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Witness: Benjamin A. Montoya

PREPARED DIRECT TESTIMONY OF

BENJAMIN A. MONTOYA

ON BEHALF OF

SAN DIEGO GAS & ELECTRIC COMPANY

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

BEFORE THE PUBLIC UTILITIES COMMISSION
OF THE STATE OF CALIFORNIA

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I. INTRODUCTION

My testimony describes the resources San Diego Gas & Electric Company ("SDG&E") expects to use in calendar year 2017 to provide electric commodity service to its bundled service customers; provides a forecast of the procurement costs that SDG&E expects to record in 2017 to the Energy Resource Recovery Account ("ERRA"), Transition Cost Balancing Account ("TCBA"), and Local Generation Balancing Account ("LGBA"); provides a 2017 forecast of SDG&E's San Onofre Generating Station ("SONGS") Unit 1 Offsite Spent Fuel Storage Costs; and provides a forecast of 2017 total greenhouse gas ("GHG") costs. This information is used by SDG&E witness Norma Jasso in developing the proposed total 2017 ERRA, ("Competition Transition Charge ("CTC") and Local Generation ("LG") revenue requirements and by witness Yvonne Le Mieux in developing the GHG allowance revenue return allocation and the volumetric revenue return for small business and residential customers.

In Section II of my testimony, I provide a forecast of the energy requirements that will be required to serve SDG&E's bundled customer load for 2017, as well as forecasts of the supply resources that SDG&E expects to utilize to meet that load in calendar year 2017. The supply resources for which I provide forecasts include (1) generation resources that are under contract for 2017; (2) generation resources owned by SDG&E; (3) renewable generation resources that are under contract for 2017; (4) Qualifying Facilities ("QFs") under the Public Utility Regulatory

Policies Act ("PURPA") that are under contract for 2017; and (5) generation obtained through market purchases.

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

In Section IV of my testimony, I provide a forecast of the 2017 SONGS Unit 1 Offsite Spent Fuel Storage Costs associated with SDG&E's 20% minority ownership interest in SONGS.

In Section V of my testimony, I provide a forecast of the 2017 GHG emissions and associated costs, both direct and indirect, incurred in connection with SDG&E's compliance with California's cap-and-trade program. I also provide a forecast of GHG allowance auction revenues. Lastly, I provide a statement of qualifications.

My testimony refers to the following attachments:

Attachment A: SDG&E 2017 ERRA and LG Expenses

Attachment B: SDG&E 2017 Generation Portfolio Delivery Volumes

Attachment C: SDG&E 2017 Renewable Resource Detail

Attachment D: SDG&E 2017 CTC & QF Detail

Attachment E: SDG&E GHG Detail.

SDG&E requests that the Commission approve the forecasts I provide for use in developing the ERRA, CTC, LG and SONGS Unit 1 Offsite Spent Fuel Storage Costs revenue requirements. SDG&E also requests that the Commission authorize recovery of the forecasted

2017 GHG costs, which are also used in determining the revenue requirement, and the volumetric revenue return for small business and residential customers.

II. 2017 FORECAST OF ENERGY REQUIREMENTS AND SUPPLY RESOURCES

A. ENERGY REQUIREMENTS FORECAST

As a starting point for my analysis, I developed a forecast of SDG&E's 2017 bundled load requirement, which is based on SDG&E's General Rate Case ("GRC") Phase 2 forecast. Using this forecast and adjusting for direct access load, I project that the energy requirements for its bundled load for 2017 will be [redacted]. This forecast is [redacted] or [redacted] less than SDG&E's forecasted bundled energy forecast for 2016 ([redacted]).

B. SUPPLY RESOURCE FORECAST

After determining the amount of energy that SDG&E's bundled load customers will require in 2017, I then proceeded to develop a forecast of the supply resources that will be needed to meet that demand, which fall into the following five categories.

1. SDG&E-Contracted Generation

SDG&E has a number of generation resources under contract in its 2017 resource portfolio. These resources are available under a variety of contractual arrangements, including tolling contracts, fixed energy contracts, and contracts for Resource Adequacy only. The largest of the tolling and fixed energy contracts are:

- the Otay Mesa Energy Center ("OMEC") Power Purchase Agreement ("PPA") for the output of a 604 MW combined-cycle power plant;
- the Orange Grove PPA for the output of two 49.5 MW simple cycle combustion turbine units;

- the El Cajon Energy Center PPA for the output of a 48 MW simple cycle combustion turbine unit;
- the Escondido Energy Center PPA for the output of a 45 MW simple cycle combustion turbine unit;
- the BP PPA, which provides firmed and shaped deliveries at the SDG&E Default Load Aggregation Point (DLAP)
- the Morgan Stanley PPA, which provides firmed and shaped deliveries at the Northern Oregon Border ("NOB").

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

	Table 1: Generation (GWh)		
	2017	2016	Difference
OMEC	[redacted]		
Orange Grove			
El Cajon Energy Center			
Escondido Energy Center			
BP			
Morgan Stanley NOB			
Total			

SDG&E also enters into contracts each year to meet its CPUC Resource Adequacy requirements.[1] Under its Resource Adequacy contracts, SDG&E is entitled to show this capacity as meeting its Resource Adequacy obligation, but SDG&E does not have rights to the energy or ancillary services from these units. For 2017, SDG&E forecasts that it will enter into contracts for up to [redacted] of Resource Adequacy capacity.[2]

[1] CA P.U. 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.

[redacted]

2. SDG&E-Owned Dispatchable Generation

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

- the Palomar Energy Center ("Palomar"), a 575 MW combined cycle power plant;
- the Desert Star Energy Center ("Desert Star"), a 419 MW combined cycle power plant;
- the Miramar Energy Facility ("Miramar I and II"), consisting of two 48 MW simple cycle combustion turbine units; and
- the Cuyamaca Peak Energy Plant, consisting of a 45 MW simple cycle combustion turbine.

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

	Table 2: Generation (GWh)		
	2017	2016	Difference
Palomar	[redacted]		
Desert Star			
Miramar			
Cuyamaca			
Total			

[3] 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 ERRA contribution) of using capacity for generation is equivalent to using capacity for A/S.

3. Renewable Energy Contracts

The 2017 forecast of renewable energy supply from CPUC-approved contracts is 6,839 GWh, which includes 1,120 GWh of Renewable Energy Credit ("REC") quantities[4] that are delivered to SDG&E in conjunction with existing non-renewable imports. This forecast represents an increase of 119 GWh from the forecast for 2016 (6,720 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.

For 2017, SDG&E forecasts it will receive 5,719 GWh of bundled renewable energy under 57 contracts with facilities that generate electricity using wind, solar, biogas, and hydro technologies. The forecasted generation for projects that are currently on-line and operating is derived from generation profiles based on historical data. The forecasted generation for those projects that are still under development but that are expected to begin operations in 2017[5] is based on historical data of resources that utilize similar renewable technologies.

In addition, SDG&E expects to receive 1,120 GWh of firmed-and-shaped power from three out-of-state wind projects, Rim Rock and Naturener Glacier 1 and 2 (Montana).[6] The RECs are delivered to California independently of the physical delivery of generation by the source wind projects. This is done by tagging equivalent quantities of the physical deliveries of other energy imports that SDG&E has already accounted for in its 2017 forecast. The forecasted energy mix from these renewable resources is shown in Table 3 below:

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[4] 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.

[5] 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 ERRA.

[6] The firmed-and-shaped wind power from these contracts is delivered to California through the Morgan Stanley power contract described above.

	Table 3: Generation (GWh)		
	2017	**2016**	**Difference**
Solar	3,583	3,575	8
Wind	1,969	1,982	(13)
Wind RECs	1,120	1,120	(0)
Biogas	165	184	(19)
Other	2	19	(17)
RPS Sales	-	(160)	160
Total	6,839	6,720	119

4. Qualifying Facilities Contracts

In 2017, SDG&E will have approximately 230 megawatts ("MW") of capacity under contract with eight QFs.[7] The five largest QF contracts account for 220 MW or 96% of total QF capacity. All of these QFs are located in SDG&E's service area except for the Yuma Cogeneration Associates ("YCA") plant, a 56.5 MW natural gas-fired plant located in Arizona, the output of which is imported into the CAISO.

SDG&E's QF contracts include a combination of must-take and dispatchable resources. For must-take resources, SDG&E is obligated to pay the contract price for all delivered QF generation and schedule it into the CAISO market; SDG&E has no such obligation with dispatchable resources. SDG&E has received approval for contract amendments with two QF's: Goal Line and YCA. These amendments provide SDG&E with more economic dispatch rights. SDG&E forecasted the plants' dispatch in accordance with these terms. The forecast of QF energy supply in 2017 is [redacted], which is approximately [redacted] GWh less than the forecasted amount for 2016. The forecasted generation for these plants is detailed in Attachment D.

[7] 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 eight QFs referenced above deliver net energy to SDG&E and are thus included in the model.

5. Market Purchases and Surplus Sales

Under the Market Redesign and Technology Upgrade ("MRTU"),[8] there is no requirement that SDG&E must balance its bundled load and its controlled generation quantities that clear the market. If, in any hour, the quantity of SDG&E's bundled load requirements purchased from the CAISO is greater than SDG&E-controlled generation sold to the CAISO, the difference may be viewed as equivalent to a market purchase.[9] SDG&E forecasts that the quantity of equivalent market purchases will be [redacted] in 2017, an increase of [redacted] from the 2016 forecast ([redacted]).

III. 2017 FORECAST OF ERRA EXPENSES

In order to quantify the costs associated with the supply resources described in Section II, I used a production cost model. Inputs to this model include the characteristics of the various generation resources, including heat rate, variable Operating and Maintenance ("O&M") costs, and other factors that impact the plant's dispatch, and natural gas and market prices. The natural gas and market price forecasts were derived using a recent (March 1, 2016) assessment of 2017 market prices that is based on the average of forward prices over the previous 22 market trading days. I then run the model which simulates a least-cost dispatch of the portfolio of SDG&E's resources for every hour of 2017. The model tracks the costs of this dispatch.

In addition, electric procurement expenses incurred by SDG&E to serve its bundled load are also recorded to the ERRA. These expenses include, among other items, costs and revenues for energy and capacity cleared through the CAISO market, power purchase contract costs,

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[8] 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.

[9] 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 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.

generation fuel costs, market energy purchase costs, CAISO charges, brokerage fees, and hedging costs.

I expect that SDG&E will incur $1.279 billion of ERRA costs in 2017,[10] as reflected in Attachment A. This forecast is $14 million less than the $1.293 billion forecasted for 2016. The key driver behind the lower forecast for 2017 is lower natural gas prices.

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

A. ISO LOAD CHARGES

The CAISO supplies and sells to SDG&E the energy and A/S necessary to meet SDG&E's bundled load requirement. Based on forecasted prices for energy and A/S, SDG&E's production cost model forecasts [redacted] of ISO load charges for 2017. This cost includes the indirect GHG costs embedded in the market price of energy. I present GHG quantities and costs in Section V.

B. ISO SUPPLY REVENUES

In the CAISO market, all generation from SDG&E's resource portfolio is sold to the CAISO. Based on forecasted prices for energy, SDG&E's production cost model forecasts revenues totaling [redacted] for generation sold in 2017.

C. CONTRACTED ENERGY PURCHASES

1. Purchased Power Contracts

SDG&E's forecast of total costs for non-renewable power purchase contracts in 2017 is [redacted]. These costs cover capacity payments and variable generation costs for OMEC, Orange Grove, Wellhead El Cajon and other facilities with which SDG&E has smaller contracts.

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

The largest components in this category are capacity and generation costs for the OMEC unit, expected to be [redacted], and Resource Adequacy capacity costs, expected to be [redacted]. The Morgan Stanley contract is also included in this category and is expected to cost [redacted].

2. Renewable Energy Contracts

SDG&E's renewable energy contracts usually contain only an energy payment and no capacity payment. In 2017, SDG&E's renewable energy portfolio will include a cost for all the renewable power delivered based on contract prices and the renewable energy credits described in Section II under "Renewable Energy Contracts." All costs associated with these contracts are booked as ERRA expenses and are forecasted to be $710 million for 2017. Attachment D details the renewable projects by fuel type, their costs and forecasted energy deliveries.

Customers who opt into the Green Tariff Shared Renewables ("GTSR") program, which consists of both a Green Tariff ("GT") component and an Enhanced Community Renewables ("ECR") component, pay a subset of the renewable costs.[11] The estimated GT customer usage in 2017 is 39 GWh.[12] The estimated GT charges include the cost of local solar[13] of $92.56/megawatt hour ("MWh"), Grid Management Charges ("GMC") of $0.0007/kwh and Western Renewable Energy Generation Information System ("WREGIS") costs of $0.00001/kwh. The estimated total cost of GT in 2017 is $3.7 million. The estimated ECR

[11] 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.

[12] GT and ECR usage forecasts were developed using average consumption estimates for each customer class in conjunction with program enrollment targets.

[13] 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 (Interim GT Pool). 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.

customer usage in 2017 is 0 GWh as this component is dependent on resources which are not expected to come on line until 2018. Therefore, no costs are expected in 2017 for ECR.

3. Qualifying Facilities Contracts

SDG&E's QF contracts consist of dispatchable capacity or firm capacity PURPA contracts. These contracts include provisions for both energy and capacity payments. The energy payments for QFs that are under firm capacity PURPA contracts are forecasted using SDG&E's Short-Run Avoided Cost ("SRAC") formula.[14] For the dispatchable contracts, SDG&E pays fuel, variable O&M and capacity payments. Most of these contracts, whether PURPA or dispatchable, are considered CTC QF contracts,[15] and the ERRA expenses are based on delivered energy multiplied by the market price benchmark ("MPB"). Any costs, including capacity payments, greater than the market price benchmark are booked to the TCBA. For the purposes of ERRA accounting, ERRA expenses for CTC QF contracts are recorded on Line 5 of Attachment A, "Contract Costs (CTC up to market)," and are forecasted to be [redacted] in 2017. Attachment D details the breakdown of all the units discussed in this section and shows the associated costs, both ERRA and TCBA, and the forecasted energy deliveries. These costs include the indirect GHG cost embedded in the market price that flows through the SDG&E SRAC formula. I present GHG quantities and costs in Section IV of my testimony.

D. GENERATION FUEL

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

In 2017, the ERRA expense for generation fuel purchased by SDG&E for Palomar,

[14] The derivation of the SRAC price for QF contracts is posted monthly on an SDG&E website: http://www2.sdge.com/SRAC/.

[15] 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.

Miramar I & II, Desert Star and Cuyamaca is forecasted to be [redacted].[16] These forecasted expenses include in lieu gas fees for Palomar and Miramar I & II, which are also recovered in ERRA. These costs are calculated based on SDG&E's forecasted fuel usage for these plants and the applicable tariffs, Schedule GP-SUR[17] and Schedule EG[18].

E. LOCAL GENERATION

As previously noted, SDG&E has entered into contracts for generation resources which specifically provide local Resource Adequacy for the SDG&E system. Since these contract costs are allocated to both bundled and direct access customers, the costs are accounted for in a separate Local Generation Balancing Account. The Escondido Energy Center, Carlsbad Energy Center and Pio Pico contracts are included in this balancing account and are expected to cost [redacted], including direct GHG costs and net of supply ISO revenue. Attachment A details the breakdown of local generation expenses.

F. CAISO RELATED COSTS

SDG&E forecasts the miscellaneous CAISO costs to be [redacted] in 2017. SDG&E also forecasts the cost of the FERC Fees and Western Renewable Energy Generation Information System to be [redacted] in 2017.

G. HEDGING COSTS & FINANCIAL TRANSACTIONS

SDG&E's resource portfolio has substantial exposure to gas price volatility as a result of fuel requirements for its gas-fired resources, as well as the gas price-based pricing formula for its QF contracts. To manage this exposure, SDG&E engages in hedging activity, consistent with its

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[16] Capital and non-fuel operating costs for these plants are recovered through the Non-Fuel Generation Balancing Account ("NGBA") as required by D.05-08-005, Resolution E-3896 and D.07-11-046.
[17] Customer-procured Gas Franchise Fee Surcharge.
[18] Natural Gas Intrastate Transportation Service for Electric Generation Customers.

CPUC approved procurement plan,[19] and it will book the resulting hedging costs and any realized gains and losses from hedge transactions to ERRA consistent with its CPUC-approved hedge plan. The estimate of hedging costs for 2017 is [redacted], calculated as the marked-to-market profit/loss of hedges already in place, plus expected broker fees. The profit/loss of these and future hedges placed will rise and fall with market prices. Therefore, the final cost or savings will not be known until the settlement process has been completed for the hedge transactions.

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

Finally, I have included the Kern River Transportation Service Agreement ("TSA"), which is estimated to be [redacted] in 2017, as a financial transaction that is recoverable as an ERRA cost, as approved by the Commission in Decision 14-12-002.

H. CONVERGENCE BIDS

SDG&E uses convergence bids[20] to hedge certain operational risks in the day-to-day management of its portfolio. It is not possible to forecast the gains or losses associated with potential convergence bidding activity because of the unpredictable relationship between day-ahead and real-time prices. Therefore, SDG&E did not forecast an ERRA revenue/charge for

[19] SDG&E's 2012 Long Term Procurement Plan, Appendix B: Electric and Gas Hedging Strategy
[20] 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.

convergence bids.

I. CONGESTION REVENUE RIGHTS ("CRRs")

Market participants, including SDG&E, were allocated CRRs by the CAISO for which they can nominate source and sink P-nodes[21] to match those in their portfolio. If congestion arises between the source and sink P-nodes, the CAISO will pay the market participant holding the CRR the congestion charges to offset the congestion costs incurred. SDG&E expects its CRRs to generate revenues from the CAISO to offset congestion costs incurred within its portfolio. However, expected revenues were not forecast for the 2017 ERRA forecast because SDG&E assumed congestion-free clearing prices to develop forecasts for load requirement costs and generation revenues. A forecast of CRR revenues would have required SDG&E to forecast offsetting market-congestion prices at various P-nodes over the 2017 period. Since there are no forward market prices for congestion, we do not have a strong basis to perform this forecast without introducing complexity and additional uncertainty into the forecast.

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

J. INTER-SCHEDULING COORDINATOR TRADES ("IST")

In the CAISO market, SDG&E may transact ISTs[22] bilaterally with counterparties to hedge long or short positions. Under an IST purchase, SDG&E pays the counterparty the contracted energy price and in return receives payment from the CAISO based on the market

[21] 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.
[22] ISTs are financial bilateral transactions which allow SDG&E to hedge long or short price positions in the market.

clearing price. Under an IST sale, SDG&E receives payment from the counterparty based on the contracted energy price and in return pays the market clearing price to the CAISO. For IST purchases and sales, the payment to, or revenue from, the counterparty is largely offset by the respective credit from, or payment to, the CAISO. Because ISTs are used as a hedge against unknown market prices, SDG&E does not include a forecast of the net cost or benefit from these transactions.

IV. SONGS UNIT 1 OFFSITE SPENT FUEL STORAGE COSTS

A. Background

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

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

While the Commission has historically approved SDG&E's recovery of these costs, resulting from its 20% ownership interest in SONGS Unit 1 offsite spent fuel storage. in SDG&E's General Rate Case ("GRC") filings, SDG&E may now recover these costs through the ERRA forecast application process, per Decision 15-12-032.

B. 2017 Forecast

SDG&E estimates its 2017 SONGS Unit 1 offsite spent fuel storage expense to be $1.023 million (2017$), plus adjustments for escalation, in accordance with the GE-Hitachi spent fuel storage contract. The storage contract utilizes the Bureau of Labor Standards' labor non-financial corporations and industrial commodities indices to forecast escalation rates, which are included in SDG&E's billing statement. This estimate is based on a spent fuel storage cost forecast prepared by SCE's Nuclear Fuel Manager utilizing the contract escalation terms.

V. 2017 FORECAST OF GHG COSTS

In this section, I describe the cost forecast for GHG compliance obligations under the California Air Resources Board ("ARB") cap-and-trade program. The cap-and-trade program provides that compliance obligations in the electricity sector are applicable to "first deliverers of electricity."[23] Generally, first deliverers of electricity in 2017 are electricity generators inside California that emit more than 25,000 metric tons ("MT") of GHG, and importers of electricity from outside of California. The cap-and-trade program requires that first deliverers of electricity, except publicly-owned utilities and small generators (less than 25,000 MT of emissions), purchase all of the allowances and offsets needed to meet their compliance obligations.[24] SDG&E is the first deliverer for its utility-owned generation, for generation it

[23] ARB, Article 5: California Cap on Greenhouse Gas Emissions and Market-based Compliance Mechanisms, Section 95811(b).
[24] ARB, Article 5: California Cap on Greenhouse Gas Emissions and Market-based Compliance Mechanisms, Section 95851.

purchases under third-party tolling agreements in California, and for its imports of electricity into California. The cost of allowances and offsets is a direct GHG cost. In Section V.A below, I address direct GHG compliance costs associated with SDG&E utility-owned generation plants, procurement of electricity from third parties under tolling agreements, and electricity imports attributed to SDG&E.

SDG&E customers also face a second type of GHG compliance cost -- indirect costs. Indirect costs are costs embedded in market electricity prices, or costs that SDG&E incurs from third parties under contracts. The party selling the power is responsible for the GHG allowance acquisition, but it implicitly charges SDG&E for the cost of acquiring allowances. In Section V.B. below, I address indirect GHG costs. In Section V.C., I describe the calculation of both direct and indirect 2017 GHG costs. Finally, in Section V.D, I discuss the 2017 allowance auction revenues and the allocations of those revenues.

A. Direct GHG Emissions

Each first deliverer of electricity within California must surrender to ARB one allowance or offset for each MT of carbon dioxide emissions, or its equivalent (CO_2e). Under ARB's first deliverer approach, SDG&E will have a direct compliance obligation for GHG emissions from burning natural gas at facilities in its portfolio, including carbon dioxide, methane, and nitrous oxide. I forecasted SDG&E's expected direct GHG compliance costs using the same production simulation model results that produced the ERRA expenses discussed above. The amount of fuel needed for each natural gas fired plant is provided as an output based on the expected operation of the plant, including fuel associated with starts. The fuel volume is then multiplied by an emissions factor of 0.05307 MT of CO_2e per MMBtu to calculate direct emissions obligations for each plant.[25] The forecast of GHG emissions from SDG&E facilities in 2017 is included in Table 4 below.

Similarly, the estimated emissions for tolling agreements (*e.g.*, Otay Mesa) are estimated by multiplying the forecast of MMBtu of natural gas burned from the production simulation by the emission factor of 0.05307 MT of CO_2e per MMBtu. Table 4 below provides the forecast of GHG emissions from generators that are under tolling agreements with SDG&E in 2017.

In addition, SDG&E imports out-of-state electricity to a delivery point inside California, and it is thus responsible for the GHG emissions attributed to generation of that electricity. There are three categories of GHG emissions associated with imports. First, there are imports from "specified sources" (*i.e.*, imports where the source of the power is known), which consist of either a specific plant or an asset-controlling supplier. Accordingly, power from SDG&E's Desert Star combined-cycle generation plant in Nevada, for example, is included on the same basis as SDG&E's other utility-owned facilities—multiplying the forecast of MMBtu of natural gas burned from the production simulation by the emission factor of 0.05307 MT of CO_2e per MMBtu.[26] Second, imported power from "unspecified sources" is multiplied by an estimated transmission loss factor of 1.02[27] to estimate the MWh related to unspecified electricity imports. The quantity is multiplied by the ARB default emission rate, 0.428 metric tons of CO_2e per

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[25] 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 – CO2, CH4, and NO2. Table C-1 of 40 C.F.R. Section 98 provides an emissions rate for CO2 of 0.05302 MT/MMBtu. Table C-2 of 40 C.F.R. Section 9 gives a default emission factor for CH4 of 0.000001 MT/MMBtu. Using a Global Warming Potential of 21, the resulting CO2e emission rate is 0.00002 MT/MMBtu. The default NO2 emission rate is given as 0.0000001 MT/MMBtu, and the Global Warming Potential is 310, resulting in a CO2e emission rate of 0.00003 MT/MMBtu. Combining the 3 elements results in an overall emission rate of 0.05307 MT/MMBtu. SDG&E portfolio of GHG emitting resources use only natural gas, and not other fuels.

[26] 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.

[27] Transmission losses on SDG&E's system are measured at approximately 2% of load requirement.

MWh.

Third, electricity from out-of-state renewable resources that are not imported can be used to offset the emissions of imports under the ARB "Renewable Portfolio Standard ("RPS") adjustment." Specifically, the RPS adjustment is equal to the default emission rate multiplied by the MWh from the eligible renewable resources, as measured at the point of generation.[28] Currently, SDG&E's RPS adjustment is in dispute by ARB so a discount of 50% was applied to reflect the potential for a reduced RPS adjustment. Both the emissions of imported power and the offsetting RPS adjustment are shown in Table 4 below. Monthly emissions for all categories are summarized in Attachment E.

B. Indirect GHG Emissions

In addition to the direct GHG costs described above, the cap-and-trade program results in GHG compliance costs being embedded in the market price of electricity procured in the wholesale market and from third parties. The cost to purchase electricity from the wholesale market, as well as from suppliers under contracts that include market-based prices, will have these embedded costs of compliance with the cap-and-trade program built into the electricity price. The compliance instrument will be procured by the first deliverer, rather than by SDG&E, as purchaser. SDG&E's expected indirect GHG compliance costs are based on an assumption that all power sold by SDG&E-controlled assets are used by SDG&E customers, up to the level of the forecasted SDG&E load.[29] If the total CAISO market purchases exceed the MWh from SDG&E-controlled generation, then the assumption is that SDG&E entered into market

[28] ARB, Article 5: California Cap on Greenhouse Gas Emissions and Market-based Compliance Mechanisms, Section 95852(b)(4)(C).

[29] 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.

purchases to cover this difference. To estimate the GHG emissions embedded in these net CAISO market purchases, SDG&E used the ARB's default emissions rate, 0.428 MT per MWh.

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

Contractual GHG costs do not provide a good estimate of actual GHG costs. Determining actual GHG costs however, is difficult because it requires knowledge of confidential counterparty data and the choice of method used to split the GHG emissions between electricity production and useful thermal energy. For simplicity, SDG&E estimates GHG costs associated with CHP on the assumption that the CHP units, on average, are as efficient as unspecified power, assigning a 0.428 MT per MWh emissions rate to all purchases of power from CHP facilities. The GHG emissions from indirect sources are summarized on an annual basis in Table 4 and on a monthly basis in Appendix E.

Table 4: 2017 GHG Total Emissions Forecast		
Resource	**Fuel (000 MMBtu)**	**GHG (000 Metric Tons)**
Palomar- UOG	[redacted]	
Otay Mesa- PPA		
Desert Star- Out of State		
Goal Line- PPA		
Escondido Energy Center-PPA		
Pio Pico- PPA		
Carlsbad Energy Center- PPA		
Miramar- UOG		
Yuma- PPA Out of State		
Fuel-Based		
	Generation (GWh)	
Imports	[redacted]	
RPS Adjustment		
Total Direct Emissions		[redacted]
Resource	**Generation (GWh)**	
Net Market Purchases	[redacted]	
CHP		
Total Indirect Emissions		[redacted]
Total Forecasted Emissions		**4,287**
Conversions		
Natural Gas	0.0531	MTons/MMBtu
Market Purchases	0.428	MTons/MWh
Imports	0.428	MTons/MWh

C. 2017 GHG Costs

I calculated a proxy for the 2017 GHG emissions price as $13.58/MT. This figure was derived using a recent (March 1, 2016) assessment of 2017 GHG market prices based on the average of forward prices on the Intercontinental Exchange ("ICE") over the previous 22-day period, consistent with the period used for forecasting natural gas and electricity prices associated with the forecast of emissions in Table 4. The GHG cost forecast multiplies the expected emissions, both direct and indirect, by the forecasted proxy GHG price resulting in forecasted GHG costs for 2017 of $ 56,233,224 for ERRA and $1,983,921 for Local Generation.

D. 2017 Allowance Auction Revenues

The ARB allocates cap-and-trade allowances to SDG&E for 2017. SDG&E is required to place all of these allowances for sale in ARB's 2017 quarterly auctions. I developed the forecast of allowance revenues by multiplying the total number of allowances allocated to SDG&E for consignment by a forecast price for the allowances.[30]

Under ARB's regulations, the allowances available for allocation to electrical distribution utilities each budget year is currently 97.7 million MT multiplied by the cap adjustment factor (0.907(for 2017)), and SDG&E's share of electric sector allowances (7.2901% (for 2017)).[31] The total allowances that will be allocated to SDG&E for 2017 is expected to be 6,460,042 MT. The allowance price is the same proxy price as used in the calculation of GHG costs, $13.58/MT. The allowance auction revenue forecast is the allowances allocated times the allowance price or $87,727,369.

SDG&E currently has no approved incremental energy efficiency and clean energy investments in 2017, so the available funds for such projects are equal to 15 percent of the forecasted 2017 allowance auction revenue amount or $13,159,105.

AB 693 establishes the Multifamily Affordable Housing Solar Roofs Program ("Multifamily Program") to provide financial incentives for installation of solar energy systems on multifamily affordable housing properties, as specified in the statute. An ALJ ruling in the Development of a Successor to Net Energy Metering proceeding ordered that funding for the Multifamily Program be included in SDG&E's ERRA forecast application. These amounts have

[30] 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.
[31] ARB, Cap-and-Trade Regulation, Section 95891 at Tables 9-2 and 9-3.

not been explicitly approved in another proceeding, but have been ordered to be put on line 14 of Appendix D-1 by this ruling, as the most reasonable line of the template to account for the funding to be used for this new statutory program. For 2016, the funding amount is $630,910 which is 5% of the forecasted 2016 available funds for clean energy investments $12,618,203. For 2017, the funding amount is $1,315,911 which is 10% of the forecasted 2017 available funds for clean energy investments $13,159,105.

Additionally, industrial customers in energy intensive trade-exposed ("EITE") industries will receive an allocation from the allowance auction revenue. This group is defined in D.14-12-037 as those firms in North American Industry Classification System ("NAICS") codes counted as EITE by ARB, as listed in Table 8.1 of the cap-and-trade regulation.

SDG&E estimates the EITE set aside amount based on the total sales to customers in the NAICS codes of Table 8-1 of the ARB cap-and-trade regulation who are in the cap-and-trade program or signed an attestation confirming their eligibility.[32] The sales amount is appropriate for the approximation since the ARB assistance factor for 2017 is still 100 percent for all eligible entities.[33] Total sales for facilities with less than 10,000 metric tons are based on sales to customers who have facilities not fully covered by the small business credit. The total sales are multiplied by an estimate of the GHG intensity from D.14-12-037, and the GHG proxy price to calculate potential EITE revenue return for 2017. Specifically, SDG&E projects 2017 EITE customers' total usage of 174,403 MWh based on actual 2015 usage multiplied by the emissions factor associated with consumption, 0.379 MT/MWh, from D.14-12-037.[34] The dollar conversion factor of $13.58 is the proxy GHG price for 2017 described previously. The total 2017 EITE allocation is $897,621.

[32] Resolution E-4716
[33] D.14-12-037, Conclusion of Law 2, page 93.
[34] D.14-12-037, Finding of Fact 65, page 87.

VI. CONCLUSION

In conclusion, SDG&E requests that the Commission approve the forecasts I provide for use in developing the ERRA, TCBA, LG and SONGS Unit 1 Offsite Spent Fuel Storage Cost revenue requirements. SDG&E also requests that the Commission authorize recovery of the forecasted 2017 GHG costs, which are also used in determining the revenue requirement, and the volumetric revenue return for small business and residential customers. This concludes my direct testimony.

VII. QUALIFICATIONS

My name is Benjamin A. Montoya. My business address is 8330 Century Park Court, San Diego, California, 92123.

I have been employed as a Principal Resource Planner in the Resource Planning group of SDG&E since 2000. Prior to that, I was employed in positions of increasing responsibility in the following SDG&E departments: Gas Engineering, Gas Operations, Gas Control, and Gas System Planning. I also served as a project engineer on the Mexicali Pipeline Project with Sempra International for two years. I have been employed with SDG&E for 30 years.

I received a B.S. in Engineering from the United States Naval Academy and an M.B.A. from the University of San Diego. I am a licensed professional Mechanical Engineer in the state of California.

I have previously testified before the Commission on issues related to gas system planning, electric resource planning and in multiple ERRA proceedings.

Attachment A

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

ATTACHMENT A - SDG&E 2017 ERRA and LG EXPENSES

1	**EXPENSES ($)**	Jan	Feb	Mar	Apr	May	Jun	Jul	Aug	Sep	Oct	Nov	Dec	2017
2	ISO Load Charges (Energy & A/S Costs)	[redacted]												
3	ISO Supply Revenues													
4	Contract Costs (non-CTC)													
5	Contract Costs (CTC up to mkt)													
6	Generation Fuel													
7	CAISO Misc Costs													
8	Hedging Costs & Financial Transactions													
9	Contract Costs - CHP Costs (AB1613)													
10	Customer Incentives - SPP, DR,20/20													
11	Rewards/Penalties - Palomar Energy Ctr													
12	WREGIS Costs													
13	ISO CRRs Costs													
14	ISO Convergence Bidding Costs													
15	Rebalancing Costs (OMEC)													
16	Purchased Tradable Renewable Energy Credits (TRECs)													
17	Sales Tradable Renewable Energy Credits (TRECs)													
18	Net Surplus Compensation Costs (AB920)													
19	Authorized Disallowances													
20	Greenhouse Gas & Carrying Costs													
21	**Total Balancing Account Expenses**	[redacted]												**$ 1,279,455,276**
	Line 4 Contract Costs (non-CTC)													
	Otay Mesa Energy Center PPA payment	[redacted]												
	Otay Mesa Energy Center Energy Costs													
	Lake Hodges													
	Celerity													
	Kelco													
	El Cajon Energy Center Peaker Costs													
	Orange Grove Peaker Costs													
	NRG Capacity Costs													
	Calpeak Capacity Costs													
	Cabrillo 2 Capacity Costs													
	Other RA Capacity Costs (RA RFO, DRAM)													
	Morgan Stanley Index Costs													
	BP Energy Costs													
	Renewable Energy	$ 39,550,768	$ 46,289,126	$ 59,829,473	$ 65,276,671	$ 71,031,124	$ 67,580,109	$ 74,215,055	$ 74,116,800	$ 67,659,470	$ 62,486,359	$ 45,269,990	$ 37,047,953	$ 710,352,898
	Line 4 Total	[redacted]												
	Line 6 Generation Fuel													
	Palomar	[redacted]												
	Desert Star													
	Miramar													
	Miramar 2													
	Cuyamaca													
	Line 6 Total													
	In Lieu Gas Fee													
	Palomar													
	Miramar													
	Miramar 2													
	Total In Lieu Franchise Fee													
	Line 8 Hedging Costs & Financial Transactions													
	Hedging Costs													
	Kern River Transportation Service Agreement													
	Broker Fees													
	Line 8 Total													
	Market Purchases and Sales													
	Total Sales Revenue													
	Net Short													
	LG Expenses													
	Escondido Energy Center cost													
	Pio Pico cost													
	Carlsbad Energy Center cost													
	Local Generation Direct GHG cost													
	Local Generation Revenue													
	Total LG Expense													**$ 59,530,197**

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 2017 GENERATION PORTFOLIO DELIVERY VOLUMES (GWh)

	Jan	Feb	Mar	Apr	May	Jun	Jul	Aug	Sep	Oct	Nov	Dec	2017
CTC QF	[redacted]												
Non-CTC QF	[redacted]												
TOTAL QF	[redacted]												
Renewable - Bio Gas	14.9	12.9	12.8	12.7	13.1	12.0	16.3	15.9	15.9	12.9	12.6	12.8	164.6
Renewable - Other	-	-	-	-	-	-	0.6	0.7	0.6	0.0	-	-	1.9
Renewable - Solar	207.6	235.7	319.3	352.2	372.1	357.6	348.3	341.9	326.7	286.7	244.1	190.9	3,583.0
Renewable - Wind	116.5	153.6	186.9	212.2	253.3	232.4	174.8	149.6	120.6	129.9	132.6	106.9	1,969.3
Renewable - Wind REC	116.1	98.2	103.7	95.7	90.6	84.6	65.6	65.7	68.4	103.5	109.5	118.2	1,119.8
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	-
TOTAL NON-QF RENEWABLE	**455.0**	**500.4**	**622.7**	**672.8**	**729.0**	**686.6**	**605.7**	**573.7**	**532.2**	**533.1**	**498.8**	**428.7**	**6,838.7**
Miramar	[redacted]												
Miramar 2	[redacted]												
Cuyamaca	[redacted]												
Palomar	[redacted]												
Otay Mesa Energy Center	[redacted]												
Desert Star	[redacted]												
Celerity	[redacted]												
Kelco	[redacted]												
Lake Hodges	[redacted]												
BP	[redacted]												
Morgan Stanley	[redacted]												
El Cajon Energy Center	[redacted]												
Orange Grove	[redacted]												
Escondido Energy Center	[redacted]												
Pio Pico	[redacted]												
Carlsbad Energy Center	[redacted]												
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	-
TOTAL GENERATION	[redacted]												
Market Purchases	[redacted]												
TOTAL PORTFOLIO DELIVERIES	[redacted]												
Surplus Energy Sold	[redacted]												
LOAD REQUIREMENT (GWh)	[redacted]												

Note 1: Total Portfolio Deliveries do not include Wind REC

Note 2: Load Requirement is SDG&E bundled load including transmission losses

Attachment C

ATTACHMENT C - SDG&E 2017 RENEWABLE RESOURCE DETAIL

Power Purchase Deliveries (GWh)	Jan	Feb	Mar	Apr	May	Jun	Jul	Aug	Sep	Oct	Nov	Dec	2017
BIO GAS													
MM Prima Deshecha Energy LLC	3.2	2.8	3.2	3.0	3.3	2.8	3.7	3.5	3.5	3.1	3.2	3.1	38.3
MM San Diego LLC- Miramar Landfill	2.3	2.2	2.3	2.4	2.4	2.2	3.0	2.9	3.0	2.2	2.5	2.3	29.6
Otay Landfill 3	1.9	1.6	-	-	-	-	-	-	-	-	-	-	3.5
San Diego MWD	1.2	1.3	1.3	1.4	1.2	1.5	2.7	2.8	2.8	1.5	1.1	1.4	20.1
BIOGAS_FIT	6.2	5.1	6.1	6.0	6.2	5.4	7.0	6.7	6.7	6.1	5.8	6.1	73.2
Subtotal	**14.9**	**12.9**	**12.8**	**12.7**	**13.1**	**12.0**	**16.3**	**15.9**	**15.9**	**12.9**	**12.6**	**12.8**	**164.6**
OTHER													
SMALL_HYDRO_RAM	-	-	-	-	-	-	0.6	0.7	0.6	0.0	-	-	1.9
Subtotal	**-**	**-**	**-**	**-**	**-**	**-**	**0.6**	**0.7**	**0.6**	**0.0**	**-**	**-**	**1.9**
SOLAR													
NRG Borrego Solar	3.9	4.6	6.5	7.4	7.9	7.7	7.4	6.9	6.4	5.6	4.3	3.6	72.1
Sol Orchard	2.1	1.8	2.4	3.4	3.8	4.0	3.3	3.8	3.3	2.8	2.2	1.2	34.0
Solar Energy Project	1.1	1.1	1.5	1.6	1.7	1.6	1.6	1.6	1.4	1.4	1.2	1.1	16.8
SOLAR_PV_FIT	1.1	1.1	1.4	1.5	1.5	1.4	1.4	1.4	1.4	1.3	1.2	1.0	15.8
Arlington Valley Solar	21.1	23.7	32.6	36.5	39.0	40.2	37.1	33.9	32.0	26.8	21.6	18.2	362.7
Calipatria	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	25.4	26.7	33.5	34.5	35.8	33.7	33.8	33.9	33.1	30.6	27.9	23.3	372.3
Catalina_Solar	18.5	20.8	24.4	26.8	28.0	25.2	26.1	27.4	25.9	24.4	19.3	16.7	283.5
Centinela Solar1	17.9	22.4	30.7	37.8	40.1	39.5	38.4	35.2	34.0	29.3	24.2	17.6	367.1
Centinela Solar2	6.4	8.1	11.1	13.6	14.4	14.2	13.8	12.7	12.2	10.5	8.7	6.3	132.1
Desert Green	1.2	1.2	1.5	1.6	1.6	1.5	1.5	1.5	1.5	1.4	1.3	1.1	16.9
Imperial Valley Solar I	26.7	32.5	50.9	52.4	55.6	51.7	49.7	55.3	49.3	41.7	34.3	23.8	523.8
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
TallBear Seville	2.9	3.6	4.9	6.1	6.4	6.3	6.2	5.6	5.4	4.7	3.9	2.8	58.7
SolarGen 2	21.4	26.9	36.8	45.4	48.1	47.4	46.1	42.2	40.8	35.1	29.1	21.1	440.5
Cascade SunEdison	2.6	3.3	4.5	5.6	5.9	5.8	5.7	5.2	5.0	4.3	3.6	2.6	54.3
Csolar IV South	21.9	22.7	29.7	30.3	31.5	29.3	29.3	27.7	28.9	25.8	24.0	20.4	321.4
Csolar IV West	27.4	28.8	36.2	37.3	38.6	36.4	36.5	36.6	35.7	33.0	30.1	25.1	401.7
Subtotal	**207.6**	**235.7**	**319.3**	**352.2**	**372.1**	**357.6**	**348.3**	**341.9**	**326.7**	**286.7**	**244.1**	**190.9**	**3,583.0**
WIND													
Glacier Wind (TREC)	57.7	51.1	51.0	50.4	48.6	44.8	33.5	28.9	36.2	45.9	54.3	60.6	563.0
Rim Rock (TREC)	58.4	47.1	52.7	45.3	42.0	39.8	32.2	36.8	32.2	57.6	55.2	57.6	556.9
Kumeyaay	15.5	13.3	15.0	13.4	14.9	11.0	7.7	5.3	5.7	10.7	11.1	12.5	136.1
Coram Energy	1.1	1.2	2.1	2.5	3.1	3.0	2.6	1.9	1.7	1.8	1.4	1.4	23.7
Energia Sierra Juarez	43.8	37.8	42.1	37.9	41.4	32.2	19.0	13.0	14.0	30.4	32.1	36.0	379.5
Iberdrola Renewables	1.7	5.0	6.1	7.8	10.6	11.9	9.6	8.5	5.0	4.9	4.8	1.3	77.0
Manzana Wind	13.5	17.5	22.2	26.4	29.9	32.2	23.4	22.9	20.0	18.2	18.6	13.9	258.8
Oak Creek Wind Power	0.2	0.5	0.5	0.6	0.7	0.7	0.8	0.8	0.5	0.4	0.3	0.1	6.0
Oasis Power Partners	9.6	11.3	11.5	16.4	18.2	20.9	15.6	13.3	11.4	12.2	11.2	7.1	158.6
Ocotillo Express	13.5	37.6	51.7	67.3	87.3	73.6	64.6	52.7	36.6	27.2	31.3	19.1	562.5
Pacific Wind	15.9	25.9	30.2	33.2	39.7	39.4	24.3	24.1	21.0	19.8	18.9	13.9	306.3
San Gorgonio	1.0	1.5	3.0	4.0	4.5	4.5	3.5	3.2	2.8	2.5	1.4	0.9	32.9
WTE/FPL Acquisition	0.7	2.1	2.5	2.8	3.1	3.1	3.7	3.8	2.1	2.0	1.6	0.6	28.1
Subtotal	**232.5**	**251.8**	**290.6**	**307.9**	**343.9**	**317.1**	**240.5**	**215.3**	**189.0**	**233.5**	**242.1**	**225.1**	**3,089.1**
RPS SALES	-	-	-	-	-	-	-	-	-	-	-	-	-
Subtotal	**-**	**-**	**-**	**-**	**-**	**-**	**-**	**-**	**-**	**-**	**-**	**-**	**-**
Total Power Purchase Costs ($000)													
BIO GAS	$ 1,258	$ 1,092	$ 1,129	$ 1,125	$ 1,160	$ 1,058	$ 1,435	$ 1,392	$ 1,397	$ 1,140	$ 1,117	$ 1,131	14,434.4
OTHER	$ -	$ -	$ -	$ -	$ -	$ -	$ 46	$ 58	$ 45	$ 1	$ -	$ -	149.7
SOLAR	$ 23,532	$ 27,394	$ 37,403	$ 40,882	$ 42,825	$ 41,900	$ 54,263	$ 56,427	$ 52,643	$ 45,707	$ 28,035	$ 21,818	472,829.5
WIND	$ 10,729	$ 14,433	$ 17,683	$ 19,996	$ 23,965	$ 21,734	$ 16,207	$ 13,889	$ 11,239	$ 11,939	$ 12,311	$ 10,028	184,152.9
WIND (REC)	$ 4,032	$ 3,370	$ 3,614	$ 3,273	$ 3,081	$ 2,888	$ 2,265	$ 2,351	$ 2,336	$ 3,700	$ 3,807	$ 4,070	38,786.4
RPS SALES	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -	-
Subtotal	**$ 39,551**	**$ 46,289**	**$ 59,829**	**$ 65,277**	**$ 71,031**	**$ 67,580**	**$ 74,215**	**$ 74,117**	**$ 67,659**	**$ 62,486**	**$ 45,270**	**$ 37,048**	**710,352.9**

Attachment D

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

ATTACHMENT D - SDG&E 2017 CTC QUALIFYING FACILITY (QF) DETAIL

CTC QF - Dispatchable (GWh)	Jan	Feb	Mar	Apr	May	Jun	Jul	Aug	Sep	Oct	Nov	Dec	2017
Goal Line QF	[redacted]												
Yuma Cogen Associates QF													
CTC QF - SRAC Priced (GWh)													
Naval Station QF	[redacted]												
North Island QF													
Navy Training Center QF													
Navy Training Center QF - Steam Turbine													
Aggregation of Hydro Units (SO1)													
Subtotal													
ERRA Expenses ($000)													
CTC QF													
(to Line 5 of Attachment A)													
TCBA Expenses ($000)													
CTC QF	[redacted]												$ 22,389.4

Attachment E

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

ATTACHMENT E - SDG&E GREENHOUSE GAS (GHG) DETAIL

2017 Direct Emissions (MT)	JAN	FEB	MAR	APR	MAY	JUN	JUL	AUG	SEP	OCT	NOV	DEC	2017
California UOG Plants	[redacted]												
California Tolling Generators													
Specified Imports													
Unspecified Imports													
RPS Adjustment													
Total Direct Emissions													
2017 Indirect Emissions (MT)													
Market Purchases													
CHP													
Total Indirect Emissions													
2017 Total Forecasted Emissions													**4,286,977**

BEFORE THE PUBLIC UTILITIES
COMMISSION OF THE STATE OF CALIFORNIA

DECLARATION
OF BENJAMIN A. MONTOYA

A.16-04-___
Application of San Diego Gas & Electric Company (U 902-E)
for Approval of Its 2017 Electric Procurement Revenue Requirement Forecasts and GHG-Related Forecasts

I, Benjamin A. Montoya, declare as follows:

1. I am a Principal Resource Planner for San Diego Gas & Electric Company ("SDG&E"). I included my Prepared Direct Testimony ("Testimony") in support of SDG&E's April 15, 2016 Application for Approval of its 2017 Electric Procurement Revenue Requirement Forecasts and GHG-Related Forecasts ("Application"). Additionally, as a Principal 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.[1] 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
BAM-3 lines 8-9	V.C	LSE Total Energy Forecast – Bundled Customer; confidential for the front three years
BAM-4 Table 1	IV.F	Forecast of Post-1/1/2003 Bilateral Contracts; confidential for three years
BAM-4 line 16, footnote 2	VI.A	Utility Bundled Net Open Position for Capacity; confidential for the front three years
BAM-5 Table 2	IV.A	Forecast of IOU Generation Resources; confidential for three years
BAM-6 line 5	V.H	Net capacity and energy forecasts by retail provider; confidential for the front three years
BAM-7 line 14	IV.B	Forecast of Qualifying Facility Generation; confidential for three years
BAM-8 lines 7-8	IV.J	Forecast of Wholesale Market Purchases; confidential for the front three years
BAM-9 line 11	II.A.2, V.C	Utility Electric Price Forecasts; confidential for three years, LSE Total Energy Forecast, confidential for the front three years
BAM-9 line 17	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
BAM-9 line 21 BAM 10, lines 2-4 BAM-12 line 11	II.B.4	Generation Cost Forecast of Non-QF Bilateral Contracts; confidential for three years
BAM-11 line 13	II.B.3	Generation Cost Forecast of QF Contracts; confidential for three years

[1] 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.

Confidential Information	Matrix Reference	Reason for Confidentiality and Timing
BAM-12 line 1	II.B.1	Generation Cost Forecasts of Utility Retained Generation, confidential for three years
BAM-12 lines 14 and 16	II.A.2	Utility Electric Price Forecasts; confidential for three years
BAM-13 lines 3 and 13 BAM-21 Table 4	I.A.4	Long-term Fuel (gas) Buying and Hedging; confidential for three years
BAM-21 Table 4 Application Attachment G, Template D-2: Forecasted Emissions and Costs; and Template D-5: Forecasted Emissions Intensity		GHG emissions forecast: Providing these 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.
Attachment A - SDG&E 2017 ERRA and LG Expenses	XI	Monthly Procurement Costs; confidential for three years
Attachment B - SDG&E 2017 Generation Portfolio Delivery Volumes • Cuyamaca, Palomar, Desert Star, and Miramar data • QF data • Otay Mesa, Celerity, Kelco, Lake Hodges, Wellhead, and Orange Grove data • Market Purchase data • Surplus Energy Sold data 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**
Attachment D - SDG&E 2017 CTC Qualifying Facility (QF) Detail		
• QF data	IV.E	Forecast of Pre-1/1/2003 Bilateral Contracts; confidential for three years
• Long-Term Power Purchase CTC data	IV.B	Forecast of Qualifying Facility Generation; confidential for three years
• CTC QF & Non CTC QF data	II.B.4	Generation Cost Forecast of Non-QF Bilateral Contracts; confidential for three years
•	II.B.3	Generation Cost Forecast of QF Contracts; confidential for three years
• TCBA Expenses data	II.B.3 and	Generation Cost Forecast of QF Contracts; confidential for three years
	II.B.4	Generation Cost Forecast of Non-QF Bilateral Contracts; confidential for three years
Attachment E - SDG&E Greenhouse Gas (GHG) Detail		GHG emissions forecasts: Providing these 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.

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 15th day of April, 2016, at San Diego, California.

Benjamin A. Montoya
Principal Resource Planner
San Diego Gas & Electric Company