Application No.: A.17-06-___
Exhibit No.: ____________
Witness: Joseph Pasquito
Date: June 1, 2017

SAN DIEGO GAS & ELECTRIC COMPANY

PREPARED DIRECT TESTIMONY OF

JOSEPH PASQUITO

****REDACTED, PUBLIC VERSION****

BEFORE THE PUBLIC UTILITIES COMMISSION
OF THE STATE OF CALIFORNIA

June 1, 2017

TABLE OF CONTENTS

PREPARED DIRECT TESTIMONY OF

JOSEPH PASQUITO

ON BEHALF OF SDG&E

I. INTRODUCTION

This testimony presents San Diego Gas & Electric Company's ("SDG&E") compliance with least-cost dispatch ("LCD") requirements during the record period of January 1 through December 31, 2016, as specified by applicable California Public Utilities Commission ("Commission") decisions. LCD pertains to the day-ahead and intra-day dispatch and trading of SDG&E's portfolio of resources, including utility-owned generation ("UOG") and power purchase agreements ("PPA"). The following summarizes Commission decisions on LCD and how SDG&E implemented these decisions in a manner consistent with its Commission-approved Long-Term Procurement Plan ("LTPP").[1]

Standard of Conduct 4 (SOC4) was adopted by the Commission in Decision ("D.") 02-10-062 and further discussed in D.02-12-069, D.02-12-074, D.03-06-076, and D.05-01-054. The decisions established standards of conduct by which an IOU must administer its portfolio, specifically SOC 4, which states that "[t]he utilities shall prudently administer all contracts and generation resources and dispatch the energy in a least-cost manner."[2]

During 2016, SDG&E filed four quarterly advice letters ("AL") covering the record period as required in D.02-10-062. AL 2892-E for Q1 2016 was approved on March 2, 2017 and is effective June 1, 2016; AL 2935-E for Q2 2016 was approved on March 2, 2017 and

---

[1] For purposes of the Commission's review and the compliance findings requested herein, the relevant LTPP is SDG&E's 2014 LTPP, approved in Commission Resolution E-4543, in compliance with D. 15-10-031.

[2] D.02-10-062 at 52 and Conclusion of Law ("COL") 11 at 74.

effective August 31, 2016; AL 2991-E for Q3 2016 is pending approval; and AL 3039-E for Q4 2016 is pending approval. These advice letters provide detailed information on transactions that SDG&E executed while following its LCD process, as well as other data (e.g., customer load, resource schedules and fuel transactions) pertinent to the LCD process during the record period. SDG&E's Quarterly Compliance Reports ("QCRs") for 2016 were in compliance with SDG&E's Commission-approved LTPP and applicable procurement-related rulings and decisions.

SDG&E testimony and attachments will demonstrate compliance with LCD based on Decision ("D.") 15-05-005 ("the Decision"). Based on the Decision, SDG&E's testimony will include the following:

- Overview/narrative of LCD in the California Independent System Operator ("CAISO") markets.
- Description of SDG&E's bidding and scheduling processes.
- Summary of reports/tables documenting aggregated annual exceptions for:
    - Incremental cost bid calculations
    - Self-commitment decisions
    - Master File data changes
- Narratives reviewing significant strategy changes, internal software and/or process changes and CAISO market design changes during the Record Period.
- A background summary table outlining baseline annual data, including:
    - Total capacity of the dispatchable (bid in) portfolio;
    - Total dispatchable capacity lost due to planned or forced outages;
    - Total capacity of non-dispatchable (exclusively self-scheduled) portfolio;
    - Total non-dispatchable capacity lost due to planned or forced outages.

- Total Energy awards (dispatchable and non-dispatchable by resource type and broken down by self-scheduled versus market awards);

- Demand Response ("DR") metrics will be provided for dispatchable DR programs with economic triggers including the following:
  - Annual Summary of results reporting requirement related to dispatch of DR resources including when all programs were dispatched and an explanation of when DR resources could have been dispatched but were not.
  - Calculation of the number of hours when the utility forecasts that trigger criteria will be reached, as a percentage of hours in which the trigger conditions were reached in the same period.
  - Total energy actually dispatched as a proportion of maximum available energy for each DR program broken down monthly and annually.
  - Explanation as to why a DR resource was not dispatched due to its maximum availability.
  - Cost impact on overall resource dispatch of not calling DR programs up to their maximum available amounts when program was forecasted to be triggered.
  - Consideration of whether the selection of the DR events called minimized overall portfolio cost of dispatching supply resources.
  - Explanation of SDG&E's opportunity cost methodology and demonstration of its application during the Record Year.

II. SDG&E PORTFOLIO OVERVIEW

For the record period, most of SDG&E's energy requirements were met with SDG&E PPAs and UOGs. SDG&E's PPAs included qualifying facility ("QF") contracts and contracts for renewable energy, dispatchable generation and out-of-state resources, all of which are described in the Direct Testimony of SDG&E witness Daniel L. Sullivan. SDG&E's UOG assessment included combined-cycle ("CC") plants and combustion turbines ("CT") generators.

The tables below provide summary data for resources in SDG&E's portfolio. The must-take resources in Table 1 are non-dispatchable; SDG&E has an obligation to accept the generation that is produced from these resources without regard to variable cost and therefore are exempt from SDG&E's LCD process described in this testimony. The total of their generation in part determines SDG&E's net long or short position, which did factor into LCD. The resources in Table 2 are dispatchable and were therefore the focus of SDG&E's least-cost process during the record period. The "Capacity" column in Tables 1 and 2 are derived from CAISO Master File Resource Data Template ("RDT") maximum capacities for resources where SDG&E is the scheduling coordinator ("SC") and contract capacities for resources where SDG&E is not the SC.

Table 1a: Must-Take Resources

Resource	Contract MW	Dispatch Profile	Ancillary Service Capability
QF contracts (Natural Gas)	138	Baseload As-Available	None
QF Renewable	2	Intermittent As-Available	None
Renewable non-intermittent resources	30.2	Baseload (as available)	None
Renewable Intermittent Resources	2146 (maximum)	Intermittent	None

Table 1b: Dispatchable Resources

Resource*	Capacity MW	Dispatch Profile	Ancillary Service Capability
Palomar CCGT Natural Gas SP15	575	Load Following	Spinning Reserve Regulation
Otay Mesa CCGT Natural Gas SP15	603.68	Load Following	Spinning Reserve Regulation
Cuyamaca CT Natural Gas SP15	45.42	Peaker	Non-Spinning Reserve
Miramar 1 CT Natural Gas SP15	48	Peaker	Non-Spinning Reserve
Miramar 2 CT Natural Gas SP15	47.9	Peaker	Non-Spinning Reserve
YCA CT Natural Gas NGila	55	Peaker	None
Orange Grove CT Natural Gas SP15	96	Peaker	Non-Spinning Reserve
El Cajon Energy Center CT Natural Gas	47.4	Peaker	Non-Spinning Reserve

Resource*	Capacity MW	Dispatch Profile	Ancillary Service Capability
SP15			
Escondido Energy Center CT (Wellhead) Natural Gas SP15	48.71	Peaker	Non-Spinning Reserve
Desert Star CCGT Natural Gas SP15	494.58	Load Following	Spinning Reserve
Goal Line CT Natural Gas SP15	49.9	Peaker	None
Lake Hodges Unit 1 Hydro SP15	20	Pumped Storage	None
Lake Hodges Unit 2 Hydro SP15	20	Pumped Storage	None

*CCGT= Combined Cycle Gas Turbine; CT= Combustion

III. OVERVIEW OF LEAST-COST DISPATCH IN CAISO MARKETS

On April 1, 2009, following Federal Energy Regulatory Commission ("FERC") approval of its market redesign application, the CAISO implemented the Market Redesign Technology Upgrade ("MRTU"), which introduced fundamental changes in the way resources are committed and dispatched. The most significant of these changes was the implementation of a centralized energy market which requires load-serving entities ("LSEs") to procure energy and ancillary services ("A/S"), and generators to sell energy and A/S, through the CAISO markets based on self-schedules and economic bids.

Prior to MRTU, load-serving entities assessed the costs of their supply options, including market energy, and submitted schedules to the CAISO balancing those supplies with their load or sales obligations. MRTU established a centralized spot market that enables all resources, through standardized bidding and scheduling rules, to be competitively dispatched based on variable costs to serve total system load, subject to operational and transmission constraints. These resources are no longer matched up to any particular LSE's load; LSEs now meet their needs by self-scheduling or bidding for energy in the CAISO market. However, LSEs may still rely on bilaterally procured resources to hedge the day-to-day cost of buying energy and A/S from the CAISO markets, to the extent these contracted resources pass on the revenues for energy and A/S awards received from those same CAISO markets back to the LSE.

SDG&E periodically revises and improves its LCD processes to meet new MRTU-related CAISO tariff rules and operating requirements while maintaining compliance with SOC 4, particularly with regard to self-schedules, convergence bids and economic bids for its dispatchable resources. These self-schedules and bids for dispatchable units must accurately reflect variable costs to enable the CAISO market to produce energy and A/S awards for SDG&E's resources that are consistent with LCD. SDG&E utilizes a cross-validation procedure for bids to ensure the accuracy of its resource bids with respect to cost and the accuracy of its self-schedules in the CAISO market.

The CAISO market solves for the least-cost unit commitment and dispatch solution incorporating self-schedules and economic bids from generators and load which takes into account various resource operational constraints, resource and transmission outages, impact of convergence bids, inter-temporal constraints and the effect of adjacent balancing authorities impacted by the CAISO system. It is important to note that CAISO is solving for the lowest system cost, not the highest revenue for a resource; therefore, looking at a resource's awards in isolation may not yield expected results. If a resource is awarded in a manner below their costs for a given 24-hour period, the resource may qualify for bid cost recovery ("BCR"). The nodal

("Pnode") market prices explicitly account for the economic effects of re-dispatching resources to relieve congestion constraints.

The CAISO optimizes the dispatch of the several hundred generators across its system to find the overall lowest-cost mix of resources to meet CAISO system load requirements (including those of SDG&E). The CAISO market also co-optimizes the allocation of dispatchable capacity between generation and A/S capacity, based on prices submitted for each of these services in the resource bids.[3] The resulting allocation of awards between generation and A/S across the system therefore reflects the economic tradeoff between capacity used for generation and what is reserved for A/S.

The CAISO employs an iterative mixed-integer programming methodology to account for the numerous constraints cited above. Appendix 1 of this testimony is the technical bulletin published by the CAISO that describes in greater detail its LCD optimization processes with respect to the IFM (Integrated Forward Market). Specifically, Section 2.3 states:

> The SCUC [Security Constrained Unit Commitment] engine determines optimally the commitment status and the Schedules of Generating Units as well as Participating Loads and Resource-Specific System Resources.
>
> ***The objective is to minimize the Start-Up and Minimum Load costs and bid in Energy costs and Ancillary Services, subject to network as well as resource related constraints over the entire Time Horizon*****,** e.g., the Trading Day in the IFM. The time interval of the optimization is one hour in the DAM and 5 or 15 minutes in the RTM depending on the application.
>
> In IFM the overall production (or Bid) cost is determined by the total of the Start-Up and Minimum Load Cost of CAISO-committed Generating Units, the Energy Bids of all scheduled Generating Units, and the Ancillary Service Bids of resources selected to provide Ancillary Services. ***This objective leads to a least-cost multi-product co-optimization methodology that maximizes economic efficiency, relieves network Congestion and considers physical constraints***. The economic efficiency of the market operation can be achieved through a

[3] For example, if a generator's energy bid price is $10/MWh in-the-money relative to the clearing price, then the IFM may award the generator an A/S award only if it the A/S clearing price exceeds $10 or the generator's bid, whichever is greater.

> least cost resource commitment and scheduling with co-optimization of Energy and Ancillary Services.[4]

A feature of the CAISO market is the ability for market participants to submit self-schedules rather than economic (or price) bids for load and generation. A self-schedule is a price-taker bid that is awarded regardless of the Pnode clearing price (even if negative) subject to operational constraints. SDG&E submits a self-schedule for its forecasted load in the Day Ahead Market ("DAM"). SDG&E also submits self-schedules for its (non-intermittent resources) must-take resources in the DAM.[5] This approach is needed because SDG&E has an obligation to receive energy from these resources, regardless of the market price, and self-scheduling in the DAM ensures that revenues paid to these resources effectively offset costs charged to SDG&E load.

Self-schedules may otherwise not support the least-cost objective. Most importantly, they are price-taker bids that provide no assurance (unlike price bids) that market revenues will pay for fuel and other operating costs, and thereby expose SDG&E ratepayers to unnecessary risk of losses. Furthermore, self-schedules undermine the CAISO's ability to procure A/S and thereby drive up the costs (which are charged to load) for these products that are necessary for grid reliability.

Consequently, SDG&E primarily submits cost-based price bids for its dispatchable generation rather than self-schedules. Under CAISO market rules, cost-based bids provide SDG&E ratepayers a means to recover variable costs associated with start-up, minimum load and dispatch from the market. Moreover, price bids enable the CAISO to perform its co-optimization between energy and A/S awards.

[4] CAISO Technical Bulletin: Market Optimization Details, November 19, 2009 at 2-8 – 2-9 (emphasis added). Available at: http://www.caiso.com/Documents/TechnicalBulletin-MarketOptimizationDetails.pdf.

[5] For brevity, this testimony does not distinguish between SDG&E or the resource owner performing the Scheduling Coordinator functions for SDG&E's resources.

Finally, with respect to LCD, price bids allow for CAISO market results to meet the least-cost dispatch solution across the entire system, including SDG&E's service territory, because the CAISO selects the mix of resources with the lowest total variable cost (as represented by their price bids) to meet load requirements. To the extent SDG&E submits cost-based price bids reflecting variable costs per D.02-09-053, and most accurately represents operational parameters and constraints to the CAISO, the results produced by the CAISO markets for SDG&E's supply portfolio are consistent with the Commission's LCD requirements.

IV. LEAST-COST DISPATCH SCHEDULING AND BIDDING PROCESS

SDG&E's LCD process is managed by SDG&E's Electric and Fuel Procurement department ("E&FP"). Key personnel involved in daily LCD activity in the 2016 compliance period included fuel traders and schedulers, power traders, day ahead (pre)schedulers and real-time schedulers and analysts. The LCD process consisted of a number of parallel functions, which are described in this section.

A. Pre-Day-Ahead Planning

During the compliance period, LCD forecasts for a particular delivery date began with a weekly production cost model that optimized resources to serve SDG&E's load requirement for the following 12-day period. The model software (GenTrader)[6] was set up with numerous parameters, including load forecast, plant operating data, resource availability, forecasted Locational Marginal Pricing ("LMP") prices for all relevant pricing points and dispatch constraints which allowed the model to perform complex analysis to produce a preliminary forecast of generation dispatch and market transactions that minimized total variable cost to serve the forecasted load requirement. The GenTrader model produced expected utilization of resources for the planning horizon, including dispatch levels, fuel requirements and market transactions. A detailed description of the inputs to GenTrader which SDG&E used for determining an LCD forecast is as follows:

a. <u>Load forecasts</u>: SDG&E produced load forecasts using a load forecasting model developed by Pattern Recognition Technologies, Inc. ("PRT"). The PRT model utilized technologies such as artificial neural networks nonlinear, statistical data modeling tools where the complex relationships between inputs and outputs were modeled or patterns were found,[7] and special proprietary algorithms analyzed relationships between historical system load and weather data to develop the load forecast for SDG&E's system. SDG&E's load forecast for bundled customers was determined by adjusting SDG&E's system load for transmission losses, which were calculated as a percentage estimate of the forecasted system load based on historical data, less the load forecast for Direct Access customers.

---

[6] SDG&E uses GenTrader, a production cost and optimization software application produced by Power Costs Inc. ("PCI"). GenTrader employs an optimization algorithm to calculate the optimal, constraints-bound mix of market transactions and generation from SDG&E's resource portfolio over the study period. SDG&E acquired GenTrader as part of a PCI product suite in preparation for the new Market. PCI introduced GenTrader in 1999 and continues to implement modeling and technology enhancements that SDG&E receives under its license agreement. GenTrader is used by other clients across the country in nodal and traditional markets to optimize generation portfolios. Additional product description is available at http://www.powercosts.com/solutions-products/gentrader/.

[7] As defined by www.techopedia.com.

Direct Access load forecast was provided by SDG&E's Electric Load Analysis group based on the historic load for current Direct Access accounts in the SDG&E billing system. These load forecasts were produced weekly as inputs to the Gen Trader 12-day LCD forecast.

b. Master File Updates and Operating constraints: The Gen Trader model also required a variety of cost inputs for each dispatchable resource to properly determine its dispatch cost. The Master Files included a subset of data accessible by the resource's scheduling coordinator ("SC"), which is referred to as the Resource Data Template ("RDT"). SDG&E periodically submitted master file changes via an RDT update process that was validated by CAISO. Such data included but was not limited to heat rates, ramp rates and variable operation and maintenance costs ("VOM"), minimum and maximum operating points, fuel delivery charges and start-up and minimum load costs. In addition, numerous operating constraints/parameters, included in the RDT, were also fed into the model including start-up time, minimum shutdown and run times, multi-stage generation ("MSG") transitions and ramp rates. The GenTrader model optimized the dispatch of each resource given its generation cost and operating constraints.

c. Forecast of resource availability: A significant portion of SDG&E's resource portfolio was comprised of must-take resources (QF and renewable energy), as listed in Section II. SDG&E received weekly, and in some cases daily, forecasts of hourly deliveries from the resource operator. In addition, SDG&E generated availability forecasts for some smaller contracts based on historical performance. If the unit availabilities varied from the full operating capability, they were communicated to the CAISO via the Scheduling and Logging for ISO of

California ("SLIC") application as required. On February 26, 2015, CAISO changed from the SLIC application to Outage Management System ("OMS") to update unit derates and outages.

d. Market prices: The GenTrader LCD forecast model required a forecast of fuel prices for each of the dispatchable resources in SDG&E's portfolio, and a forecast of hourly power prices for various market delivery points where SDG&E generation units were located. Fuel prices were based on forward natural gas price curves at SoCal Border and Kern Delivered (derived from the New York Mercantile Exchange ("NYMEX"), Intercontinental Exchange ("ICE") and broker quotes) and tariff or contract gas transportation costs. Power prices were based on forward power price curves for block power (derived from ICE and broker quotes) and shaped for each hour using price weighting factors derived from historical price and load profiles.

e. Miscellaneous: Other factors that affected GenTrader results included an hourly price weighting profile, Short-Run Avoided Costs ("SRAC") prices for QF economic curtailments and contract or regulatory limits that imposed additional constraints on economic dispatch. Use-limited resources including the Lake Hodges pumped-storage project and demand response products were not modeled by GenTrader due to unique constraints and were therefore optimized on a day-ahead/weekly basis based on market conditions, price forecasts and operating parameters.

GenTrader was then used to calculate the hourly dispatch level of dispatchable resource over the modeled period that was economic, or "in-the-money," relative to forecasted LMP prices. This determination considered up-front commitment costs (start-up and minimum load costs), incremental dispatch costs which varied by output level, and various operational constraints mostly consistent with resource data template ("RDT") data used by the CAISO in its market processes. For must-take resources, generation was assumed to equal their forecasted availabilities. If the sum of must-take and in-the-money dispatchable generation was less than that hour's load requirement, the short position, or Residual Net Short ("RNS"), was considered to be met with market purchases. If the sum of must-take and in-the-money generation was greater than that hour's load requirement, the long position was considered to be surplus generation available for economic market sales.

B. Day-Ahead Planning

On a day-ahead basis by approximately 6:00 a.m., preschedulers updated the PCI software with updated values, specifically the load forecast, market prices and resource availabilities. Other resource operational data such as heat rates are relatively static between the 12-day plan and day-ahead plan and were not typically updated. Key distinctions between the 12-day and day-ahead model parameters were as follows:

a. <u>Load forecast</u>: SDG&E used updated temperature and humidity forecasts from SDG&E's weather forecasting service to re-run its PRT load forecasting model. In addition, pre-schedulers applied manual adjustments to the PRT result when warranted to offset known limitations to the model. For example, because PRT forecasts were based on historical data, PRT made adjustments to reflect sudden changes to the weather forecast such as the onset of a heat wave. The prescheduler also benchmarked the PRT forecast to that published by the CAISO for SDG&E's service area (when available) to identify and resolve significant deviations.

b. Resource availabilities: SDG&E received updated and more accurate availability information for its resources on a day-ahead basis. These updates captured information that may not have been included in the 12-day model, such as ambient derates, forced derates and outages. These updates were also submitted to the CAISO via OMS as required.

c. Market prices: Spot natural gas and power trade actively in the day-ahead market. SDG&E uses a forecasting tool it developed using Microsoft Excel to forecast load and resource prices for the Day-Ahead Market (DAM). DA Price forecasts are generated by applying historical price spreads and hourly shapes to the SP15 prices traded in the DA market to create a 24-hour price forecast. SDG&E has provided a record of SDG&E's accuracy with respect to forecasted LMP (SP15 Trading Hub and SDG&E's DLAP) for 2016 and a comparison of forecast accuracy from the previous year in Attachment A - *2016 Summary Load Data and LMP price forecasts.xls*). LMPs are entered into PCI to reflect updated market conditions to run the optimization model.

After updating the GenTrader model with these inputs, SDG&E then re-optimized the mix of market transactions and resource dispatches. As with the 12-day plan, GenTrader produced a plan for unit commitments, dispatch levels and economic purchases and sales. These results helped inform gas and power trading requirements and the potential for self-scheduling of dispatchable resources.

C. Day-Ahead Trading and Scheduling

The CAISO runs the Day-Ahead Market ("DAM") to economically clear load and resources that were scheduled or bid in. The DAM required SDG&E to submit separate schedules and bids for each resource and load. Results of the DAM became financially binding at the market clearing price for each resource and load that was awarded, and the sum of SDG&E's awarded resources did not necessarily balance with SDG&E's load award. The process to self-schedule and bid in SDG&E's load and resources is discussed below.

- Load: During the record period, SDG&E sought to self-schedule 100% of the day-ahead bundled load forecast. Self-scheduling ensured that SDG&E would purchase its forecasted load requirement in the DAM rather than rolling the requirement into the real-time market which produces more volatile prices. The DAM was preferred for two other reasons. The first reason was that SDG&E was required to self-schedule or bid in its (non-use limited) resources into the DAM under Resource Adequacy must-offer rules in the CAISO Tariff. Therefore, while balanced schedules were not mandated, the DAM did provide a means for supply revenues to effectively offset the load costs provided that SDG&E self-scheduled its load in the DAM. The second reason was that the depth of the day-ahead bilateral market allowed SDG&E to hedge its self-scheduled load exposed to the CAISO DAM clearing price via bilateral fixed-price transactions. Attachment A - *2016 Summary Load Data and LMP price forecasts.xls* contains detailed summary load data and results.
- Non-intermittent must-take resources: SDG&E continued to self-schedule available must-take generation on a day-ahead basis to offset DAM load awards. For resources that were scheduled by sellers and not SDG&E, sellers continued to self-schedule their available generation into the DAM. Credit for the Day Ahead ("DA") revenues was transferred back to SDG&E either via an Inter-SC Trade ("IST") for the self-scheduled quantity, or settled after the fact by the settlements group.

- Generation convergence bids: Some of SDG&E's intermittent resources that were part of the Participating Intermittent Resource Program ("PIRP") were scheduled in the hour-ahead scheduling process as required by the CAISO. SDG&E utilized convergence bids to effectively shift the CAISO's payment for the PIRP resources from the real-time market to the DAM, thereby providing a better offset to load charges which, as discussed above, settle against DAM prices. The Commission authorized this application of Convergence Bidding in D.10-12-034. The daily process consists of three main steps: (1) retrieval of the day-ahead PIRP forecast for the relevant resources; (2) creation of convergence bid quantities considering a) the percentage of the day-ahead PIRP quantity forecast to be shifted into the DAM, b) convergence bid quantity limitations imposed by the CAISO and c) reduction of quantities in hours that have historically produced negative returns on the convergence bids SDG&E would have submitted; and (3) pricing of convergence bids such that the virtual supply was not sold at unreasonably low price levels. The results of SDG&E's convergence bidding activity were reported quarterly to the Procurement Review Group ("PRG") as required by D.10-12-034.
- Dispatchable resources: SDG&E's objective, with respect to self-schedules and price bids for dispatchable resources, was to maintain adherence to LCD principles. This objective was primarily met by bidding generation into the DAM at cost–based prices consistent with the LCD modeling.
- Generator price bids: Energy bids consist of three basic components - startup cost, minimum load cost and incremental energy bids. Startup and minimum load costs which can be declared as registered or proxy were used in the CAISO DAM.

In addition, bidding rules required that incremental energy bids be monotonically increasing over the range of output. This rule at times conflicted with the actual incremental energy cost of combined cycle plants because the true incremental cost decreases as well as increases as they transition through operating modes to ramp from minimum to maximum load. Therefore, SDG&E had to develop modified energy bid curves or employed MSG modeling for its combined cycle fleet (Palomar, Desert Star, and Otay Mesa) to comply with the monotonically increasing bid rule and to incorporate transition constraints and costs between configurations. Other components of the price bid that pertained to A/S-certified units are bids for Regulation, Spinning Reserve and Non-Spinning Reserve. As discussed in Section V, the DAM algorithm co-optimized dispatchable capacity between generation and A/S awards; and the generator was paid an amount greater than or equal to its opportunity cost of forgoing a profitable day-ahead energy sale. However, co-optimization did not consider lost energy sales in the real-time market. Therefore, SDG&E incorporated an estimate of expected real-time energy market net revenues that the A/S capacity could otherwise derive from that market.

- Lake Hodges Pumped-Storage Unit: As noted in the LCD modeling discussion, SDG&E performed a separate optimization analysis of Lake Hodges due to its unique operational characteristics. For example, its fuel cost was based on the cost of power required to pump water into the upper reservoir such that the generator could generate power at a later time. Secondly, it was only economic to operate the plant (from a LCD perspective) when the cost of pumping water into the upper reservoir was recovered by revenues from using that water for generation. Given that these unique features presented significant modeling challenges that only applied to 40 MW of generation capacity, SDG&E chose to develop an in-house spreadsheet tool to determine the optimized dispatch of this resource rather than devoting resources to upgrade its GenTrader application (although such a solution may be pursued in the future). The spreadsheet tool produced a self-schedule for the unit for both pump and generation modes through the following steps: (1) retrieval of an hourly power price forecast over the following week; (2) determination of economically rational pump and generation hours based on the power price forecast, pump efficiency parameters, variable O&M costs and load uplift charges; and (3) modification of the hours from step 2 based on operational constraints such as water usage restrictions. Trading or scheduling personnel manually reviewed the results, modified as needed to ensure all other operational constraints were respected, and uploaded the final pump and generation self-schedules or bids into SDG&E's scheduling application for submittal into the CAISO market.

SDG&E has provided Attachment B, entitled "2016 Hydro and Pump Storage," which includes summary reporting on bidding and dispatch of dispatchable hydro and pumped storage resources.

- Power Trades: During the 2016 compliance period, SDG&E primarily traded day-ahead financial power to hedge the risk of unknown DAM clearing prices, and their effect on the magnitude of market awards on SDG&E's resources. Financial power was traded in lieu of physical power due to greater market liquidity, but provided the same hedge. Like physical power purchases, SDG&E purchased financial power to lock in energy prices below its marginal generation cost, or sold financial power to lock in sales of surplus generation above variable cost. The volume of energy purchased or sold was informed by the results of the GenTrader LCD model and a position analysis spreadsheet developed in-house; both tools calculated SDG&E's hourly short or long position based on similar inputs and provided a more robust result of hedging needs than a single model. SDG&E traded these products on the ICE or through voice brokers to ensure competitive prices, and submitted these trades for Commission review in its QCR.

D. Hour-Ahead Scheduling and Real-Time Dispatch

The CAISO operated the Hour-Ahead Scheduling Process ("HASP") market that performed several important functions related to LCD. Like the DAM, the HASP market established financially binding awards for awarded hour-ahead self-schedules and bids, but only at intertie scheduling points. In addition, the HASP market enabled SDG&E to submit updated self-schedules and cost-based bids for its dispatchable resources so the CAISO could issue incremental or decremental dispatches in the real-time market based on this updated data. SDG&E also self-scheduled its PIRP certified intermittent resources in HASP as required under PIRP rules. Of note, the CAISO did not allow load self-schedules and bids to be updated in HASP; any differences between actual load and the load quantity cleared in the DAM was automatically settled at the real-time market price.

The CAISO issued incremental and decremental awards an hour before delivery for intertie bids and in real-time (5 to 15 minutes ahead) for online or fast-start internal generation through its Automated Dispatch System ("ADS"). Decremental energy awards essentially caused resources to buy back the day-ahead award if the HASP or real-time price fell below the bid price submitted in HASP; incremental awards caused resources to sell additional energy or A/S relative to the day-ahead award. SDG&E's resources responded directly to these ADS instructions. If a resource experienced an unplanned outage or other change in operational capability, these updates were submitted to the CAISO via OMS as required to notify the CAISO of the status and preclude infeasible real-time dispatch instructions.

Because HASP and real-time prices are historically more volatile than and can deviate significantly from the day-ahead price, the impact of the real-time market on SDG&E's LCD results varied day-to-day. This impact could be particularly negative if real-time market prices spiked when SDG&E's portfolio was significantly short. The short position could arise for several reasons, including:

- SDG&E generally self-scheduled 100% of its forecasted load in the DAM; if actual load exceeded the forecast, the result was a short real-time position;
- resources (must-take and dispatchable) that were awarded in the DAM carried a delivery obligation in the real-time market for the awarded quantity; thus, an outage or curtailment to any of these resources that prevented it from meeting its day-ahead obligation resulted in a short real-time position;
- awarded convergence bids in the DAM triggered a buyback in the real-time market; if this buyback was not fully covered by physical generation, the convergence bid resulted in a short real-time position; and
- if real-time prices were lower than day-ahead, the CAISO could dispatch resources below their day-ahead award, as described earlier in this section; these decremental dispatches would result in a short real-time position (albeit a desirable one should real-time prices continue to remain low).

If real-time prices spiked under any one or more of these scenarios, SDG&E's dispatchable resources may not have been able to ramp quickly enough to fully eliminate the short position. The combination of real-time price spikes and short portfolio position was and continues to be a constant risk to ratepayers, depending on the severity of each.

In order to mitigate the risk of a short real-time position, SDG&E from time to time submitted HASP self-schedules on its dispatchable resources. For a resource already committed in the DAM (e.g., combined cycle or steam unit), the self-schedule prevented the CAISO from decrementing the resource below a certain level in the real-time market such that a short position could be avoided. For a resource that was not awarded in the DAM with a short startup time (e.g., peakers), the self-schedule ensured that the CAISO dispatched this resource in real-time to offset an existing short position.

Since the implementation of MRTU, SDG&E has observed a reduction in the market's interest (and consequently liquidity) to trade real-time power. SDG&E predominately relied on the CAISO real-time market to clear residual real-time positions, and used self-schedules as described above to manage its real-time short position.

E. Award Retrieval and Validation

SDG&E implemented post-MRTU procedures to retrieve CAISO day-ahead awards and communicate them to its resources. While dispatchable generators in fact respond to CAISO ADS or regulation dispatch in real time, they required timely notice of day-ahead awards in order to adequately prepare to meet startup, shutdown and MSG transition requirements. Furthermore, advance notification of regulation awards ensured that generators would be prepared to operate in Automated Generation Control ("AGC") in order to follow regulation dispatch. Lastly, the day-ahead notification allowed enough time to address any inconsistencies between a generator's day-ahead award and its stated operational constraints previously communicated to the CAISO through OMS.

SDG&E performed a post-market assessment to review market results and validate that the CAISO process resulted in LCD of SDG&E's portfolio. The assessment is referred to as the Bid Evaluator report, provided through the PCI software package. Bid Evaluator compared SDG&E's expected day-ahead awards for its dispatchable generation based on published market prices with actual DAM results. Generally, the market results aligned closely with Bid Evaluator results (subject to operational constraints), confirming that LCD of SDG&E's portfolio was achieved.

Although SDG&E investigated substantive deviations between CAISO market solutions and Bid Evaluator optimization, any deviations did not necessarily indicate an incorrect dispatch or need for further action. Upon citing a deviation, SDG&E could modify inputs or bidding strategy, initiate a change proposal to PCI for development, or notify CAISO of deviations to determine the cause which may be recognized as a market flaw through Customer Inquiry Dispute and Information ("CIDI") tickets.

V. CONSTRAINTS TO LEAST-COST DISPATCH

As stated in the discussion of LCD principles, SDG&E performed its LCD activities within limits established by numerous types of constraints that range from operational, regulatory and contractual to risk mitigation and market conditions. An after-the-fact review of a particular day's dispatch may show a deviation from LCD because of the effects of such constraints.

Some constraints were operating limits inherent to the resources in the portfolio. For example, generators cannot continually cycle back and forth between online and offline because of minimum run time and shutdown time of each combustion turbine. Therefore, the lowest cost unit may not have been dispatched if sufficient time for startup was not available. Or, surplus energy could be sold below variable generation cost if SDG&E was long on energy and had no resources that could be cycled off. Some other common examples of LCD constraints include, but are not limited to, the following:

- Exceptional Dispatch ("ED") is a form of dispatch the CAISO relies on to meet reliability requirements that cannot be resolved through market processes. The CAISO orders EDs to address local generation requirements, system capacity needs, transmission outages, software limitations and other operational issues. Because EDs are reliability-driven, they are outside the scope of LCD and likely to be uneconomic relative to market prices or other resources. All CAISO resources are obligated to comply with these dispatches.
- Residual Unit Commitment ("RUC") is a market award for capacity the CAISO issues to ensure that sufficient capacity is committed to meet system load. Although RUC resulted from the market process, it is required to manage grid reliability and is outside the scope of LCD. SDG&E resources were obligated to be available to provide the RUC capacity if awarded, which required that they could be committed uneconomically relative to other resources.
- Unit testing and maintenance, such as Relative Accuracy Test Audit ("RATA") tests and heat treats, require generators to run at pre-defined load points to achieve an objective. During these periods, generation is considered must-take and cannot be dispatched according to LCD economics.
- Constrained pipeline operations may impact LCD. A generator may be constrained in its ability to provide real-time dispatch because of limited gas balancing rights on a pipeline. Another example of pipeline constraints was Operational Flow Orders ("OFOs") declared by Southern California Gas Company ("SoCalGas"). Under a high-inventory OFO, if a resource failed to

consume 90% of the scheduled natural gas quantity, the pipeline assessed penalties. Therefore, resources were constrained from following real-time LCD economics to decrease generation.

- Use-limited resources are resources that are only available for a limited number of hours per period. To efficiently allocate dispatches on these units, SDG&E planned their use over a monthly or annual time horizon depending on the limit. For example, annual environmental restrictions limit the number of startups on certain combustion turbines. Other resources that were use-limited include Demand Response programs that can be triggered for limited hours each month.
- CAISO market solutions look at a 24-hour time horizons and to come up with the most economic "system" solution, individual resources may need to be awarded uneconomically. Therefore, LCD is achieved on a system basis as opposed to an individual unit by hour basis.

VI. SUMMARY REPORTS AND TABLES

In this Section, SDG&E provides additional detailed information that support SDG&E's execution of the LCD process during 2016, as described in Section IV. The following provides a description of information provided as well as tables which summarize annual exceptions for incremental cost bid calculations, self-commitment decisions and Master File data changes:

1. Incremental Cost Bid - Incremental bids submitted to the CAISO are calculated using the heat rate, fuel costs, fuel transportation fees, GHG costs, and variable operations and maintenance costs and any other costs used in the calculation. For the record period, the annual and monthly tables below provide a listing of all variances between calculated and submitted bids that are greater than $0.10 and the related cost impacts. In addition, the table provides any occurrences where

dispatchable resources were not bid into the CAISO markets when available. Attachment C – 2016 *Incremental Bid Cost Calculations.xslx* provides details of incremental bids submitted to the CAISO and any potential exceptions. Potential reasons for LMP clearing higher than incremental bid costs include but are not limited to the consideration of start-up and minimum load costs, MIP (Mixed Integer Processing) gap, inter-temporal constraints, transmission constraints, conditions used as initial conditions for next day and the effect of adjacent balancing authorities' areas.

Table 2 below summarizes the potential impact of the bid exceptions.

Table 2

Summary of 2016 Incremental Bid Cost Exceptions

Month	No. of Variances (2B)	% of Bids Submitted	Cost Impact (2C)
Jan	0	0.00%	$0.00
Feb	0	0.00%	$0.00
Mar	24	0.15%	$0.00
Apr	0	0.00%	$0.00
May	0	0.00%	$0.00
Jun	0	0.00%	$0.00
Jul	0	0.00%	$0.00
Aug	0	0.00%	$0.00
Sep	0	0.00%	$0.00
Oct	0	0.00%	$0.00
Nov	0	0.00%	$0.00
Dec	0	0.00%	$0.00
Total	**24**	**0.01%**	**$0.00**

2. Self-Commitment – The summary tables below contain the costs of self-schedule decisions for dispatchable thermal resources during the record period. Also contained are details including total energy self-scheduled, and supporting data of daily forecasts of schedules if bid or self-scheduled, forecast revenues and bid costs if bid or self-scheduled, and decisions to self-schedule or bid. Attachment D - *2016 Self Schedules Supporting Data 1.xlsx* and Attachment E - *2016 Self*

Schedules Supporting Data 2.xlsx contain the details of self-commitment costs and the reasons to self-schedule. Table 3-a and 3-b below summarize cost impacts of self-scheduling.

There was one instance of an inadvertent self-schedule for one hour on December 14, 2016 with Desert Star Energy Center. This event had no cost impact, as demonstrated in Attachment D. The error occurred when SDG&E intended to put in initial conditions for real-time market HE24 of the current day but inadvertently submitted a self-schedule for next day. The initial condition submission for real time HE24 is routinely used to give CAISO the option to keep a unit online if the current day ahead award for HE24 is zero.

This event is unrelated to the prior year's self-scheduling event where energy was self-scheduled instead of ancillary services. The cross-validation process at the time did not include the review of initial conditions submissions and therefore were not part of the cross-validation process. SDG&E has since improved the bid and self-scheduling validation procedure to help identify an inadvertent schedule before they are submitted.

For these reasons, despite this event, SDG&E nonetheless demonstrated LCD compliance for Record Year 2016.

Table 3-a
Summary of 2016 Self Schedules

Month	1) Self Schedule Awards (in MWh)	2) Market Awards (Above Self Schedule) (in MWh)	3) Self Schedule Costs	4) Self Schedule Revenues	5) Revenue - Costs Above Self Schedule 4) - 3)	6) Bid Cost Above Self Schedule	7) Revenues Above Self Schedule	8) Revenue - Costs Above Self Schedule 7) - 6)
January	[redacted]							
February								
March								
April								
May								
June								
July								
August								
Septembe								
October								
November								
December								
2016 Total								

Note: Assumes $0 costs for potential hot start.

Table 3-b
Summary of 2016 Hypothetical Non-Self Schedules

Month	1) Estimated Market Awards if resource was solely bid into Day Ahead Market (in MWh)	2) Estimated Revenues if resource was solely bid into Day Ahead Market (no self schedules)	3) Estimated Costs if resource was solely bid into Day Ahead Market (no self schedules)
January	[redacted]		
February			
March			
April			
May			
June			
July			
August			
September			
October			
November			
December			
2016 Total			

Note: Assumes $0 costs for potential hot start.

3. Master File Data Changes – During the record period, SDG&E periodically changed Master File submissions to reflect Proxy or Registered Start-Up or Minimum Load costs for its dispatchable resources. Table 3, the annual table below, summarizes the number of times and the reasons for selecting proxy or registered costs. In addition, the tables provide the frequency of calculations that differed from values submitted to the CAISO, and the cost impacts, by month. Attachment F – 2016 *Master File (RDT) Change Exceptions.xlsx* provides the

details of changes made during the record period. Table 4 below summarizes proxy and registered cost change exceptions.

Table 4 Summary of 2016 PROXY and Registered Cost Change Exceptions				
Category	**Proxy Elections**	**Registered Elections**	**Incorrect Submissions**	**Error Rate**
Startup	13	18	0	0%
Minload	15	15	0	0%
Totals	**28**	**33**	**0**	**0%**

VII. MARKET DESIGN AND PROCESS CHANGES

The following is a summary of certain CAISO market design changes that have affected SDG&E's business processes during 2016:

1. Capacity Procurement Mechanism Replacement- CAISO replaced its administratively determined backstop procurement mechanism with a market based procurement mechanism. The market mechanism allows suppliers to offer excess capacity on an annual, monthly and intra-monthly timeframe. The market mechanism incents suppliers to offer their capacity to compete for backstop procurement. Load serving entities benefit from the market mechanism because of price competition rather than an administratively determined price. As a supplier, SDG&E has the opportunity to offer in the market mechanism.
2. Reliability Services Initiative Phase 1a– CAISO enhanced its availability incentive and non-availability penalties in the new Resource Adequacy Availability Incentive Mechanism ("RAAIM") starting in Nov 2016. The new RAAIM changes account for flexible capacity non-availability. Non-availability is calculated based on how the capacity are bid/offered into the CAISO energy markets rather than just focusing on forced outages for such resources. In order to reduce the non-availability penalties,

suppliers can provide substitute capacity from other resources. Flexible capacity substitution is new for 2017.

VIII. ANNUAL TABLE

1. The following table summarizes, by resource type, the total capacity bid or self-scheduled into the market as well as capacity lost due to planned or forced outages. The table also includes total energy awards for each resource broken down by self-schedules versus market awards. Attachment G - *2016 Annual Summary.xlsm* provides the details of dispatchable and non-dispatchable resources. Table 5 is an annual summary of dispatchable and non-dispatchable resources including capacity available and unavailable, self-schedules and DAM awards.

Table 5
Background Summary- 2016 Annual Summary

Dispatchable	Resource Type	Capacity (PMAX in MWh)	Unavailable Capacity (MWh)	DA SS Awards (MWh)	Award due to Market	Total Awards
Dispatchable	Natural Gas Generation	18,071,235	2,291,597	199,632	6,528,056	6,727,688
Dispatchable	Pump Hydro	352,678	29,571	10,402	(23,429)	(13,026)

Non-Dispatchable	Resource Type	Capacity (PMAX in MWh)	Unavailable Capacity (MWh)	DA SS Awards (MWh)	Award due to Market	Total Awards
Non-Dispatchable	BioGas	223,114	5,748	167,391	1,098	168,489
Non-Dispatchable	Conduit Hydro	46,116	25,006	-	8,562	8,562
Non-Dispatchable	Digester Gas	42,427	1,537	19,217	60	19,277
Non-Dispatchable	Gas Turbine	25,614	78	-	62	62
Non-Dispatchable	Natural Gas Generation	1,288,613	158,343	649,327	7,160	656,487
Non-Dispatchable	Other	455,714	33,178	199,789	50	199,839
Non-Dispatchable	Solar	11,497,683	282,950	-	2,890,094	2,890,094
Non-Dispatchable	Wind	3,752,525	300,991	-	716,006	716,006
Total		**35,755,718**	**3,128,997**	**1,245,758**	**10,127,722**	**11,373,479**

IX. FUEL PROCUREMENT

During the record period, SDG&E supplied fuel to all natural gas-fired, dispatchable resources in the portfolio. SDG&E performed as the pipeline-registered Fuel Manager and Fuel Supplier for most of its dispatchable resources. These included SDG&E-owned or -contracted resources (Miramar, Cuyamaca, Palomar, Desert Star, OMEC, Orange Grove, Escondido Energy Center, El Cajon Energy Center and Goal Line). The fuel costs for these SDG&E resources are charged to SDG&E's Energy Resource Recovery Account ("ERRA").

As discussed in the Commission-approved LTPP, SDG&E's procurement process is to secure approximately 90% of forecasted fuel volumes required to serve SDG&E's load forecast (but not economic sales) as firm monthly baseload supply. The advantages of baseload supply are that it (1) shields ratepayers from potentially volatile day-ahead natural gas prices; (2) is scheduled by market participants as a higher priority delivery than day-ahead supply; and (3) reduces the day-to-day trading and scheduling requirements, thereby reducing overall operational requirements. While the cost of baseload supply may be lower or higher than the spot price on any given day, over time these price differentials average toward zero, leaving SDG&E with the benefits cited above.

While most fuel supply was procured as firm monthly baseload, at all times during the Record Year, SDG&E used prevailing day-ahead or intra-day market prices to price out day-ahead or intra-day generation costs, which is consistent with LCD. For example, if the portfolio was short fuel relative to day-ahead requirements, fuels traders purchased incremental supply at the DAM price. Or, if the portfolio was long on fuel relative to real-time requirements, fuels traders sold the surplus baseload supply at the same-day market price. This coordination between fuel and power trading enabled SDG&E to accurately price variable generation costs so that the benefits of market transactions could be properly evaluated. Both baseload and daily natural gas trades for the record period were executed at competitive prevailing market prices and in compliance with the LTPP. The delivery points for the natural gas deals booked to ERRA were the various SoCal Border delivery points or the SoCalGas Citygate trading hub, since all dispatchable natural gas-fired resources in the portfolio (except Desert Star) use natural gas supplied at these points. Natural gas for Desert Star was procured at Kern receipt and delivery points. All SDG&E natural gas transactions for 2016 were reported and are reviewed by the Commission in SDG&E's QCR under the advice letters cited in Section I, above.

SDG&E also entered into financial transactions to hedge fuel costs during the record period. Hedge transactions consisted primarily of futures and basis swap purchases which together fixed the forward price of the monthly Natural Gas Intelligence ("NGI") SoCal Border index. Futures trades were executed through NYMEX. Basis swaps were executed over-the-counter ("OTC") directly with counterparties or through voice brokers and typically cleared through ICE Clear, a widely-used clearinghouse for OTC trades. These hedge transactions complied with the LTPP and internal quarterly hedge plans and were submitted for Commission review in SDG&E's QCR. However, hedge transactions are not considered in evaluating variable operating costs in the day-ahead or real-time markets and therefore do not affect the LCD process.

Throughout the record period, SDG&E held Backbone Transportation Service ("BTS") to transport natural gas from the various SoCal Border trading points to the SoCalGas Citygate. SDG&E purchased the BTS capacity from SoCalGas pipeline to increase the priority of fuel delivery to its dispatchable resources. The decision to purchase BTS is determined by several factors including: the price spread between the SoCal Border point and the SoCal Citygate, the quantity of Firm Interstate capacity SDG&E has purchased that can feed into that specific SoCal point BTS represent fixed costs and therefore are not considered in the LCD process.

Natural gas trading and scheduling processes remained largely intact through MRTU implementation. However, the DAM process increased the uncertainty of gas quantities to be traded in the DAM. Day-ahead generation awards are not known until about 1:00 p.m., well after next-day natural gas finished trading. Because of the time lag, fuels traders had to rely on generation award forecasts and judgment to establish their next-day fuel position. When actual results deviated from forecasted fuel quantities, fuels traders primarily relied on gas balancing services offered on SoCalGas' system and, to a lesser extent, on the Kern and Southwest Gas pipelines, or its storage capacity on SoCalGas' system. Occasionally, SDG&E traded and/or scheduled gas supplies in later pipeline scheduling cycles to avoid potential imbalance penalties. Activity in these later scheduling cycles was avoided to the extent lower availability of competitive bids and offers caused incremental transactions to cost more to SDG&E.

X. DEMAND RESPONSE

SDG&E has been developing and offering a selection of DR programs to its customers since 2001. The scope of these programs has changed as the concept of DR has evolved and has become an integral part of resource planning and energy management. DR programs have design objectives (reliability, economic, emergency, etc.) as well as specific tariffs or guidelines which describe set trigger conditions such as heat rate, system load, temperature forecast and/or emergency conditions. When triggers are met, SDG&E has discretion to dispatch a program, which allows SDG&E to assure event hours are available for times of greater need.

During the record year of 2016, SDG&E utilized its DR programs primarily to reduce electricity consumption during peak demand or to respond to system reliability needs. SDG&E's portfolio consists of programs that have economic triggers as well as programs with all non-economic triggers. Pursuant to D.15-05-005, as discussed above,[8] SDG&E's Capacity Bidding Program ("CBP"), a demand response program, is subject to the LCD standard as it has economic triggers and is bid into the CAISO market. In the remainder of this section, SDG&E provides information pertaining to the CBP program in SDG&E's DR portfolio and explains how the program was utilized in 2016. SDG&E has included its most recent wholesale market

[8] *See* p. JP-2.

integration progress report describing SDG&E's progress in integrating its Demand Response programs into the wholesale market.[9]

Capacity Bidding Program ("CBP")

CBP is an optional Demand Response program available to all commercial and industrial customers in the SDG&E's territory. CBP is operational from May 1st to October 31st each year. Program operation hours are Monday through Friday, excluding holidays, from 11 A.M. to 7 P.M. Participants receive a monthly capacity payment in exchange for reducing their load when requested by the utility. Participating customers who are also receiving bundled services from SDG&E receive an additional energy payment during CBP events.

CBP participating customers can choose to participate in one of two CBP products: (1) CBP Day-Ahead, and (2) CBP Day-Of. The distinction between the product types is the pre-event notification timing. Under the Day-Ahead product, customers are notified by no later than 3 P.M. the day prior to the actual event. The Day-Of product, provides event notification by 9 A.M the day of the event.

The CBP is capped at 44 event hours per month. The program triggers are:

- SDG&E may call an event when SDG&E's DLAP or when applicable, an established PNode price, divided by the Daily index price of SoCal Citygate reaches a resource dispatch equivalence of 19,000 Btu/kWh heat rate[10]; or
- SDG&E may call an event if SDG&E system conditions warrant; or
- At the request of CAISO (though still SDG&E's discretion to deploy).

Although the CBP tariff outlines program triggers, SDG&E is not required to dispatch the CBP program every time the economic trigger is reached. Therefore, SDG&E takes forecasted

[9] *See* Attachment L – 2016 Demand Response Market Integration Progress Report.doc.
[10] SDG&E switched from a heat range of 15,000 Btu/kwh to 19,000 Btu/kwh on June 16,2016 as approved on June 24, 2016 in Advice Letter 2858-E.

system demand, program limitations, and customer fatigue into account before making a final decision about dispatching the program.

SDG&E incorporates a bid strategy to select the highest heat rate (for four consecutive hours) occurrences in a particular month. Each day, SDG&E forecasted the applicable PNode's LMP for every remaining program operation hour (between 11am and 7pm) of the month. With this forecast, the National Gas Intelligence ("NGI") monthly index of the Socal Citygate gas price or the balance of the month price was applied to produce an hourly heat rate forecast. SDG&E then calculated the eleventh highest market heat rate (for a consecutive four-hour period) for the balance of operation hours of each month. If the eleventh highest forecasted heat rate was above 19, SDG&E used that value to formulate a bid price. If the eleventh highest forecasted heat rate was below 19, SDG&E used a 19 heat rate to formulate a bid price. The bid price was calculated by taking the higher of a 19 heat rate and the eleventh highest forecasted heat rate and multiplying that value times the SoCal Citygate price for the next day. After the PDR is dispatched the first time, SDG&E then would take the tenth highest forecasted heat rate of the remaining days of the month and so on until the eleventh dispatch. Bid prices may vary daily depending on revised, daily forecasted heat rates and/or the number of times PDR was dispatched.

The CBP was activated on sixty-six (21) occasions during the 2016 event season. Fourteen (14) events were Day-Ahead and seven (7) were Day-Of events. In all cases when CBP events were initiated during the record year of 2016, the quantified economic triggers from the tariff were met, and SDG&E determined that the system needs warrant such actions.

SDG&E started market integration for CBP in October of 2014 and continued to do so for the 2016 season. The market integration was limited to CBP bundled participants. SDG&E plans to continue bidding the CBP portfolio into the CAISO markets in 2017.

SDG&E also plans to integrate the Direct Access participants; however, there are no guarantees that SDG&E can receive Load-Serving Entity ("LSE") approval for successful bidding of the resource. Regardless, SDG&E will dispatch the entire program when the trigger is met.

Demand Response Metrics

In D.14-05-025, the Commission approved various reporting requirements proposed its Office of Ratepayer Advocates ("ORA"). The following discussion outlines those requirements as well as the manner in which SDG&E responded to them for Record Year 2016.

1. An annual summary of the results of the reporting requirement (related to dispatch of DR resources) adopted in D.14-05-025. At a minimum, the utilities should provide a summary of:
    a. The times and duration that all programs were dispatched;
    b. All cases where the DR program's trigger conditions were forecast to be met, and all cases where these trigger conditions were met;
    c. A list of occurrences when DR resources should have been dispatched but were not (i.e. a DR resource's economic trigger conditions were forecast by a utility but it was not dispatched). Each occurrence should be accompanied by an explanation detailing the reason for non-dispatch;
2. In addition to the Reporting Requirement in D.14-05-025, a calculation should be provided of the number of hours when the utility forecasts that trigger criteria will be reached, as a percentage of hours in which trigger conditions were reached in the same time period (monthly and annual basis).
3. The total energy dispatched as a proportion of maximum available energy for each DR program under scope of the proceeding (monthly and annual breakdowns).

This comparison should be provided in both percentage and nominal (MWh) terms. An example of the format is provided below:

a. In 2016 record year- utility A's CBP program dispatched 100MWh. This is compared to a total maximum available dispatch of 200 MWh for that program.

b. Therefore, utility A's CBP program did not dispatch 100 MWh of its total maximum available energy.

c. In 2016 record Year, utility A dispatched 50% of the available energy in the CBP program.

4. For each event the full capacity was not dispatched, an explanation should be provided as to why the DR resource was not dispatched to its maximum availability during the record period.

5. If the metrics in 3) above show that available energy was not dispatched for a program, provide an estimate the net cost impact on overall resource dispatch of not utilizing maximum available amounts when the program triggers have been forecasted to be reached. This metric should focus on the net cost of dispatching metric (3)(b). An example is provided below:

6. Metrics should be provided by the utility to identify whether the selection of DR events called minimized the utility's overall portfolio costs of dispatching supply resources. This assessment should include the average hourly net cost impact by program.

a. For events dispatched in the record year.

b. For all time periods when DR program triggers were forecasted by the utility (whether dispatched or not).

c. Comparison of a) and b) in both percentages and nominal (MWH) terms.

7. An explanation of how opportunity cost analyses were used to make the decision to call or not call an event. This should include an explanation of the opportunity cost methodology and demonstration of its application.

SDG&E has reviewed the preceding requirements, and in the following, discusses how the metrics SDG&E supplied in attachments comply with the Decision.

1. Attachment H - *ERRA 2016 Demand Response Metric 1.xslx* provides CBP summary results of when program was dispatched, when trigger conditions were forecasted and/or met, a list of occurrences when CBP was not dispatched but hit triggers as well as the reason for non-dispatch.

2. In the 2016 compliance period, SDG&E used the DAM clearing prices as the forecast trigger criteria for CBP Day-Ahead because the deadline to call the event is after the Day-Ahead final schedules are published. In regards to CBP Day-Of, SDG&E used the published DAM clearing prices and other real-time market conditions to determine if the CBP Day-Of should have been dispatched but did not forecast price triggers. As a result, the hours when the utility forecasts the trigger will be the same as the number of hours when the trigger conditions were met and no further data was provided.

3. Attachment I - *ERRA 2016 Demand Response Metric 2.xslx* provides CBP summary results of total energy dispatched as a proportion of the maximum available energy for CBP Day-Ahead and Day-Of. The comparison provides the metric in percentage and nominal (MWh) terms.

4. *Attachment H - ERRA 2016 Demand Response Metric 1* provides an explanation when CBP was not dispatched but hit triggers. CBP Day-Ahead

and Day-of was dispatched to full capacity each time SDG&E triggered an event.

5. Attachment J - *ERRA 2016 Demand Response Metric 5.xslx* provides a net cost impact of CBP Day-Ahead and Day-Of when triggers were met and resource was not dispatched to its maximum available capacity.

6. *Attachment K - ERRA 2016 Demand Response Metric* 6 provides the average hourly net cost CBP events called in the 2016 compliance period compared to the average hourly potential next cost from all times when trigger conditions were forecast (Dispatched or Not).

7. As described above in Section X, SDG&E utilized its DR programs during the record period primarily to reduce electricity consumption during peak demand or in response to system reliability needs. The instances in which SDG&E did not call events when triggers were met, were based on a combination of current system needs, and the benefit of reserving the resource to provide for a greater system need.

XI. CONCLUSION

My testimony describes SDG&E's plans and processes used during calendar year 2016 for serving load from its fully integrated portfolio of utility-owned resources, power purchase contracts and market transactions, consistent with the Commission-approved LTPP in effect for the record period. SDG&E consistently complied with the Commission's decisions addressing LCD practices during the 2016 record period. In summary, SDG&E's LCD processes satisfied the Commission's requirements by considering variable costs and utilizing the lowest-cost resource mix, subject to constraints in the day-ahead, hour-ahead and real-time markets. Therefore, SDG&E requests that the Commission find that SDG&E demonstrated compliance with the Commission's currently effective LCD and SOC 4 standards during the 2016 Record Period.

This concludes my prepared direct testimony.

XII. QUALIFICATIONS

My name is Joseph Pasquito. My business address is 8315 Century Park Court, San Diego, CA 92123. I am currently employed by SDG&E as a Market Analysis Manager. My responsibilities include the technical analysis of SDG&E's bundled load portfolio of supply assets for the benefit of retail electric customers. I assumed my current position in August 2014.

I previously was a senior electricity trader for SDG&E, primarily managing day-ahead and forward procurement of Electricity and Natural Gas. Prior to joining SDG&E in 2003, my experience included four years as an energy trader.

I hold a Bachelor's degree in Economics from the United States Naval Academy and a Masters of Business Administration with an emphasis in Finance from Georgia State University.

This is my first written testimony submitted to the Commission. I have not previously testified before the Commission.

I have previously testified before the Commission.

The following attachments are CONFIDENTIAL and are on the accompanying CD.

ATTACHMENT A

2016 Summary Load Data.xls

ATTACHMENT B

2016 Hydro and Pump Storage

ATTACHMENT C

Incremental Bid Cost Calculations.xslx

ATTACHMENT D

2016 Self Schedules Supporting Data 1.xlsx

ATTACHMENT E

2016 Self Schedules Supporting Data 2.xlsx

ATTACHMENT F

Master File (RDT) Change Exceptions.xlsx

ATTACHMENT G

2016 Annual Summary.xlsx

ATTACHMENT H

ERRA 2016 Demand Response Metric 1.xslx

ATTACHMENT I

ERRA 2016 Demand Response Metric 2.xslx

Attachment I

Total Energy Acutally Dispatched

Program	May	June	July	August	September	October	Total
CPB-DA Dispatched(MWh)	0	0	27	90	88	16	222
Total Available for Dispatch when Triggers Met(MWh)	0	0	11	140	90	29	270
Percentage Dispatched	0%	0%	239%	65%	98%	56%	82%

Program	May	June	July	August	September	October	Total
CPB-DO Dispatched(MWh)	0	22	61	24	32	0	140
Total Available for Dispatch when Triggers Met(MWh)	93	130	141	230	140	97	831
Percentage Dispatched	0%	17%	43%	11%	23%	0%	17%

ATTACHMENT J

ERRA 2016 Demand Response Metric 5.xslx

Attachment J

Total Net Cost Impact

Program	May	June	July	August	September	October	Total
CPB-DA	N/A	N/A	N/A	$ 383	$ -	$ -	$ 383
CPB-DO	$ 1,752	$ 6,779	$ 3,043	$ 19,136	$ 8,573	$ 6,940	$ 46,222

ATTACHMENT K

ERRA 2016 Demand Response Metric 6

Attachment K

Average Hourly Net Cost

Program	Average hourly net cost from actual dispatch events($/MWh)	Average hourly potential net cost from all times when trigger conditions were forecast(Dispatched or Not) ($/MWh)	$(A)-(B)	(A)/B (%)
CPB-DA	$ (8.80)	$ (8.40)	$ (0.41)	105%
CPB-DO	$ (105.76)	$ (68.74)	$ (37.02)	154%

BEFORE THE PUBLIC UTILITIES
COMMISSION OF THE STATE OF
CALIFORNIA

DECLARATION
OF JOSEPH PASQUITO

A.17-06-XXX

Application of San Diego Gas & Electric Company (U 902-E) for Approval of: (i) Contract Administration, Least Cost Dispatch and Power Procurement Activities in 2016, (ii) Costs Related to those Activities Recorded to the Energy Resource Recovery Account and Transition Cost Balancing Account in 2016 and (iii) Costs Recorded in Related Regulatory Accounts in 2016

I, Joseph Pasquito, do declare as follows:

1. I am the Market Analysis Manager for San Diego Gas & Electric Company ("SDG&E"). I have included my Direct Testimony ("Testimony") in support of SDG&E's Application for Approval of: (i) Contract Administration, Least Cost Dispatch and Power Procurement Activities, and (ii) Costs Related to those Activities Recorded to the Energy Resource Recovery Account, incurred during the Record Period January 1, 2016 through December 31, 2016, and (iii) the Entries Recorded in Related Regulatory Accounts. Additionally, as Market Operations Manager, I am thoroughly familiar with the facts and representations in this declaration and if called upon to testify I could and would testify to the following based upon personal knowledge.

2. I am providing this Declaration to demonstrate that the confidential information ("Protected Information") in support of the referenced Application falls within the scope of data provided confidential treatment in the IOU Matrix ("Matrix") attached to the Commission's Decision D.06-06-066 (the Phase I Confidentiality decision). Pursuant to the procedures adopted in D.08-04-023, I am addressing each of the following five features of Ordering Paragraph 2 in 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.] As such, the Protected Information provided by SDG&E is allowed confidential treatment in accordance with Appendix 1 - IOU Matrix in D.06-06-066.

Confidential Information	Matrix Reference	Reason for Confidentiality
Table 3-a Table 3-b	XI	Monthly Procurement Costs
Attachment A	VI.B XI II.A.2	Utility Bundled Net Open Position for Energy (for MWh), Confidential front three years Monthly Procurement Costs Utility Electric Price Forecast, Confidential for three years
Attachment B	IV.A VI.B	Forecast IOU Generation Resources, Confidential for three years Utility Bundled Net Open Position for Energy (for MWh)
Attachment C	II.B XI	Utility Retained Generation (URG) Confidential for three years Monthly Procurement Costs
Attachment D, E	XI	Monthly Procurement Costs

Attachment F	IX.B IV.A	Recorded data on specific resources (rather than broad categories of supply sources) used to serve bundled load; Appendix I IOU Matrix does not specify effective period of confidentiality. Forecast of IOU Generation Resources
Attachment G	XI VI.B	Monthly Procurement Costs Utility Bundled Net Open Position for Energy (for MWh)
Attachment H	II.A.2	Utility Electric Price Forecast

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. I 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 1 day of June, 2017, at San Diego, California.

Joseph Pasquito
Market Analysis Manager
San Diego Gas & Electric Company