PUBLIC VERSION

Application No.: A.15-06-xxx
Exhibit No.: ____________
Witness: Andrew Scates
Date: June 1, 2015

SAN DIEGO GAS & ELECTRIC COMPANY

PREPARED DIRECT TESTIMONY OF

ANDREW SCATES

REDACTED AND PUBLIC VERSION

BEFORE THE PUBLIC UTILITIES COMMISSION
OF THE STATE OF CALIFORNIA

June 1, 2015

#297396

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TABLE OF CONTENTS

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PREPARED DIRECT TESTIMONY OF

ANDREW SCATES

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, 2014, 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]

The 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, the Commission's primary least-cost dispatch standard, 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 2014, SDG&E has filed four quarterly advice letters ("AL") covering the record period (AL 2598-E, AL 2635-E, AL 2663-E, and AL 2696-E for Q1 through Q4 2014, respectively) as required in D.02-10-062. These advice letters provide detailed information on

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[1] For purposes of the Commission's review and the compliance findings requested herein, the relevant LTPP is SDG&E's 2012 LTPP, approved in Commission Resolution E-4543, in compliance with D.11-05-005, D.12-01-033 and D.12-04-046.

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

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 2014 were in compliance with SDG&E's Commission-approved LTPP and applicable procurement-related rulings and decisions.

SDG&E testimony and workpapers will demonstrate compliance with LCD based on the Interim Ruling Providing Guidance for 2014 ERRA Compliance Proceedings issued by Administrative Law Judge Roscow in Application ("A.") 11-06-003 ("Interim Ruling"). Based on the Interim Ruling, 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 will be provided 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;

  - o Total non-dispatchable capacity lost due to planned or forced outages.
  - o 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:
  - o 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 be dispatched but were not.
  - o 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.
  - o Total energy actually dispatched as a proportion of maximum available energy for each DR program broken down monthly and annually.
  - o Explanation as to why a DR resource was not dispatched due to its maximum availability.
  - o Cost impact on overall resource dispatch of not calling DR programs up to their maximum available amounts when program was forecasted to be triggered.
  - o Identify if selection of the DR events called minimized overall portfolio cost of dispatching supply resources.
  - o Explanation of SDG&E's opportunity cost methodology and demonstration of its application.

II. SDG&E PORTFOLIO OVERVIEW

For the record period, most of SDG&E's energy requirements were met with SDG&E PPAs and UOG. 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 Sally Chen. UOG 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 (with limited economic curtailment rights on two QF contracts). 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.

<u>Table 1: Must-Take Resources</u>

Resource	Capacity MW	Dispatch Profile	Ancillary Service Capability
QF contracts	247	Baseload with limited economic curtailment	None
Renewable non-intermittent resources	111	Baseload (as available)	None
Intermittent Resources	1759 (maximum)	Intermittent	None

Table 1: 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	603.5	Load Following	Spinning Reserve Regulation
Cuyamaca CT Natural Gas SP15	47	Peaker	Non-Spinning Reserve
Miramar 1 CT Natural Gas SP15	48	Peaker	Non-Spinning Reserve
Miramar 2 CT Natural Gas SP15	48	Peaker	Non-Spinning Reserve
Yuma QF Natural Gas NGila	56.5	Peaker	None
Orange Grove CT Natural Gas SP15	97	Peaker	Non-Spinning Reserve
El Cajon Energy Center CT Natural Gas SP15	47	Peaker	Non-Spinning Reserve
Escondido Energy Center (Wellhead) SP15	48	Peaker	Non-Spinning Reserve
Desert Star CCGT Natural Gas SP15	485	Load Following	Spinning Reserve
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 ("LSE") 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 process to meet new MRTU-related CAISO tariff rules and operating requirements while maintaining compliance with SOC 4, particularly in 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.

The CAISO market solves for the least cost unit commitment and dispatch solution incorporating self-schedules and economic bids from generators and load, various resource operational constraints and a full transmission network model that considers transmission constraints throughout the CAISO system. 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 its LCD optimization processes in more detail. 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.

[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.

> 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 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. SDG&E also submits self-schedules for its (non-intermittent resources) must-take resources in the day-ahead market.[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 day-ahead market 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 drives up the costs (which are charged to load) for these products that are necessary for grid reliability.

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[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.

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.

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 2014 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 begun 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 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.

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[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. <u>Master File Updates and Operating constraints</u>: 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. <u>Forecast of resource availability</u>: 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.

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.

Two QF contracts, Yuma Cogeneration Association ("YCA") and Goal Line, gave SDG&E limited curtailment rights when market prices were lower than the contract price for energy. Curtailment did not require these units to shut down; the QFs elected to either run and be paid the actual market price or shut down for the curtailment period. SDG&E included these curtailment provisions in its LCD and regularly monitored the difference between the market and contract prices to determine when maximum economic value could be obtained through QF curtailment.

The YCA QF contract provided for two types of economic curtailment: flexible and block. Flexible curtailments were limited to 2,200 hours per year with a minimum of eight hours per curtailment. The block curtailments were two 200 hour blocks per year. Since these curtailments had limitations of exercise, SDG&E used forward market and contract prices to forecast when the differential between these prices would be greatest in order to maximize cost savings. SDG&E updated its YCA QF curtailment analysis monthly as the QF energy price formula used a monthly gas price index as well as seasonal price shaping factors.

The Goal Line QF contract allowed SDG&E to economically curtail the contract for up to five hours each day of the year. If the forecasted off-peak energy price for energy was lower than the QF energy price for those hours, SDG&E provided Goal Line with a daily curtailment notice, which included a curtail price.

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. Load forecast: 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 lagged 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 the SLIC application as required.

c. Market prices: Spot natural gas and power trade actively in the day-ahead market. Updated prices fed into the model reflected actual market conditions to help in the forecasting of LMPs.

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 day-ahead market rather than rolling the requirement into the real-time market which produces more volatile prices. The day-ahead market 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 day-ahead market 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 - *2014 Summary Load Data.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 day-ahead market, 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 day-ahead market. 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. 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 day-ahead market 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.

- <u>Lake Hodges Pumped-Storage Unit</u>: 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 it 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 into SDG&E's scheduling application for submittal into the CAISO market.

SDG&E has provided Attachment B "2014 Hydro and Pump Storage" which includes summary reporting on bidding and dispatch of dispatchable hydro and pumped storage resources.

- Power Trades: During the 2014 compliance period, SDG&E primarily traded day-ahead financial power to hedge the risk of unknown day-ahead market 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 day-ahead market 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 the SLIC application 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 day-ahead market; if actual load exceeded the forecast, the result was a short real-time position;
- resources (must-take and dispatchable) that were awarded in the day-ahead market 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 day-ahead market 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 day-ahead market (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 day-ahead market 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 SLIC.

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 day-ahead market 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 showed 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 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 and the YCA and Goal Line QF contracts that allowed for economic curtailment for limited hours per day and per year.
- CAISO market solutions look at a 24 hour time horizons and in order 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 2014, 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 - *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 2014 Incremental Bid Cost Exceptions			
Month	**Number of Variances**	**% of Bids Submitted**	**Cost Impact**
Jan	1548	27.86%	[redacted]
Feb	952	19.14%	
Mar	1053	22.50%	
Apr	1493	31.64%	
May	1827	33.57%	
Jun	1320	27.50%	
Jul	1354	24.56%	
Aug	0	0.00%	
Sep	0	0.00%	
Oct	0	0.00%	
Nov	0	0.00%	
Dec	0	0.00%	
Total	**9547**	**14.43%**	

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 - *2014 Self Schedules Supporting Data 1.xlsx* and Attachment E - *2014 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.

[redacted]

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 - *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 2014 PROXY and Registered Cost Change Exceptions

Category	Proxy Elections	Registered Elections	Incorrect Submissions	Error Rate
Startup	11	202	0	0%
Minload	39	11	0	0%
Totals	**50**	**213**	**0**	**0%**

VII. MARKET DESIGN AND PROCESS CHANGES

The following is a brief summary of select CAISO market design changes and that have affected SDG&E's business processes during 2014:

1. FERC Order 764

FERC Order 764 directed balancing authorities ("Bas") to implement scheduling at intertie points on a 15 minute basis. On May 1, 2014 CAISO implemented 15-minute financially binding scheduling on interties and discontinued financial settlement in the Hour-Ahead Scheduling Process ("HASP"). The main effects on internal market and business processes were (1) intermittent resources may bid with economic flexibility instead of self-scheduling the CAISO's hour-ahead PIRP forecast as done prior to 764, (2) Intertie bidding is settled at the fifteen minute prices even if continuing to schedule or bid in one-hour blocks as is commonly done, (3) convergence bids are settled at an average of the four, fifteen minute market ("FMM") prices over the hour rather than the 12 five-minute RTD prices.

The introduction of the FMM resulting from Order 764 presented a considerable change in market processes, bidding considerations and business operations. SDG&E participated in stakeholder processes to review and advise on market changes. SDG&E updated its functionality and validated internal system changes to both front and back office operations through testing and participation in market simulations.

2. Commitment Cost Refinements

CAISO implemented updates to unit cost calculations, just prior to the 2014 record period, resulting from the Commitment Cost Refinements initiative. These updates allowed market participants to submit Greenhouse Gas ("GHG") and Major Maintenance Adder ("MMA") cost components under the proxy cost option. MMAs are generally contract-based numbers while the GHG cost element of startup and minimum load cost is based on physical average emissions.

The implementation of Commitment Cost Refinements required no changes to bidding and front office systems during the record period. As a result, the majority of SDG&E's efforts were participating in the stakeholder initiative process and market simulation to ensure business processes and bidding strategy were updated, and incorporating new rules.

3. Energy Imbalance Market

CAISO implemented the Energy Imbalance Market ("EIM") on November 1, 2014. The EIM integrated two PacifiCorp BAs into the CAISO real time market ("RTM"). Participation in the Integrated Forward Market ("IFM") day-ahead processes remains for internal generation, supply and interchanges at intertie points of the CAISO BA only. The implementation of the EIM expands the real-time market footprint substantially with the goal of achieving efficient trading between BAs. In order to integrate a larger network footprint, CAISO expanded the network model it uses to evaluate the transmission flows and new supply and demand nodes in PacifiCorp BAs.

The implementation of the EIM did not require any market system changes for SDG&E's market participation. SDG&E's main efforts during the scoping and implementation of the EIM were to take part in stakeholder processes, participate in market simulation and verify settlements data.

The following is a brief summary of select SDG&E process changes during the compliance period:

1. As stated in the previous section, FERC Order 764 created the new FMM market process and changed bidding and scheduling of intermittent resources.

   Participation in the CAISO stakeholder's process helped SDG&E's efforts to appropriately modify daily front- and back-office processes and to accommodate the market change.

2. More formal bid validation procedures, using PCI's Bid Evaluator module, were developed to ensure CAISO market solutions were justified, explainable and in compliance with LCD. More specifically, on a daily basis, Bid Evaluator reports were analyzed and all significant variances were recorded in a log, pursued until there was resolution or justification, and then evaluated by the Market Analysis Manager and the Market Operations Manager for approval.

VIII. ANNUAL TABLE

3. 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 - *2014 Annual Summary.xlsx* 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 day-ahead market awards.

Table 5
Background Summary- 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	17,625,821	3,480,250	792,448	7,469,011	8,261,459
Dispatchable	Pump Hydro	351,714	27,798	(11,913)	0	(11,913)

Non-Dispatchable	Resource Type	Capacity (PMAX in MWh)	Unavailable Capacity (MWh)	DA SS Awards (MWh)	Award due to Market	Total Awards
Non-Dispatchable	BioGas	252,726	-	174,705	7,683	182,388
Non-Dispatchable	Bio-mass	105,120	625	70,103	33	70,136
Non-Dispatchable	Conduit Hydro	43,800	-	18,632	0	18,632
Non-Dispatchable	Digester Gas	42,311	-	17,527	0	17,527
Non-Dispatchable	Natural Gas Generation	1,675,788	2,630	815,974	0	815,974
Non-Dispatchable	Other	1,091,321	-	220,793	0	220,793
Non-Dispatchable	Solar	8,252,796	32,155	1,345	768,133	769,478
Non-Dispatchable	Wind	3,648,014	90	11	158,109	158,120
Grand Total		**33,089,411**	**3,543,548**	**2,099,626**	**8,402,969**	**10,502,594**

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 all dispatchable resources. These included SDG&E-owned or -contracted resources (Miramar, Cuyamaca, Palomar, Desert Star, OMEC, Orange Grove, Escondido Energy Center, and El Cajon Energy Center). 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, SDG&E at all times 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 day-ahead market 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 2014 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 least cost dispatch 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.

SDG&E procured SoCalGas system storage capacity (in 2013) that was in effect from April 1, 2013 through March 31, 2014. SDG&E also bid for and was awarded SoCalGas system storage capacity (in 2014) that was in effect from April 1, 2014 through March 31, 2015. Storage was required to manage day-to-day imbalances between natural gas deliveries and actual consumption that occurred on a daily basis. Imbalances were mainly caused by CAISO-instructed incremental or detrimental real-time dispatches that deviated from the day-ahead LCD forecast. Significant imbalances resulted from time to time as a result of a forced outage on a large unit. Gas storage helped SDG&E fuels traders respond to such events by providing an operational alternative for managing its balancing requirements rather than relying on trades with other market participants. The value of this operational flexibility was even more pronounced when the pipeline declared operating restrictions to force market participants to balance their gas deliveries with consumption. SDG&E's awarded storage bid was based on cost savings associated with this flexibility as well as the summer/winter price spread.

Natural gas trading and scheduling processes remained largely intact through MRTU implementation. However, the day-ahead market process increased the uncertainty of gas quantities to be traded in the day-ahead market. 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 be more costly 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 2014, SDG&E utilized its demand response 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. Pusuant to the Interim Ruling discussed above, SDG&E's Capacity Bidding Program ("CBP"), a demand response program, is subject to the LCD standard as it has economic triggers. However, SDG&E's Summer Saver Program ("SSP"), does not have economic triggers, and therefore is not subject to the LCD standard. In the remainder of this section, SDG&E provides information pertaining to the CBP and SSP programs in SDG&E's DR portfolio and how the two programs were utilized in 2014.

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 electric system supply portfolio reaches a resource dispatch equivalence of 15,000 Btu/kWh heat rate; 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 system demand and customer fatigue into account before making a final decision about whether or not to dispatch the program.[8]

The CBP was activated on twenty (20) occasions during the 2014 event season. Thirteen (13) events were Day-Ahead and seven (7) were Day-Of. In all cases when CBP events were initiated during the record year of 2014, the quantified economic triggers from the tariff were met and SDG&E determined that the system needs warrant such actions.

<u>Summer Saver Program (“SSP”)</u>

Summer Saver Program (SSP) is available to residential and small business customers with HVAC units. The program is operational from May 1st through October 31st, including the weekends and holidays, and is available from noon to 8:00 p.m. Participants receive an annual bill credit at the end of the event season based on customers’ cycling options. A maximum of 15 events may be called during event season. Events may be no less than 2 hours and no more than 4 hours between noon and 8:00 p.m. Events may not be called for more than 3 days in any given calendar week; no more than 40 hours per month.

In 2014, SDG&E called upon the SSP participants on eight (8) occasions due to high system demands. The SSP program specifies event triggers that are not economic factors. Instead, the program has an operational trigger of the system load of 3800 MWs as well as the limitations described above in regards to calling events. The SSP is not a program that has an economic trigger, and accordingly is not subject to the Commission’s LCD requirements.

In accordance with the Interim Ruling Providing Guidance for 2014 ERRA Compliance Proceedings, SDG&E has included the following demand response metrics.

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[8] See Also Rebuttal testimony of Liying Wang in response to ORA’s testimony in SDG&E’s 2013 Energy Resource Recovery Account (“ERRA”) Review Application (“A.14-05-026”).

DEMAND RESPONSE METRICS

1. An annual summary of the results of the reporting requirement (related to dispatch of DR resources) recently 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 actually 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 actually 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 2014 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 2014 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 and 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 utiltiy'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.*

Below is the description of the metrics SDG&E supplied in workpapers in order to comply with the Interim Ruling.

1. Attachment H - *ERRA 2014 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 2014 compliance period, SDG&E used the Day-Ahead market clearing prices as the forecast trigger criteria for CBP Day-Ahead because he 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 Day-Ahead market 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 2014 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 2014 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 and event.

5. Attachment J - *ERRA 2014 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 2014 Demand Response Metric* 6 provides the hourly net cost CBP events called in the 2014 compliance period compared to the 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 demand response programs during the record period primarily to reduce electricity consumption during peak demand or in response to system reliability needs. The instances where 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 in times of greater need. SDG&E will continue to improve this process as it begins to bid CBP into the CAISO market.

SDG&E has provided similar information in the Commissions DR Rulemaking (R.) 13-09-011. Decision 14-05-025 requires SDG&E and other Investor-Owned Utilities to submit weekly DR dispatch exception reports to identify and describe each occurrence when a DR program hit triggers but were not dispatched. SDG&E also provided the DR dispatch exception report for the 2014 record period.

XI. CONCLUSION

My testimony describes SDG&E's plans and processes used during calendar year 2014 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 2014 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 2014 Record Period.

This concludes my prepared direct testimony.

XII. QUALIFICATIONS

My name is Andrew Scates. My business address is 8315 Century Park Court, San Diego, CA 92123. I am currently employed by SDG&E as a Market Operations Manager. My responsibilities include overseeing a staff of schedulers involved in dispatching the SDG&E bundled load portfolio of supply assets for the benefit of retail electric customers. This includes operational administration of DWR contracts, transacting in the real-time wholesale market and managing scheduling activities in compliance with CAISO requirements. I assumed my current position in January 2011.

I previously managed the Electric Fuels Trading desks for SDG&E, primarily managing day ahead and forward procurement of Natural Gas. Prior to joining SDG&E in 2003, my experience included five years as an energy trader/scheduling manager.

I hold a Bachelors degree in Business Administration with an emphasis in Finance from California State University, Chico.

I have previously testified before the Commission.

PUBLIC VERSION

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

Attachment A

2014 Summary Load Data.xls

ATTACHMENT B

2014 Hydro and Pump Storage

ATTACHMENT C

Incremental Bid Cost Calculations.xslx

ATTACHMENT D

2014 Self Schedules Supporting Data 1.xlsx

ATTACHMENT E

2014 Self Schedules Supporting Data 2.xlsx

ATTACHMENT F

Master File (RDT) Change Exceptions.xlsx

ATTACHMENT G

2014 Annual Summary.xlsx

ATTACHMENT H

ERRA 2014 Demand Response Metric 1.xslx

PUBLIC VERSION

ATTACHMENT I

ERRA 2014 Demand Response Metric 2.xslx

Attachment I

Total Energy Acutally Dispatched

Program	May	June	July	August	September	October	Total
CPB-DA Dispatched(MWh)	95	0	66	101	126	0	387
Total Available for Dispatch when Triggers Met(MWh)	126	61	361	176	252	189	1,165
Percentage Dispatched	75%	0%	18%	57%	50%	0%	33%

Program	May	June	July	August	September	October	Total
CPB-DA Dispatched(MWh)	70	0	0	0	154	0	224
Total Available for Dispatch when Triggers Met(MWh)	104	112	360	135	339	209	1,259
Percentage Dispatched	67%	0%	0%	0%	45%	0%	18%

PUBLIC VERSION

ATTACHMENT J

ERRA 2014 Demand Response Metric 5.xslx

Attachment J

Total Net Cost Impact

Program	May	June	July	August	September	October	Total
CPB-DA	$ 31	$ 367	$ 2,106	$ 422	$ 403	$ 2,018	$ 5,346
CPB-DO	$ 79	$ 1,949	$ 11,746	$ 2,505	$ 3,902	$ 9,058	$ 29,239

PUBLIC VERSION

ATTACHMENT K

ERRA 2014 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	$ (15.31)	$ (9.72)	$ (5.59)	157%
CPB-DO	$ (74.26)	$ (36.73)	$ (37.53)	202%

BEFORE THE PUBLIC UTILITIES
COMMISSION OF THE STATE OF CALIFORNIA

DECLARATION
OF ANDREW SCATES

A.15-06-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 2014, (ii) Costs Related to those Activities Recorded to the Energy Resource Recovery Account and Transition Cost Balancing Account in 2014 and (iii) Costs Recorded in Related Regulatory Accounts in 2014

I, Andrew Scates, do declare as follows:

1. I am the Market Operations 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, 2014 through December 31, 2014, 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.[1] 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 2- Column-Cost Impact	XI	Monthly Procurement Costs (Energy Resource Recovery Account) Confidential for three years
Table 3-a Table 3-b	XI	Monthly Procurement Costs (Energy Resource Recovery Account) Confidential for three years
Attachment A	VI.B	Utility Bundled Net Open Position for Energy(for.MWh)
	XI	Monthly Procurement Costs (Energy Resource Recovery
Attachment B	IV.A VI.B	Forecast IOU Generation Resources Utility Bundled Net Open Position for Energy(for.MWh)
Attachment C	II.B XI	Utility Retained Generation (URG) Confidential for 3 years Monthly Procurement Costs (Energy Resource Recovery Account) Confidential for three years
Attachment D and E	XI	Monthly Procurement Costs
Attachment F-	IV.A IX.B	Forecast of IOU Generation Resources Recorded data on specific resources (rather than broad

[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 such data under those provisions, as applicable.

		categories of supply sources) used to serve bundled load; Appendix I IOU Matrix does not specify effective period of confidentiality.
	XI	Monthly Procurement Costs (Energy Resource Recovery)
Attachment G	XI	Monthly Procurement Costs
	VI.B	Utility Bundled Net Open Position for Energy(for.MWh)
Attachment H	II.A	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 29th day of May, 2015, at San Diego, California.

Andrew Scates
Market Operations Manager
San Diego Gas & Electric Company