-take resources, SDG&E is obligated to pay the contract price for all delivered QF  
9 generation and schedule it into the CAISO market; SDG&E has no such obligation with  
10 dispatchable resources. SDG&E has amendments with Goal Line and YCA, which provide  
11 SDG&E with more economic dispatch rights. SDG&E forecasted the plants’ dispatch in  
12 accordance with these terms. The forecast of QF energy supply in 2019 is [REDACTED]. The  
13 forecasted generation for these plants is detailed in Attachment D.

14                   **5.     Market Purchases and Surplus Sales**

15                   Under the Market Redesign and Technology Upgrade (“MRTU”),<sup>8</sup> there is no  
16 requirement that SDG&E balance its bundled load and its controlled generation quantities that  
17 clear the market. If, in any hour, the quantity of SDG&E’s bundled load requirements purchased  
18 from the CAISO is greater than SDG&E-controlled generation dispatched by the CAISO, the  
19 difference may be viewed as equivalent to a market purchase.<sup>9</sup> Similarly, if more SDG&E

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<sup>7</sup> The actual number of active QF contracts is over 50, but many of these QF resources only serve on-site load and do not deliver net energy to SDG&E. As a result, these are not included in the production cost model analysis. The three QFs referenced above deliver net energy to SDG&E and are thus included in SDG&E’s model.

<sup>8</sup> In 2009, the CAISO implemented the Market Redesign and Technology Upgrade which primarily transformed the CAISO market from a zonal to a nodal priced market.

<sup>9</sup> In some hours the quantity of SDG&E’s bundled load requirements purchased from the CAISO is less than SDG&E-controlled generation sold to the CAISO. The difference may be viewed as equivalent

1 generation is dispatched than SDG&E load requirements it is assumed to offset market purchases  
2 in other time periods. SDG&E forecasts that the quantity of equivalent market purchases will be  
3 [REDACTED] in 2019, an increase of [REDACTED] from the 2018 forecast [REDACTED].

### 4 **III. 2019 FORECAST OF ERRA EXPENSES**

5 To quantify the costs associated with the supply resources described in Section II, the  
6 production cost model also tracks the costs of the economic dispatch. Electric procurement  
7 expenses incurred by SDG&E to serve its bundled load are also recorded to the ERRA. These  
8 expenses include, among other items, costs and revenues for energy and capacity cleared through  
9 the CAISO market, power purchase contract costs, generation fuel costs, market energy purchase  
10 costs, CAISO charges, brokerage fees, and hedging costs.

11 I expect that SDG&E will incur \$1.114 billion of ERRA costs in 2019,<sup>10</sup> as reflected in  
12 Attachment A. This forecast is \$227 million less than the \$1.341 billion forecasted for 2018.

13 In the remainder of this Section, I will discuss in greater detail the cost forecasts for  
14 specific ERRA items.

#### 15 **A. ISO LOAD CHARGES**

16 The CAISO supplies and sells to SDG&E the energy and A/S necessary to meet  
17 SDG&E's bundled load requirement. Based on forecasted prices for energy and A/S, SDG&E's  
18 production cost model forecasts [REDACTED] of ISO load charges for 2019. This cost includes  
19 the indirect GHG costs embedded in the market price of energy. I present GHG quantities and  
20 costs in Section V.

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to a market sale and the costs and revenues for such transactions are accounted for in the forecast by the total fuel expenses and total ISO Supply revenues.

<sup>10</sup> This amount does not include Franchise Fees and Uncollectibles ("FF&U"), nor do any of the other figures in my testimony.

1           **B.     ISO SUPPLY REVENUES**

2           In the CAISO market, all generation from SDG&E’s resource portfolio is sold to the  
3 CAISO. Based on forecasted prices for energy, SDG&E’s production cost model forecasts  
4 revenues totaling [REDACTED] for generation sold in 2019.

5           **C.     CONTRACTED ENERGY PURCHASES**

6                   **1.     Purchased Power Contracts**

7           SDG&E’s forecast of total costs for non-renewable power purchase contracts in 2019 is  
8 [REDACTED]. These costs cover capacity payments and variable generation costs for OMEC,  
9 Orange Grove, Wellhead El Cajon and other facilities with which SDG&E has smaller contracts.  
10 The largest components in this category are capacity and generation costs for the OMEC unit,  
11 expected to be [REDACTED], and Resource Adequacy capacity costs, expected to be [REDACTED].  
12 The Morgan Stanley contract is also included in this category and is expected to cost [REDACTED]  
13 [REDACTED].

14                   **2.     Renewable Energy Contracts**

15           SDG&E’s renewable energy contracts usually contain only an energy payment and no  
16 capacity payment. In 2019, SDG&E’s renewable energy portfolio will include a cost for all the  
17 renewable power delivered based on contract prices and the renewable energy credits described  
18 in Section II under “Renewable Energy Contracts.” All costs associated with these contracts are  
19 booked as ERRA expenses and are forecasted to be \$664 million for 2019. Attachment C details  
20 the renewable projects by fuel type, their costs and forecasted energy deliveries.

21           Customers who opt into the Green Tariff Shared Renewables (“GTSR”) program, which  
22 consists of both a Green Tariff (“GT”) component and an Enhanced Community Renewables

1 (“ECR”) component, pay a subset of the renewable costs.<sup>11</sup> The estimated GT customer usage in  
2 2019 is 112.74 GWh.<sup>12</sup> The estimated GT charges include the cost of local solar<sup>13</sup> of  
3 \$58.05/megawatt hour (“MWh”), Grid Management Charges (“GMC”) of \$0.00070/kwh and  
4 Western Renewable Energy Generation Information System (“WREGIS”) costs of  
5 \$0.00001/kwh. The estimated total cost of GT in 2019 is \$6.5 million. The estimated ECR  
6 customer usage in 2019 is 0 GWh as this component is dependent on resources which are not  
7 expected to come on line until 2020. Therefore, no costs are expected in 2019 for ECR.  
8 Additionally, the solar value adjustment was calculated as \$0.00772/kwh. This is an increase  
9 from 2017 due to the change in methodology the CAISO uses to calculate the net qualifying  
10 capacity, resulting in a lower value for solar.<sup>14</sup>

### 11 **3. Qualifying Facilities Contracts**

12 SDG&E’s QF contracts consist of dispatchable capacity or firm capacity PURPA  
13 contracts. These contracts include provisions for both energy and capacity payments. The  
14 energy payments for QFs that are under firm capacity PURPA contracts are forecasted using  
15 SDG&E’s Short-Run Avoided Cost (“SRAC”) formula.<sup>15</sup> For the dispatchable contracts,  
16 SDG&E pays fuel, variable O&M and capacity payments. Most of these contracts, whether

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<sup>11</sup> Decision 15-01-051 authorizing the GTSR program was approved on January 29, 2015. The GT and ECR components are two separate rate offerings under the GTSR Program accessing different pools of solar resources and with different terms.

<sup>12</sup> GT and ECR usage forecasts were developed using average consumption estimates for each customer class in conjunction with program enrollment targets.

<sup>13</sup> To meet immediate GT customer demand, SDG&E will draw on existing Renewables Portfolio Standard (“RPS”) resources that are eligible to serve the GT component of the GTSR Program. The Interim GT Pool is a short-term approach and cost is based on the weighted average cost of contracts for included resources. Simultaneously, SDG&E will engage in procurement for projects built specifically to serve the GT component (GT Dedicated Procurement Projects). When GT Dedicated Procurement Projects are brought online, the Interim GT Pool will be phased out as allowed by program participation.

<sup>14</sup> Final Net Qualifying Capacity Report for Compliance Year 2018,

<http://www.caiso.com/planning/Pages/ReliabilityRequirements>.

<sup>15</sup> The derivation of the SRAC price for QF contracts is posted monthly on an SDG&E website:

<http://www2.sdge.com/SRAC/>.

1 PURPA or dispatchable, are considered CTC QF contracts,<sup>16</sup> and the ERRA expenses are based  
2 on delivered energy multiplied by the market price benchmark (“MPB”). Any costs, including  
3 capacity payments, greater than the market price benchmark are booked to the TCBA. For the  
4 purposes of ERRA accounting, ERRA expenses for CTC QF contracts are recorded on Line 5 of  
5 Attachment A, “Contract Costs (CTC up to market),” and are forecasted to be [REDACTED] in  
6 2019. Attachment D details the breakdown of all the units discussed in this section and shows  
7 the associated costs, both ERRA and TCBA, and the forecasted energy deliveries. These costs  
8 include the indirect GHG cost embedded in the market price that flows through the SDG&E  
9 SRAC formula. I present GHG quantities and costs in Section IV of my testimony.

10 **D. GENERATION FUEL**

11 **1. Palomar, Desert Star, Miramar and Cuyamaca (Fuel Expenses that**  
12 **are Recovered through ERRA)**

13 In 2019, the ERRA expense for generation fuel purchased by SDG&E for Palomar,  
14 Miramar I & II, Desert Star, Otay Mesa and Cuyamaca is forecasted to be [REDACTED].<sup>17</sup> These  
15 forecasted expenses include in lieu gas fees for Palomar which are also recovered in ERRA.  
16 These costs are calculated based on SDG&E’s forecasted fuel usage for this plant and the  
17 applicable tariffs, Schedule GP-SUR<sup>18</sup> and Schedule EG.<sup>19</sup>

18 **E. LOCAL GENERATION<sup>20</sup>**

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<sup>16</sup> The CP Kelco contract, however, is not considered a CTC contract. Thus, unlike other QF contracts, 100% of CP Kelco contract costs are included in ERRA.

<sup>17</sup> Capital and non-fuel operating costs for these plants are recovered in the Non-Fuel Generation Balancing Account (“NGBA”) as required by D.05-08-005, Resolution E-3896 and D.07-11-046.

<sup>18</sup> Customer-procured Gas Franchise Fee Surcharge.

<sup>19</sup> Natural Gas Intrastate Transportation Service for Electric Generation Customers.

<sup>20</sup> Pursuant to D.17-07-005, SDG&E updated its authorized rate of return on ratebase in Advice Letter (“AL”) 3120-E with impacts to revenue requirements reflected in the January 1, 2018 consolidated filing, which impacted the LG revenue requirement that was approved in D.17-12-014. This adjustment for SDG&E’s 2018 LG revenue requirement changes from \$160.427 million to \$160.218 million including FF&U.

1 As previously noted, SDG&E has entered into contracts for generation resources which  
2 specifically provide local Resource Adequacy for the SDG&E system. Because these contract  
3 costs are allocated to both bundled and direct access customers, the costs are accounted for in a  
4 separate Local Generating Balancing Account. The Escondido Energy Center, Kelco,  
5 Grossmont, Naval Station, North Island, Pio Pico, Carlsbad Energy Center, El Cajon Energy  
6 Storage, Hybrid Holdings Energy Storage, Miramar Energy Storage and Escondido Energy  
7 Storage contracts are included in this balancing account and are expected to cost [REDACTED],  
8 including direct and indirect GHG costs and net of supply ISO revenue. Attachment A details  
9 the breakdown of local generation expenses.

#### 10 F. CAISO RELATED COSTS

11 SDG&E forecasts the miscellaneous CAISO costs to be [REDACTED] in 2019. SDG&E  
12 also forecasts the cost of the FERC Fees and Western Renewable Energy Generation Information  
13 System to be [REDACTED] in 2019.

#### 14 G. HEDGING COSTS & FINANCIAL TRANSACTIONS

15 SDG&E's resource portfolio has substantial exposure to gas price volatility as a result of  
16 fuel requirements for its gas-fired resources, as well as the gas price-based pricing formula for its  
17 QF contracts. To manage this exposure, SDG&E engages in hedging activity, consistent with its  
18 CPUC approved procurement plan,<sup>21</sup> and it will book the resulting hedging costs and any  
19 realized gains and losses from hedge transactions to ERRA consistent with its CPUC-approved  
20 hedge plan. The estimate of hedging costs for 2019 is [REDACTED], calculated as the marked-to-  
21 market profit/loss of hedges already in place, plus expected broker fees. The profit/loss of these  
22 and future hedges placed will rise and fall with market prices. Therefore, the final cost or  
23 savings will not be known until the settlement process has been completed for the hedge

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<sup>21</sup> SDG&E's 2012 Long Term Procurement Plan, Appendix B: Electric and Gas Hedging Strategy.



1 transactions.

2           SDG&E may also trade short-term financial power products to hedge its long or short  
3 position against potentially volatile CAISO market clearing prices. SDG&E does not include a  
4 forecast of net cost or benefit from these power hedges due to the unpredictability of market  
5 prices relative to the price of the hedges.

#### 6           **H. CONVERGENCE BIDS**

7           SDG&E uses convergence bids<sup>22</sup> to hedge certain operational risks in the day-to-day  
8 management of its portfolio. It is not possible to forecast the gains or losses associated with  
9 potential convergence bidding activity because of the unpredictable relationship between day-  
10 ahead and real-time prices. Therefore, SDG&E did not forecast an ERRA revenue/charge for  
11 convergence bids.

#### 12           **I. CONGESTION REVENUE RIGHTS (“CRRs”)**

13           Market participants, including SDG&E, were allocated CRRs by the CAISO for which  
14 they can nominate source and sink P-nodes<sup>23</sup> to match those in their portfolio. If congestion  
15 arises between the source and sink P-nodes, the CAISO will pay the market participant holding  
16 the CRR the congestion charges to offset the congestion costs incurred. SDG&E expects its  
17 CRRs to generate revenues from the CAISO to offset congestion costs incurred within its  
18 portfolio. However, expected revenues were not forecast for the 2019 ERRA forecast because

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<sup>22</sup> A convergence bid (also known as a virtual bid) is not backed by any physical generation or load, and is thus completely financial. Convergence bidding allows market participants to arbitrage expected price differences between the Day-Ahead and Real-Time markets. Using convergence bids, market participants can sell (buy) energy in the Day-Ahead market, with the explicit requirement to buy (sell) that energy back in the Real-Time market, without intending to physically consume or produce energy in Real-Time. Convergence bids that clear the Day-Ahead market will either earn, or lose, the difference between the Day-Ahead and Real-Time market prices at a specified node multiplied by the megawatt volume of their bids.

<sup>23</sup> The source and the sink are the two ends of a path for which congestion may occur. The CRR represents the difference in the Marginal Cost of Congestion component of the Locational Marginal Prices for the Nodal Prices of the source and sink.

1 SDG&E assumed congestion-free clearing prices to develop forecasts for load requirement costs  
2 and generation revenues. A forecast of CRR revenues would have required SDG&E to forecast  
3 offsetting market-congestion prices at various P-nodes over the 2019 period. Since there are no  
4 forward market prices for congestion, we do not have a strong basis to perform this forecast  
5 without introducing complexity and additional uncertainty into the forecast.

6 Market participants, including SDG&E, are offered the ability to purchase CRRs through  
7 an auction process. SDG&E may elect to participate in the annual and monthly auction  
8 processes to procure the incremental CRRs. Since the incremental CRRs volumes cannot be  
9 forecasted, the incremental CRR costs and revenues also cannot be forecasted.

10 **J. INTER-SCHEDULING COORDINATOR TRADES (“IST”)**

11 In the CAISO market, SDG&E may transact ISTs<sup>24</sup> bilaterally with counterparties to  
12 hedge long or short positions. Under an IST purchase, SDG&E pays the counterparty the  
13 contracted energy price and in return receives payment from the CAISO based on the market  
14 clearing price. Under an IST sale, SDG&E receives payment from the counterparty based on the  
15 contracted energy price and in return pays the market clearing price to the CAISO. For IST  
16 purchases and sales, the payment to, or revenue from, the counterparty is largely offset by the  
17 respective credit from, or payment to, the CAISO. Because ISTs are used as a hedge against  
18 unknown market prices, SDG&E does not include a forecast of the net cost or benefit from these  
19 transactions.

20  
21  

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<sup>24</sup> ISTs are financial bilateral transactions which allow SDG&E to hedge long or short price positions in the market.

1     **IV. SONGS UNIT 1 OFFSITE SPENT FUEL STORAGE COSTS**

2             **A. Background**

3             SONGS Unit 1 ceased operation on November 30, 1992. Defueling was completed on  
4 March 6, 1993. On July 18, 2005, SDG&E submitted Advice Letter 1709-E, which removed  
5 SONGS Unit 1 shutdown O&M expense from the revenue requirement pursuant to D.04-07-022.  
6 Southern California Edison Company (“SCE”) – the majority owner of SONGS, has  
7 decommissioned the Unit 1 facility, and as of 2010, most of the Unit 1 structures and equipment  
8 have been removed and disposed of, except for areas shared by Units 2 and 3 for which physical  
9 decommissioning and dismantlement has only recently begun.

10            Spent fuel assemblies from SONGS Unit 1 have been stored since 1972 at the General  
11 Electric-Hitachi spent fuel storage facility located in Morris, Illinois. There are 270 spent fuel  
12 assemblies from SONGS Unit 1 currently in storage at that facility. Because there are no other  
13 facilities currently available in the U.S. for the commercial storage of spent nuclear fuel, those  
14 270 assemblies are expected to remain at the Morris facility until they are accepted for ultimate  
15 disposal by the U.S. Department of Energy. Pursuant to the terms of the storage contract with  
16 General Electric-Hitachi, payments are made monthly by SCE, which in turn bills SDG&E for its  
17 20% ownership share.

18            **B. 2019 Forecast**

19            SDG&E estimates its 2019 SONGS Unit 1 offsite spent fuel storage expense to be \$1.055  
20 million (\$1.068 million including FF&U), including adjustments for escalation, in accordance  
21 with the GE-Hitachi spent fuel storage contract.<sup>25</sup> The storage contract utilizes the Bureau of  
22 Labor Standards’ labor non-financial corporations and industrial commodities indices to forecast  
23 escalation rates, which are included in SCE’s billing statement to SDG&E. This estimate is

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<sup>25</sup> SDG&E may recover these costs through ERRRA per D.15-12-032.

1 based on a spent fuel storage cost forecast prepared by SCE’s Nuclear Fuel Manager utilizing the  
2 contract escalation terms.

### 3 **V. 2019 FORECAST OF GHG COSTS**

4 In this section, I describe the cost forecast for GHG compliance obligations under the  
5 California Air Resources Board (“ARB”) cap-and-trade program. The cap-and-trade program  
6 provides that compliance obligations in the electricity sector are applicable to “first deliverers of  
7 electricity.”<sup>26</sup> Generally, first deliverers of electricity in 2019 are electricity generators inside  
8 California that emit more than 25,000 metric tons (“MT”) of GHG, and importers of electricity  
9 from outside of California. The cap-and-trade program requires that first deliverers of  
10 electricity, except publicly-owned utilities and small generators (less than 25,000 MT of  
11 emissions), purchase all of the allowances and offsets needed to meet their compliance  
12 obligations.<sup>27</sup> SDG&E is the first deliverer for its utility-owned generation, for generation it  
13 purchases under third-party tolling agreements in California, and for its imports of electricity into  
14 California. The cost of allowances and offsets is a direct GHG cost. In Section V.A below, I  
15 address direct GHG compliance costs associated with SDG&E utility-owned generation plants,  
16 procurement of electricity from third parties under tolling agreements, and electricity imports  
17 attributed to SDG&E.

18 SDG&E customers also face a second type of GHG compliance cost -- indirect costs.  
19 Indirect costs are costs embedded in market electricity prices, or costs that SDG&E incurs from  
20 third parties under contracts. The party selling the power is responsible for the GHG allowance

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<sup>26</sup> ARB, Article 5: California Cap on Greenhouse Gas Emissions and Market-based Compliance Mechanisms, Section 95811(b). Available at: <https://www.arb.ca.gov/cc/capandtrade/c-t-reg-reader-2013.pdf>.

<sup>27</sup> ARB, Article 5: California Cap on Greenhouse Gas Emissions and Market-based Compliance Mechanisms, Section 95851. Available at: <https://www.arb.ca.gov/cc/capandtrade/c-t-reg-reader-2013.pdf>.

1 acquisition, but it implicitly charges SDG&E for the cost of acquiring allowances. In Section  
2 V.B below, I address indirect GHG costs. In Section V.C, I describe the calculation of both  
3 direct and indirect 2019 GHG costs. Finally, in Section V.D, I discuss the 2019 allowance  
4 auction revenues and the allocations of those revenues.

#### 5 **A. Direct GHG Emissions**

6 Each first deliverer of electricity within California must surrender to ARB one allowance  
7 or offset for each MT of carbon dioxide emissions, or its equivalent (CO<sub>2</sub>e). Under ARB's first  
8 deliverer approach, SDG&E will have a direct compliance obligation for GHG emissions from  
9 burning natural gas at facilities in its portfolio, including carbon dioxide, methane, and nitrous  
10 oxide. I forecasted SDG&E's expected direct GHG compliance costs using the same production  
11 simulation model results that produced the ERRA expenses discussed above. The amount of fuel  
12 needed for each natural gas fired plant is provided as an output based on the expected operation  
13 of the plant, including fuel associated with starts. The fuel volume is then multiplied by an  
14 emissions factor of 0.05307 MT of CO<sub>2</sub>e per MMBtu to calculate direct emissions obligations  
15 for each plant.<sup>28</sup> The forecast of GHG emissions from SDG&E facilities in 2019 is included in  
16 Table 4 below.

17 Similarly, the estimated emissions for tolling agreements (*e.g.*, Otay Mesa) are estimated  
18 by multiplying the forecast of MMBtu of natural gas burned from the production simulation by  
19 the emission factor of 0.05307 MT of CO<sub>2</sub>e per MMBtu. Table 4 below provides the forecast of

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<sup>28</sup> ARB's Mandatory Reporting Regulations requires use of emission factors from federal regulations - 40 Code of Federal Regulations ("C.F.R.") Section 98. For pipeline natural gas, there are three components – CO<sub>2</sub>, CH<sub>4</sub>, and NO<sub>2</sub>. Table C-1 of 40 C.F.R. Section 98 provides an emissions rate for CO<sub>2</sub> of 0.05302 MT/MMBtu. Table C-2 of 40 C.F.R. Section 98 gives a default emission factor for CH<sub>4</sub> of 0.000001 MT/MMBtu. Using a Global Warming Potential of 21, the resulting CO<sub>2</sub>e emission rate is 0.00002 MT/MMBtu. The default NO<sub>2</sub> emission rate is given as 0.0000001 MT/MMBtu, and the Global Warming Potential is 310, resulting in a CO<sub>2</sub>e emission rate of 0.00003 MT/MMBtu. Combining the 3 elements results in an overall emission rate of 0.05307 MT/MMBtu. SDG&E's portfolio of GHG emitting resources use only natural gas, and not other fuels.

1 GHG emissions from generators that are under tolling agreements with SDG&E in 2019.

2 In addition, SDG&E imports out-of-state electricity to a delivery point inside California,  
3 and it is thus responsible for the GHG emissions attributed to generation of that electricity.

4 There are three categories of GHG emissions associated with imports. First, there are imports  
5 from “specified sources” (*i.e.*, imports where the source of the power is known), which consist of  
6 either a specific plant or an asset-controlling supplier. Accordingly, power from SDG&E’s  
7 Desert Star combined-cycle generation plant in Nevada, for example, is included on the same  
8 basis as SDG&E’s other utility-owned facilities—multiplying the forecast of MMBtu of natural  
9 gas burned from the production simulation by the emission factor of 0.05307 MT of CO<sub>2e</sub> per  
10 MMBtu.<sup>29</sup> Second, imported power from “unspecified sources” is multiplied by an estimated  
11 transmission loss factor of 1.02<sup>30</sup> to estimate the MWh related to unspecified electricity imports.  
12 The quantity is multiplied by the ARB default emission rate, 0.428 metric tons of CO<sub>2e</sub> per  
13 MWh.

14 Third, electricity from out-of-state renewable resources that are not imported can be used  
15 to offset the emissions of imports under the ARB “Renewable Portfolio Standard (“RPS”)  
16 adjustment.” Specifically, the RPS adjustment is equal to the default emission rate multiplied by  
17 the MWh from the eligible renewable resources, as measured at the point of generation.<sup>31</sup>

18 Currently, SDG&E’s RPS adjustment is in dispute by ARB, so a discount of 50% was applied to  
19 reflect the potential for a reduced RPS adjustment. Both the emissions of imported power and  
20 the offsetting RPS adjustment are shown in Table 4 below. Monthly emissions for all categories

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<sup>29</sup> SDG&E currently does not have any contracts with asset-controlling suppliers such as the Bonneville Power Administration or Powerex. ARB assigns an emissions factor based on the entire portfolio for these suppliers.

<sup>30</sup> Transmission losses on SDG&E’s system are measured at approximately 2% of load requirement.

<sup>31</sup> ARB, Article 5: California Cap on Greenhouse Gas Emissions and Market-based Compliance Mechanisms, Section 95852(b)(4)(C). Available at: <https://www.arb.ca.gov/cc/capandtrade/c-t-reg-reader-2013.pdf>.

1 are summarized in Attachment E.

## 2 **B. Indirect GHG Emissions**

3 In addition to the direct GHG costs described above, the cap-and-trade program results in  
4 GHG compliance costs being embedded in the market price of electricity procured in the  
5 wholesale market and from third parties. The cost to purchase electricity from the wholesale  
6 market, as well as from suppliers under contracts that include market-based prices, will have  
7 these embedded costs of compliance with the cap-and-trade program built into the electricity  
8 price. The compliance instrument will be procured by the first deliverer, rather than by SDG&E,  
9 as purchaser. SDG&E's expected indirect GHG compliance costs are based on an assumption  
10 that all power sold by SDG&E-controlled assets are used by SDG&E customers, up to the level  
11 of the forecasted SDG&E load.<sup>32</sup> If the total CAISO market purchases exceed the MWh from  
12 SDG&E-controlled generation, then the assumption is that SDG&E entered into market  
13 purchases to cover this difference. To estimate the GHG emissions embedded in these net  
14 CAISO market purchases, SDG&E used the ARB's default emissions rate, 0.428 MT per MWh.

15 In addition to market purchases, contracts with some Combined Heat and Power ("CHP")  
16 facilities are included as indirect costs. Specific CHP contracts require payments based on a  
17 market electricity price (with embedded GHG costs), or a fixed heat rate with the GHG cost  
18 based on the contract heat rate; or in other cases, a reimbursement of GHG expenditures incurred  
19 by the CHP facility associated with sales to SDG&E. These contracts represent a second source  
20 of indirect GHG costs in that the CHP owner acquires GHG compliance instruments.

21 Contractual GHG costs do not provide a good estimate of actual GHG costs.

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<sup>32</sup> In fact, however, the generation is bid into the CAISO market and dispatched by CAISO to meet statewide needs. The simplifying assumption is used to calculate net CAISO market purchases – all CAISO purchases less all resources that are forecasted to successfully bid into the CAISO market by SDG&E, including imports. However, SDG&E does make an adjustment for expected sales of renewable energy beyond regulatory requirements.

1 Determining actual GHG costs however, is difficult because it requires knowledge of  
 2 confidential counterparty data and the choice of method used to split the GHG emissions  
 3 between electricity production and useful thermal energy. For simplicity, SDG&E estimates  
 4 GHG costs associated with CHP on the assumption that the CHP units, on average, are as  
 5 efficient as unspecified power, assigning a 0.428 MT per MWh emissions rate to all purchases of  
 6 power from CHP facilities. The GHG emissions from indirect sources are summarized on an  
 7 annual basis in Table 4 and on a monthly basis in Appendix E.

<b>Table 4: 2019 GHG Total Emissions Forecast</b>		
<b>Resource</b>	<b>Fuel (000 MMBtu)</b>	<b>GHG (000 Metric Tons)</b>
Palomar- UOG		
Otay Mesa- PPA		
Otay Mesa - UOG		
Desert Star- Out of State		
Goal Line- PPA		
Orange Grove-PPA		
Escondido Energy Center-PPA		
Pio Pico- PPA		
Carlsbad Energy Center- PPA		
Naval Station - PPA		
North Island - PPA		
Miramar- UOG		
Yuma- PPA Out of State		
<b>Fuel-Based</b>		
	<b>Generation (GWh)</b>	
Imports		
RPS Adjustment		
<b>Total Direct Emissions</b>		
<b>Resource</b>	<b>Generation (GWh)</b>	
Net Market Purchases		
CHP		
<b>Total Indirect Emissions</b>		
<b>Total Forecasted Emissions</b>		<b>3,824</b>
<b>Conversions</b>		
<b>Natural Gas</b>	0.05307 MTons/MMBtu	
<b>Market Purchases</b>	0.428 MTons/MWh	
<b>Imports</b>	0.428 MTons/MWh	

8



1           **C.     2019 GHG Costs**

2           I calculated a proxy for the 2019 GHG emissions price as \$15.74/MT. This figure was  
3 derived using a recent (March 1, 2018) assessment of 2019 GHG market prices based on the  
4 average of forward prices on the Intercontinental Exchange (“ICE”) over the previous 22-day  
5 period, consistent with the period used for forecasting natural gas and electricity prices  
6 associated with the forecast of emissions in Table 4. The GHG cost forecast multiplies the  
7 expected emissions, both direct and indirect, by the forecasted proxy GHG price resulting in  
8 forecasted GHG costs for 2019 of \$49.8 million for ERRA and \$10.4 million for Local  
9 Generation.

10           **D.     2019 Allowance Auction Revenues**

11           The ARB allocates cap-and-trade allowances to SDG&E for 2019. SDG&E is required  
12 to place all of these allowances for sale in ARB’s 2019 quarterly auctions. I developed the  
13 forecast of allowance revenues by multiplying the total number of allowances allocated to  
14 SDG&E for consignment by a forecast price for the allowances.<sup>33</sup>

15           Under ARB’s regulations, the allowances available for allocation to electrical distribution  
16 utilities each budget year is currently 97.7 million MT multiplied by the cap adjustment factor  
17 (0.869 (for 2019)), and SDG&E’s share of electric sector allowances (7.2872% (for 2019)).<sup>34</sup>  
18 The total allowances that will be allocated to SDG&E for 2019 is expected to be 6,186,936 MT.  
19 The allowance price is the same proxy price as used in the calculation of GHG costs, \$15.74/MT.  
20 The allowance auction revenue forecast is the allowances allocated times the allowance price or  
21 \$97.4 million.

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<sup>33</sup> I assumed all allowances are sold in the auction process, which is consistent with the assumption that the market-clearing price is above the price floor.

<sup>34</sup> ARB, Cap-and-Trade Regulation, Section 95891 at Tables 9-2 and 9-3.

1           The available funds reserved for the clean energy and energy efficiency programs are  
2 equal to 15 percent of the forecasted 2019 allowance auction revenue amount or \$14.6 million.

3           Section 2870 allocates a portion of the allowance auction revenue reserved for clean  
4 energy and energy efficiency projects to the Solar on Multifamily Affordable Housing  
5 (“SOMAH”) Program. Consistent with AB 693, this program provides financial incentives for  
6 installation of solar energy systems on multifamily affordable housing properties, as specified in  
7 the statute. For 2019, the funding amount is \$9.7 million which is 10% of the forecasted 2019  
8 allowance auction revenue amount described in Section 2870.

## 9 **VI. CONCLUSION**

10           In conclusion, SDG&E requests that the Commission approve the forecasts provided in  
11 my testimony for use in developing the ERRA, TCBA, LG and SONGS Unit 1 Offsite Spent  
12 Fuel Storage Cost revenue requirements. SDG&E also requests that the Commission authorize  
13 recovery of the forecasted 2019 GHG costs, which are also used in determining the revenue  
14 requirement, and the volumetric revenue return for small business and residential customers.  
15 This concludes my direct testimony.

## 16 **VII. QUALIFICATIONS**

17           My name is Jennifer Montanez. My business address is 8330 Century Park Court, San  
18 Diego, California, 92123. I received a B.S. in Business Administration, with an emphasis in  
19 Accounting, from California State University San Marcos.

20           I have been employed as a Senior Resource Planner in the Resource Planning group of  
21 SDG&E since 2016. Prior to that, I was employed in positions of increasing responsibility in the  
22 following SDG&E departments: Electric & Fuel Procurement and Energy Risk Management. I

1 also served as an accountant for various Sempra Energy business units for five years. I have  
2 been employed with Sempra Energy Company or SDG&E for 11 years.



# Attachment B

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

ATTACHMENT B - SDG&E 2019 GENERATION PORTFOLIO DELIVERY VOLUMES (GWh)													
	Jan	Feb	Mar	Apr	May	Jun	Jul	Aug	Sep	Oct	Nov	Dec	2019
CTC QF													
Non-CTC QF													
<b>TOTAL QF</b>													
Renewable - Bio Gas	14.7	12.7	15.1	13.4	14.4	13.6	16.0	16.7	17.8	15.9	15.6	16.0	181.9
Renewable - Other	-	-	-	-	-	-	0.6	0.7	0.6	0.1	-	-	2.0
Renewable - Solar	214.6	250.5	320.7	351.0	382.9	373.1	360.1	351.6	307.8	286.9	225.4	201.0	3,625.5
Renewable - Wind	118.8	116.8	178.2	213.9	234.1	206.6	181.9	144.2	126.9	126.0	106.0	121.0	1,874.3
Renewable - Wind REC	110.3	155.1	134.5	93.6	78.4	91.9	73.7	63.6	100.9	84.5	119.4	130.0	1,236.0
Renewable - RPS Sales	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	-
<b>TOTAL NON-QF RENEWABLE</b>	<b>458.3</b>	<b>535.0</b>	<b>648.5</b>	<b>671.9</b>	<b>709.8</b>	<b>685.2</b>	<b>632.3</b>	<b>576.9</b>	<b>553.9</b>	<b>513.5</b>	<b>466.4</b>	<b>468.0</b>	<b>6,919.6</b>
Miramar													
Miramar 2													
Cuyamaca													
Palomar													
Otay Mesa Energy Center													
Desert Star													
Kelco													
Lake Hodges													
BP													
Morgan Stanley													
El Cajon Energy Center													
Orange Grove													
Escondido Energy Center													
Pio Pico													
Carlsbad Energy Center													
AMS Energy Storage													
Naval Station													
North Island													
El Cajon Energy Storage													
EPC Energy Storage													
Escondido Energy Storage													
RPS Sales Residual Generation	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	-
<b>TOTAL GENERATION</b>													
Market Purchases													
<b>TOTAL PORTFOLIO DELIVERIES</b>													
Surplus Energy Sold													
Energy Storage Charging Load													
<b>LOAD REQUIREMENT (GWh)</b>													
<p>Note 1: Total Portfolio Deliveries do not include Wind REC</p> <p>Note 2: Load Requirement is SDG&amp;E bundled load including transmission losses</p>													

# Attachment C

**ATTACHMENT C - SDG&E 2019 RENEWABLE RESOURCE DETAIL**

Power Purchase Deliveries (GWh)	Jan	Feb	Mar	Apr	May	Jun	Jul	Aug	Sep	Oct	Nov	Dec	2019
<b>BIO GAS</b>													
Lakeside BioGas LLC	-	-	-	-	-	-	-	0.6	2.2	2.1	2.0	2.0	8.8
MM Prima Deshecha Energy LLC	6.0	5.7	6.6	5.7	6.5	6.3	7.3	7.2	7.0	6.1	6.4	6.3	77.0
MM San Diego LLC- Miramar Landfill	2.5	2.0	2.4	2.3	2.5	2.2	3.0	2.9	2.9	2.4	2.3	2.4	29.8
BIOGAS FIT	6.2	5.1	6.1	5.4	5.4	5.2	5.7	6.0	5.7	5.4	5.0	5.3	66.4
<b>Subtotal</b>	<b>14.7</b>	<b>12.7</b>	<b>15.1</b>	<b>13.4</b>	<b>14.4</b>	<b>13.6</b>	<b>16.0</b>	<b>16.7</b>	<b>17.8</b>	<b>15.9</b>	<b>15.6</b>	<b>16.0</b>	<b>181.9</b>
<b>OTHER</b>													
SMALL HYDRO RAM	-	-	-	-	-	-	0.6	0.7	0.6	0.1	-	-	2.0
<b>Subtotal</b>	<b>-</b>	<b>-</b>	<b>-</b>	<b>-</b>	<b>-</b>	<b>-</b>	<b>0.6</b>	<b>0.7</b>	<b>0.6</b>	<b>0.1</b>	<b>-</b>	<b>-</b>	<b>2.0</b>
<b>SOLAR</b>													
NRG Borrego Solar	3.6	4.5	6.4	7.1	7.7	7.9	7.8	7.3	5.9	5.3	4.1	2.9	70.4
Sol Orchard	1.6	2.2	3.0	3.3	2.9	3.6	3.7	3.5	2.8	2.5	2.0	1.7	32.7
Solar Energy Project	0.8	0.8	1.1	1.1	1.1	1.1	1.1	1.1	1.0	0.9	0.8	0.8	11.4
SOLAR PV FIT	0.9	1.0	1.3	1.3	1.4	1.3	1.2	1.3	1.2	1.2	0.9	0.9	13.7
Arlington Valley Solar	19.9	24.3	33.1	36.5	40.3	40.0	38.1	36.4	31.3	28.4	21.8	19.2	369.2
Callipatria	3.0	3.2	5.3	5.3	6.0	5.8	5.2	5.5	5.2	4.1	3.6	2.6	54.8
Campo Verde	24.3	27.0	33.3	33.8	35.3	33.2	31.5	33.1	30.3	30.6	24.6	23.2	360.2
Catalina Solar	15.9	19.2	23.8	24.0	26.8	26.6	27.0	26.1	24.4	21.7	19.3	16.9	271.6
Centinela Solar1	21.4	25.2	31.4	36.6	40.6	40.0	38.7	36.9	31.6	28.8	21.7	19.6	372.4
Centinela Solar2	7.7	9.1	11.3	13.2	14.6	14.4	13.9	13.3	11.4	10.4	7.8	7.0	134.1
Desert Green	0.7	1.0	1.3	1.4	1.4	1.5	1.5	1.5	1.2	1.2	0.9	0.7	14.3
Imperial Valley Solar I	30.0	36.6	48.4	55.9	63.1	61.4	59.5	55.9	45.5	41.9	31.2	26.4	555.6
Maricopa West Solar	3.0	3.2	5.3	5.3	6.0	5.8	5.2	5.5	5.2	4.1	3.6	2.6	54.8
Midway Solar	2.7	2.8	4.7	5.1	5.7	5.5	5.2	4.2	4.3	3.8	2.5	2.3	48.7
TallBear Seville	3.4	4.0	5.0	5.9	6.5	6.4	6.2	5.9	5.1	4.6	3.5	3.1	59.6
SolarGen 2	25.7	30.3	37.7	43.9	48.7	48.0	46.4	44.3	37.9	34.5	26.0	23.5	446.9
Cascade SunEdison	2.9	3.8	5.0	5.2	6.1	6.1	5.9	5.5	4.8	4.2	3.2	2.9	55.5
Csolar IV South	20.9	23.2	27.5	29.7	30.7	28.7	28.2	28.6	26.4	26.0	21.4	19.7	311.1
Csolar IV West	26.2	29.2	35.9	36.5	38.1	35.9	33.9	35.8	32.7	33.0	26.5	25.1	388.7
<b>Subtotal</b>	<b>214.6</b>	<b>250.5</b>	<b>320.7</b>	<b>351.0</b>	<b>382.9</b>	<b>373.1</b>	<b>360.1</b>	<b>351.6</b>	<b>307.8</b>	<b>286.9</b>	<b>225.4</b>	<b>201.0</b>	<b>3,625.5</b>
<b>WIND</b>													
Glacier Wind (TREC)	49.4	80.9	63.3	43.0	37.5	44.7	36.2	31.0	48.3	35.4	48.1	61.2	578.8
Rim Rock (TREC)	60.8	74.2	71.3	50.6	40.9	47.2	37.5	32.6	52.6	49.1	71.4	68.8	657.2
Kumeyaay	12.5	12.9	14.5	12.1	13.7	11.5	10.2	7.3	7.5	6.9	8.9	15.5	133.6
Coram Energy	1.2	1.4	2.5	2.9	3.1	3.2	2.7	2.2	1.6	1.6	1.5	1.7	25.7
Energia Sierra Juarez	44.5	34.3	41.7	46.2	44.5	35.4	28.3	21.6	30.3	32.3	35.1	34.7	428.7
Manzana Wind	12.5	14.6	23.5	27.9	30.4	35.3	28.5	23.8	9.9	11.0	9.7	16.8	244.0
Oak Creek Wind Power	0.2	0.3	0.6	0.7	0.7	0.8	0.5	0.5	0.3	0.4	0.3	0.3	5.4
Oasis Power Partners	6.9	8.6	15.8	18.2	20.2	21.7	20.4	17.0	11.1	11.3	9.3	9.5	170.1
Ocotillo Express	24.6	25.9	48.8	68.6	81.0	57.1	58.4	44.2	45.2	39.8	22.0	18.9	534.6
Pacific Wind	15.1	17.2	27.7	33.9	36.7	37.6	29.0	24.4	18.9	20.8	17.5	21.6	300.3
San Geronio	1.3	1.6	3.0	3.4	3.8	4.1	3.8	3.2	2.1	2.1	1.7	1.9	31.9
<b>Subtotal</b>	<b>229.1</b>	<b>271.9</b>	<b>312.7</b>	<b>307.5</b>	<b>312.5</b>	<b>298.6</b>	<b>255.6</b>	<b>207.9</b>	<b>227.7</b>	<b>210.6</b>	<b>225.4</b>	<b>251.0</b>	<b>3,110.2</b>
<b>RPS SALES</b>													
<b>Subtotal</b>	<b>-</b>	<b>-</b>	<b>-</b>	<b>-</b>	<b>-</b>	<b>-</b>	<b>-</b>	<b>-</b>	<b>-</b>	<b>-</b>	<b>-</b>	<b>-</b>	<b>-</b>
<b>Total Power Purchase Costs (\$000)</b>													
BIO GAS	\$ 1,223	\$ 1,039	\$ 1,244	\$ 1,108	\$ 1,170	\$ 1,099	\$ 1,299	\$ 1,393	\$ 1,566	\$ 1,415	\$ 1,345	\$ 1,385	\$ 15,288
OTHER	\$ -	\$ -	\$ -	\$ -	\$ -	\$ -	\$ 46	\$ 58	\$ 46	\$ 12	\$ -	\$ -	\$ 161
SOLAR	\$ 22,563	\$ 26,479	\$ 33,953	\$ 36,262	\$ 39,977	\$ 39,251	\$ 49,635	\$ 50,943	\$ 42,665	\$ 40,675	\$ 23,581	\$ 20,711	\$ 426,694
WIND	\$ 10,709	\$ 10,514	\$ 16,372	\$ 19,970	\$ 21,944	\$ 19,222	\$ 18,129	\$ 14,573	\$ 13,225	\$ 13,348	\$ 9,611	\$ 10,792	\$ 178,407
WIND (REC)	\$ 3,944	\$ 5,333	\$ 4,754	\$ 3,318	\$ 2,756	\$ 3,235	\$ 2,578	\$ 2,225	\$ 3,546	\$ 3,061	\$ 4,371	\$ 4,586	\$ 43,707
RPS SALES	\$ -	\$ -	\$ -	\$ -	\$ -	\$ -	\$ -	\$ -	\$ -	\$ -	\$ -	\$ -	\$ -
<b>Subtotal</b>	<b>\$ 38,440</b>	<b>\$ 43,365</b>	<b>\$ 56,324</b>	<b>\$ 60,657</b>	<b>\$ 65,846</b>	<b>\$ 62,807</b>	<b>\$ 71,687</b>	<b>\$ 69,192</b>	<b>\$ 61,048</b>	<b>\$ 58,511</b>	<b>\$ 38,908</b>	<b>\$ 37,475</b>	<b>\$ 664,258</b>



## **GLOSSARY OF ACRONYMS**

AB: Assembly Bill

ARB: California Air Resource Board

A/S: Ancillary Services

CAISO: California Independent System Operator

CEC: California Energy Commission

CHP: Combined Heat and Power

CO<sub>2</sub>e: Carbon Dioxide Emissions

CRR: Congestion Revenue Rights

CTC: Competition Transition Charge

Desert Star: Desert Star Energy Center

DLAP: Default Load Aggregation Point

ECR: Enhanced Community Renewables

ERRA: Energy Resource Recovery Account

FERC: Federal Energy Regulatory Commission

FF&U: Franchise Fee and Uncollectible

GHG: Greenhouse Gas

GMC: Grid Management Charges

GT: Green Tariff

GTSR: Green Tariff Shared Renewable

GWh: Gigawatt Hours

ICE: Intercontinental Exchange

ISO: Independent System Operator

IST: Inter-Scheduling Coordinator Trades

LG: Local Generation

LGBA: Local Generation Balancing Account

O&M: Operating and Maintenance



OMECE: Otay Mesa Energy Center  
MIRAMAR I: Miramar Energy Facility I  
MIRAMAR II: Miramar Energy Facility II  
MMBtu: Million British Thermal Units  
MPB: Market Price Benchmark  
MRTU: Market Redesign and Technology Upgrade  
MT: Metric Ton  
MW: Megawatt  
MWh: Megawatt Hour  
NOB: Northern Oregon Border  
Palomar: Palomar Energy Center  
PCIA: Power Charge Indifference Adjustment  
PPA: Power Purchase Agreement  
PURPA: Public Utility Regulatory Policies Act  
QFs: Qualifying Facilities  
REC: Renewable Energy Credit  
RPS: Renewables Portfolio Standard  
SCE: Southern California Energy Company  
SDG&E: San Diego Gas & Electric Company  
SOMAH: Solar on Multifamily Affordable Housing  
SRAC: Short-Run Avoided Cost  
SONGS: San Onofre Nuclear Generating Station  
TCBA: Transition Cost Balancing Account  
WREGIS: Western Renewable Energy Generation Information System  
YCA: Yuma Cogeneration Associates

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

**DECLARATION OF ROBERT B. ANDERSON  
REGARDING CONFIDENTIALITY OF CERTAIN DATA/DOCUMENTS  
PURSUANT TO D.16-08-024, *et al.***

I, Robert B. Anderson, do declare as follows:


1. I am a Director in the Resource Planning department for San Diego Gas & Electric Company ("SDG&E"). I have been delegated authority to sign this declaration by Emily C. Shults, Vice President of Energy Supply. I have reviewed Jennifer Montanez's Prepared Direct Testimony ("Testimony") in support of SDG&E's "Application ... for Approval of its 2019 Electric Procurement Revenue Requirement Forecasts and GHG-Related Forecasts" ("Application"). I am personally 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 my personal knowledge and/or information and belief.

2. I hereby provide this Declaration in accordance with Decisions ("D.") 16-08-024, D.17-05-035, and D.17-09-023 to demonstrate that the confidential information ("Protected Information") provided in the Testimony is within the scope of data protected as confidential under applicable law.

3. In accordance with the legal authority described herein, the Protected Information should be protected from public disclosure.

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

Executed this 13th day of April, 2018, at San Diego.

  
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Robert B. Anderson (Director)

# ATTACHMENT A

## SDG&E Request for Confidentiality on the following information in its Application for Approval of Its 2018 Electric Procurement Revenue Requirement Forecasts and GHG- Related Forecasts

Location of Protected Information	Legal Authority	Narrative Justification
JRM-21 Table 4 Application Attachment G, Template D-2: Forecasted Emissions and Costs; and Template D-5: Forecasted Emissions Intensity  Attachment E - SDG&E Greenhouse Gas (GHG) Detail	D.14-10-033; D.16-08-024; D.17-05-035; D.17-09-023; Public Utilities Code Section 454.5(g).	The information does not expressly fall within any category of the IOU Matrix applicable to electric procurement information, but is market-sensitive information in that providing these GHG emissions forecasts to market participants would allow them to know SDG&E's forecasted GHG obligation, thereby compromising SDG&E's contractual bargaining power such that customer costs are likely to rise. Thus, the release of this non-public confidential information will unjustifiably allow market participants to use this information to the disadvantage of SDG&E's customers.

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

**DECLARATION  
OF JENNIFER R. MONTANEZ**

**A.18-04-\_\_**

Application of San Diego Gas & Electric Company (U 902-E)  
for Approval of Its 2019 Electric Procurement Revenue Requirement Forecasts and GHG-  
Related Forecasts

I, Jennifer R. Montanez, declare as follows:

1. I am a Senior Resource Planner for San Diego Gas & Electric Company (“SDG&E”). I included my Prepared Direct Testimony (“Testimony”) in support of SDG&E’s April 13, 2018 Application for Approval of its 2019 Electric Procurement Revenue Requirement Forecasts and GHG-Related Forecasts (“Application”). Additionally, as a Senior Resource Planner, 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). 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;
- 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 my Testimony constitutes material, market sensitive, electric procurement-related information that is within the scope of Section 454.5(g) of the Public Utilities Code.<sup>1</sup> As such, the Protected Information is allowed confidential treatment in accordance with the Matrix, as follows:

<b>Confidential Information</b>	<b>Matrix Reference</b>	<b>Reason for Confidentiality and Timing</b>
JRM-3 lines 7-8	V.C	LSE Total Energy Forecast – Bundled Customer; confidential for the front three years
JRM-5 Table 1	IV.F	Forecast of Post-1/1/2003 Bilateral Contracts; confidential for three years
JRM-5 line 7	VI.A	Utility Bundled Net Open Position for Capacity; confidential for the front three years
JRM-6 Table 2	IV.A	Forecast of IOU Generation Resources; confidential for three years
JRM-6 line 14	V.H	Net capacity and energy forecasts by retail provider; confidential for the front three years
JRM-8 line 12	IV.B	Forecast of Qualifying Facility Generation; confidential for three years
JRM-9 line 3	IV.J	Forecast of Wholesale Market Purchases; confidential for the front three years
JRM-9 line 18	II.A.2, V.C	Utility Electric Price Forecasts; confidential for three years, LSE Total Energy Forecast, confidential for the front three years
JRM-10 line 4	II.A.2, II.B.1, II.B.3, II.B.4	Utility Electric Price Forecasts; confidential for three years, Generation Cost Forecasts of Utility Retained Generation, confidential for three years, Generation Cost Forecasts of QF Contracts, confidential for three years, Generation Cost Forecasts of Non-QF Bilateral Contracts, confidential for three years
JRM-10 lines 8, 11-13 JRM-13 line 7	II.B.4	Generation Cost Forecast of Non-QF Bilateral Contracts; confidential for three years
JRM-12 line 5	II.B.3	Generation Cost Forecast of QF Contracts; confidential for three years

<sup>1</sup> 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-C. Accordingly, SDG&E seeks confidential treatment of this data under those provisions, as applicable.

<b>Confidential Information</b>	<b>Matrix Reference</b>	<b>Reason for Confidentiality and Timing</b>
JRM-12 line 14	II.B.1	Generation Cost Forecasts of Utility Retained Generation, confidential for three years
JRM-13 lines 11 and 13	II.A.2	Utility Electric Price Forecasts; confidential for three years
JRM-13 line 20 JRM-21 Table 4	I.A.4	Long-term Fuel (gas) Buying and Hedging; confidential for three years
JRM-21 Table 4		GHG emissions forecast: Providing these forecasts to market participants would allow them to know SDG&E's GHG forecasted GHG obligation, thereby compromising SDG&E's contractual bargaining power such that customer costs are likely to rise. Thus, the release of this non-public confidential information will unjustifiably allow market participants to use this information to the disadvantage of SDG&E's customers.
Attachment A - SDG&E 2019 ERRA and LG Expenses	XI	Monthly Procurement Costs; confidential for three years
Attachment B - SDG&E 2019 Generation Portfolio Delivery Volumes <ul style="list-style-type: none"> <li>• Cuyamaca, Palomar, Desert Star, and Miramar data</li> <li>• QF data</li> <li>• Otay Mesa, Celerity, Kelco, Lake Hodges, Wellhead, and Orange Grove data</li> <li>• Market Purchase data</li> <li>• Surplus Energy Sold data</li> </ul> Load Requirement data	IV.A IV.E IV.B IV.F IV.J IV.K V.C	Forecast of IOU Generation Resources; confidential for three years Forecast of Pre-1/1/2003 Bilateral Contracts; confidential for three years Forecast of Qualifying Facility Generation; confidential for three years Forecast of Post-1/1/2003 Bilateral Contracts; confidential for three years Forecast of Wholesale Market Purchases; confidential for the front three years Forecast of Wholesale Market Sales; confidential for the front three years LSE Total Energy Forecast – Bundled Customer; confidential for the front three years

Confidential Information	Matrix Reference	Reason for Confidentiality and Timing
<p>Attachment D - SDG&amp;E 2019 CTC Qualifying Facility (QF) Detail</p> <ul style="list-style-type: none"> <li>• QF data</li> <li>• Long-Term Power Purchase CTC data</li> <li>• CTC QF &amp; Non CTC QF data</li> <li>• TCBA Expenses data</li> </ul>	<p>IV.E IV.B II.B.4 II.B.3 II.B.3 and II.B.4</p>	<p>Forecast of Pre-1/1/2003 Bilateral Contracts; confidential for three years Forecast of Qualifying Facility Generation; confidential for three years Generation Cost Forecast of Non-QF Bilateral Contracts; confidential for three years Generation Cost Forecast of QF Contracts; confidential for three years Generation Cost Forecast of QF Contracts; confidential for three years Generation Cost Forecast of Non-QF Bilateral Contracts; confidential for three years</p>
<p>Attachment E - SDG&amp;E Greenhouse Gas (GHG) Detail</p>		<p>GHG emissions forecasts: Providing these forecasts to market participants would allow them to know SDG&amp;E's GHG forecasted GHG obligation, thereby compromising SDG&amp;E's contractual bargaining power such that customer costs are likely to rise. Thus, the release of this non-public confidential information will unjustifiably allow market participants to use this information to the disadvantage of SDG&amp;E's customers.</p>


4. I am not aware of any instances where the Protected Information has been disclosed to the public. To my knowledge, no party, including SDG&E, has publicly revealed any of the Protected 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.

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

Executed this 13th day of April, 2018, at San Diego, California.

  
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Jennifer R. Montanez  
Senior Resource Planner  
San Diego Gas & Electric Company