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Witness: Andrew Scates

Date: June 1, 2011

SAN DIEGO GAS & ELECTRIC COMPANY

PREPARED DIRECT TESTIMONY OF

ANDREW SCATES

REDACTED VERSION

BEFORE THE PUBLIC UTILITIES COMMISSION

OF THE STATE OF CALIFORNIA

June 1, 2011

SDGE

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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's") compliance with least-cost dispatch ("LCD") requirements during the Record Period of January 1 through December 31, 2010, as specified by applicable 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"), power purchase contracts and allocated California Department of Water Resources ("DWR") contracts. The following chapters describe Commission orders on LCD and how SDG&E implemented these orders in a manner consistent with its Commission-approved Long-Term Procurement Plan ("LTPP").[1]

SDG&E has filed four quarterly advice letters covering the Record Period (AL 2187-E, AL 2168-E, AL 2202-E, and AL 2228-E for Q1 through Q4 2010, respectively) as required by the Master Data Request in D.02-10-062. 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. The Commission's Utility Audit, Financial, and Compliance Branch (UAFCB) has completed its compliance audits of all four of SDG&E's Quarterly Compliance Reports ("QCR") for 2010, concluding that SDG&E's QCR transactions for electricity and natural gas were materially complete, accurate, properly authorized and in compliance with SDG&E's Commission-approved procurement plan and all relevant Commission decisions. Moreover, with the exception of SDG&E's Q4 QCR, for which approval is currently pending, the Commission's Energy Division issued its approvals establishing that the procurement transactions reflected in SDG&E's QCRs were in compliance with SDG&E's Commission-approved LTPP, and applicable procurement-related rulings and decisions.[2]

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[1] SDG&E's LTPP was approved in D.07-12-052. The compliance filing was approved in Resolution E-4189 on September 4, 2008. It has been subsequently modified by two Advice Letters, AL 2061-E in January 2009, and AL 2067-E in [insert month and year, both approved by the Energy Division.

[2] D.02-10-062, COL 7, p. 73; D.03-12-062, pp. 78-79; OP 20 and, D.07-12-052, pp. 185 -192.

II. COMMISSION DIRECTION FOR LEAST COST DISPATCH

In D.02-09-053, which allocated the DWR contracts to the three California investor owned utilities ("IOUs"), the Commission charged the IOUs with the responsibility to "assume all the operational, dispatch and administrative functions"[3] for the allocated contracts and directed that "economic dispatch shall be the operating rule for the utility's portfolio of resources, including the DWR contracts."[4] This decision also provided direction by which a utility should implement LCD of the combined utility/DWR portfolio. D.02-09-053 states: "[E]conomic dispatch entails analysis of the marginal costs of the available energy and dispatching the least-cost incremental resource. An important element of least cost dispatch is that the fixed costs associated with resources are considered sunk for dispatch purposes. Variable costs are the only ones that are incurred or avoided as a result of operating decisions."[5]

The LCD requirement was reiterated by the Commission in D.02-10-062, which authorized the IOUs to resume full procurement responsibilities on January 1, 2003. That decision established standards of conduct by which an IOU must administer its portfolio, including the allocated DWR contracts. Specifically, Standard of Conduct #4 ("SOC 4") states that "[t]he utilities shall prudently administer all contracts and generation resources and dispatch the energy in a least-cost manner."[6] Disallowances for violations of SOC 4 are subject to a cap equal to twice the IOU's annual expenditure on all procurement activities.[7]

The Commission provided further guidance on LCD by affirming that "least cost" activities include the purchase and sale of power to achieve the most cost-effective mix of resources and minimize cost to ratepayers:

> Prudent contract administration includes administration of all contracts within the terms and conditions of those contracts, to include dispatching dispatchable contracts when it is most economical to do so. In administering contracts, the utilities have the responsibility to dispose of economic long power and to purchase economic short power in a manner that minimizes ratepayer costs. Least-cost dispatch refers to a situation in which the most cost-effective mix of

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3 D.02-09-053, Ordering Paragraph 2.
4 D.02-09-053, Ordering Paragraph 5.
5 D.02-09-053, p. 30-31.
6 D.02-10-062, p. 51 and Conclusion of Law 11, p. 72.
7 D.03-06-067, Ordering Paragraph 3 (a).

> total resources is used, thereby minimizing the cost of delivering electric services.
>
> The utility bears the burden of proving compliance with the standard set forth in its plan.[8]

Additional LCD guidance was provided in R.04-04-003 in response to a CAISO request that the IOUs assist with the management of intra-zonal congestion. R.04-04-003 established that the IOUs account for intra-zonal congestion in their procurement and scheduling decisions to mitigate the CAISO's reliability concerns. R.04-04-003 was followed by D.04-07-028, requiring IOUs to assess the potential for intra-zonal congestion when procuring and scheduling resources. In response to D.04-07-028, SDG&E filed Advice Letter 1641-E on 12/3/2004 describing its revised LCD procedure incorporating a new cost adder to account for anticipated intra-zonal congestion costs.

Finally, with regard to review of LCD transactions in ERRA proceedings, the Commission determined in D.05-01-054 (SDG&E's 2004 ERRA compliance decision) that the scope of LCD review should cover the dispatch of resources in the day-ahead, hour-ahead and real-time markets. The Commission reiterated this scope of review in D.05-04-036 (PG&E's 2004 ERRA compliance decision).

III. PRINCIPLES OF LEAST COST DISPATCH

The goal of least cost dispatch is to minimize ratepayer cost for energy and ancillary services (A/S) given prevailing market conditions. SDG&E achieved this objective by planning, trading, scheduling and bidding to economically optimize the dispatch of its resources and market transactions to lower overall cost. Planning involves a thorough assessment of the portfolio's dispatch economics to determine the lowest cost mix of resources to meet forecasted load. Trading makes least cost dispatch "happen" by finalizing resource schedules and executing economic market transactions, including sales of surplus generation above variable cost. Scheduling and bidding enables the CAISO markets to dispatch resources in line with variable operating costs in real-time. Performance of these functions essentially embodies the least cost principles established by the Commission. How SDG&E performs each of these functions is discussed in the following sections.

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[8] D.03-06-076 at p. 23.

A crucial footnote is that there are numerous constraints that impede SDG&E's ability to perfectly adhere to these least cost dispatch principles. SDG&E must balance its objective of cost minimization with a number of constraints both within and outside the portfolio. They include generator operating limits, regulatory requirements, risk mitigation and other drivers that are discussed in Section IX.

IV. CAISO MARKET OVERVIEW

The CAISO implemented MRTU, now called simply the Market on April 1, 2009, which fundamentally changed several processes that impact least cost dispatch. The most significant of these changes was the implementation of forward markets, which transferred to the CAISO the responsibility to determine day-ahead and intraday unit commitment and dispatch decisions (also referred to as "awards") for resources based on economic bids. The CAISO operates the day-ahead and intraday markets that establish commitment, energy and A/S obligations on resources in the system. These markets derive generation awards from supply and demand bids and self-schedules submitted by market participants. The results reflect a least cost dispatch solution across the entire system because the CAISO selects the mix of resources with the lowest total variable cost (as represented by their bids) to meet load requirements, subject to reliability and operational requirements.

Another significant market feature is that day-ahead awards on resources and load are financially binding obligations. Deviations between these awards and actual energy delivery (or load consumption) trigger settlement charges with the CAISO at real-time prices, as described further in Section VIII.D of this testimony. The CAISO market solves for the day-ahead and intraday commitment and dispatch solution based on a full transmission network model that considers transmission constraints throughout the CAISO system. The awards explicitly account for the economic effects of congestion (e.g., cost to re-dispatch resources to relieve congestion constraints). The congestion cost is published for each of the several thousand price nodes in the CAISO system. The day-ahead market 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.[9] The resulting allocation of awards between generation and A/S across the system therefore reflects the economic tradeoff between capacity used for generation and that reserved for A/S.

During the Record Period, SDG&E primarily traded day-ahead financial power to hedge *ex-ante* the risk of unknown day-ahead market clearing prices, due to greater liquidity for these products versus physical power. Like physical power purchases, SDG&E purchased financial power to lock in energy prices below its marginal generation cost, and sold financial power to lock in sales of surplus generation above variable cost. SDG&E traded these products on the Intercontinental Exchange ("ICE") or through voice brokers to ensure competitive prices, and submitted these trades for Commission review in its Quarterly Compliance Reports.

V. SDG&E PORTFOLIO OVERVIEW

For the Record Period, most of SDG&E's energy requirements were met with SDG&E-contracted purchase power agreements ("PPAs"), utility-owned generation and allocated DWR contracts. SDG&E's PPAs included Qualifying Facility (QF) contracts and contracts for renewable energy contracts, dispatchable generation and out-of-state resources. Utility-owned generation included a 20% share of SONGS, Palomar Energy Center combined-cycle plant and Miramar 1 and 2 combustion turbine (CT) generators. Allocated DWR contracts included two wind contracts, three CTs and the Sunrise combined cycle plant.

For the Record Period, the most significant changes to SDG&E's portfolio were the addition of PPAs for Orange Grove (99.2 MW), El Cajon Energy Center (48 MW), Blue Lake (11 MW), Wellhead Escondido (35 MW) and the expiration of two DWR must-take contracts (325 MW.

The table below provides summary data for resources in the SDG&E/DWR portfolio and highlights key changes resulting from the transition to new Market.

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9 As a simple example, if a generator's energy bid price is $10/MWh in-the-money relative to the clearing price, then the IFM will 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.

Must-Take Resources

Resource	Capacity MW	Dispatch Profile	Ancillary Service Capability
SONGS (nuclear)	450	Baseload	None
QF contracts	221	Baseload w/ limited economic curtailment	None
Renewable (non-wind) contracts Add Blue Lake	97	Baseload (as available)	None
Renewable wind contracts (includes DWR wind contracts)	217 (maximum)	Intermittent	None
System Resource imports	203	Baseload (7x24)	None

*Although located in San Diego County, SONGS is electrically not a San Diego local resource.

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Dispatchable Resources

Resource*	Capacity MW	Dispatch Profile	Ancillary Service Capability
Palomar CCGT Natural Gas SP26	566	Load Following	Spinning Reserve Regulation
Otay Mesa CCGT Natural Gas SP26	604	Load Following	Spinning Reserve Regulation
Sunrise CCGT Natural Gas ZP26	590	Load Following	None
Calpeak Border CT* Natural Gas SP26	49	Peaker	None
Calpeak El Cajon CT Natural Gas SP26	45	Peaker	None
Calpeak Escondido CT Natural Gas SP26	48	Peaker	None
Miramar 1 CT Natural Gas SP26	48	Peaker	Non-Spinning Reserve
Miramar 2 CT Natural Gas SP26	48	Peaker	Non-Spinning Reserve
Boardman Coal ST Coal Malin	83	Baseload	None
Encina Unit 1 ST Natural Gas SP26	106	Peak Load Following	Spinning Reserve
Encina Unit 2 ST Natural Gas SP26	104	Peak Load Following	Spinning Reserve Regulation
Encina Unit 3 ST Natural Gas SP26	110	Peak Load Following	Spinning Reserve Regulation
Encina Unit 4 ST Natural Gas SP26	300	Peak Load Following	Spinning Reserve Regulation
Encina Unit 5 ST Natural Gas SP26	330	Peak Load Following	Spinning Reserve Regulation
Encina CT Natural Gas SP26	15	Peaker	Non-Spinning Reserve
Orange Grove Energy, LLC CTNatural Gas SP26	99.9	Peaker	Non-Spinning Reserve
El Cajon Energy Center CT	48	Peaker	Non-Spinning Reserve

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*CCGT = Combined Cycle Gas Turbine; CT = Combustion Turbine; ST = Steam Turbine

VI. SDG&E-OWNED GENERATION

During the Record Period, SDG&E operated and maintained its utility-owned generation resources (Palomar, Miramar 1 and 2)[10] in a reasonable and prudent manner, consistent with good utility practice. A definition for good utility practice was adopted by the Commission as part of SDG&E's Operating Order with DWR, approved in D.02-12-069[11]:

> "[A]ny of the practices, methods and acts engaged in or approved by a significant portion of the electric utility industry during the relevant time period, or any of the practices, methods and acts which, in the exercise of reasonable judgment in light of the facts known at the time the decision was made, could have been expected to accomplish the desired result at a reasonable cost consistent with good business practices, reliability, safety and expedition. Good Utility Practice does not require the optimum practice, method, or act to the exclusion of all others, but rather is intended to include acceptable practices, methods, or acts generally accepted in the Western Electric Coordinating Council region.

SDG&E established and followed a maintenance program to maximize the availability of the units as a primary "desired result". Specifically, this maintenance program balanced a number of considerations, including manufacturer guidelines, appropriate power industry practices, safety considerations, and good technical judgment to allocate resources most effectively to maximize availability. Some of these maintenance requirements required planned outages, while corrective maintenance was performed under short-notice or forced outages.

Despite SDG&E performing maintenance on its generation resources consistent with Good Utility Practice, these units experienced forced outages from time to time due to unforeseen operational problems. Forced outages in 2010 of 24 hours or greater are described in Appendix 1. When SDG&E experienced a forced outage on Palomar, Miramar 1 or 2, or any other resource in its portfolio[12], it responded to the event based on LCD principles. To the extent feasible based on scheduling, market liquidity and other constraints, SDG&E sought to replace lost generation due to forced outages at the minimum cost. This process is discussed in Section VIII.D.

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[10] SDG&E owns 20% of SONGS but the plant is operated and maintained by the Southern California Edison Company ("SCE"). Accordingly, facts related to SONGS' operations and maintenance, including forced outages, can be obtained from SCE.

[11] See Attachment A-3 of D.02-12-069 at p. 5.

[12] Including is 20% share of SONGS.

VII. FUEL PROCUREMENT

During the Record Period, SDG&E supplied fuel to all natural gas-fire dispatchable resources in the portfolio. SDG&E performed as the pipeline-registered Fuel Manager and Fuel Supplier for all non-DWR dispatchable resources (Miramar peakers, Palomar, Otay Mesa, Encina, Orange Grove, and ECEC). SDG&E also performed both Fuel Manager and Fuel Supplier functions as DWR's agent for Sunrise and the Calpeak units. Fuel costs for SDG&E resources are charged to ERRA, while fuel costs for DWR resources are paid by DWR and recovered through the DWR retail remittance rate. No preference is given to either SDG&E or DWR resources despite the difference in fuel cost recovery mechanism; SDG&E dispatches all units based strictly on variable dispatch costs and operational constraints.

As discussed in the Commission-approved LTPP and SDG&E / DWR Gas Supply Plan, SDG&E's procurement strategy 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 intraday market prices to price out day-ahead or intraday 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 fuel relative to real-time requirements, fuels traders sold the surplus baseload supply at the same-day market price. This coordination between the fuels and power desks 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 use natural gas supplied at these points (except Sunrise Power

Plant). All natural gas transactions were reported and are reviewed by the Commission in SDG&E's Quarterly Compliance Reports under the advice letters cited in Section I.

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 NGI SoCal Border index. Futures trades were executed through the NYMEX exchange. 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. Prior to finalizing a basis swap directly with a counterparty, SDG&E simultaneously secured competitive offers from two to six other sellers to ensure the swap was priced competitively. These hedge transactions complied with the LTPP and internal quarterly hedge plans, and were submitted for Commission review in SDG&E's Quarterly Compliance Reports.

Throughout the Record Period, SDG&E held approximately [redacted] MMBtu/day of Firm Access Rights ("FARs") to transport natural gas from the various SoCal Border trading points to the SoCalGas Citygate. SDG&E purchased the FAR capacity from SoCalGas pipeline to increase the priority of fuel delivery to its dispatchable resources. The quantity of FARs represented a forecast of the average daily fuel usage of these resources over the year. If fuel requirements were less than the FAR quantity on a given day, SDG&E sought to mitigate the capacity cost by monetizing the FARs via locational spreads (purchase at SoCal Border and sale at SoCalGas Citygate) in the day-ahead market when the spread exceeded transaction costs. SDG&E submitted Advice Letter 1983-B on July 3, 2008 to amend its LTPP to include FARs as a Commission-approved product to serve load.

SDG&E also bid for and was awarded SoCalGas system storage capacity that was in effect from April 1 through December 31 of the Record Period. 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 decremental 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. As with all other fuels-related products, SDG&E complied with its LTPP in procuring gas storage capacity.

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 sufficiently, fuels traders had to trade and/or schedule gas supplies in later pipeline scheduling cycles to avoid potential imbalance penalties. Activity in these later scheduling cycles typically added to the overall cost of fuel supply due to lower availability of competitive bids and offers.

VIII. LEAST COST DISPATCH PROCESS

Least cost dispatch activities were managed within SDG&E by the Electric & Fuels Department ("E&FP"). Key personnel involved in daily LCD activity included fuels traders and schedulers, power traders, preschedulers and real-time schedulers. The LCD process consisted of a number of parallel and sequential processes, which are described in this section.

A. Weekly LCD Plan

LCD 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[13] was set up with numerous parameters, including load forecast, plant operating data, resource availability, market prices and dispatch constraints, which allowed the model to perform complex analysis that resulted in a preliminary forecast of generation dispatch and market transactions that minimized total variable cost to serve the forecasted load requirement.

[13] SDG&E uses GenTrader, a leading 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 across the country in nodal and traditional markets to optimize generation portfolios. Additional product description is available at http://www.powercosts.com/products/gentrader.asp.

The model produced expected utilization of resources for the planning horizon, including dispatch levels, fuel requirements and market transactions. The model output was reviewed by several sections within E&FP, including Energy Supply & Dispatch, Energy Risk Management and Settlements & Systems, to ensure that results were consistent with LCD standards.

A detailed description of the inputs to the LCD model follows:

a. Load forecasts: Load forecasts were performed along several time frames: 12 days ahead, one day-ahead and intra-day in advance of the actual operating hour. E&FP utilized Advanced Artificial Neural-Network Short-Term Load Forecaster ("AANNSTLF"), a computer program developed by Pattern Recognition Technologies, Inc. for the Electric Power Research Institute ("EPRI"). In 2010, ANNSTLF was upgraded to the latest available version and the model was retrained in order to produce the most accurate forecast possible. In addition, users were provided instruction on both new and existing features within ANNSTLF, including analysis and error correction procedures. This application analyzes relationships between historical system load and weather data, and develops an hourly load forecast. The program was updated as frequently as each hour as actual load and weather data were collected and temperature and humidity forecasts were updated by SDG&E's weather forecasting service provider.[14] SDG&E monitored the accuracy of its load forecast on an hourly basis and made corrective adjustments to its results as warranted to account for changing load patterns. SDG&E's load forecast for bundled customers served by E&FP was comprised of the SDG&E system load less transmission losses, which were calculated as a percentage estimate of the system load forecast based on historical data, less the load forecast for Direct Access customers. The Direct Access load forecast was provided twice a week by SDG&E's Strategic Analysis and Pricing department. The forecast was based on the current Direct Access accounts in the SDG&E billing system and the historic load for those accounts.

b. Resource operating parameters: The model required a variety of data for each dispatchable resource to properly determine its dispatch cost. Such data included heat

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[14] SDG&E subscribes to MDA EarthSat's weather forecasting service. MDA EarthSat is a national weather service firm that provides SDG&E with customized weather data and forecasts. Energy Supply & Dispatch personnel communicate by phone with MDA EarthSat meteorologists on a daily basis.

rates, minimum and maximum operating points, fuel delivery charges and start-up costs. Numerous operating constraints were also fed into the model including start-up time, minimum shutdown and run times and ramp rates. The 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 portfolio is comprised of must-take resources (nuclear, QF and renewable energy) and fixed-quantity transactions, as listed in Section V. SDG&E receives weekly, and in some cases daily, forecasts of hourly deliveries from the resource operator. SDG&E generates availability forecasts for some smaller contracts based on historical performance.

d. Market prices: The LCD 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. Fuel prices were based on forward natural gas price curves at SoCal Border and Opal (derived from NYMEX, 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. Other factors that affected the model results included congestion, hourly price weighting profile, SRAC prices for QF economic curtailments and contract or regulatory limits that imposed additional constraints on economic dispatch. Use-limited resources including certain peakers, demand response products and limited economic curtailment of the YCA contract, required a separate optimization that was performed over a longer time horizon than the 12-day LCD modeling process. These results were then fed into the model as inputs.

GenTrader then ran an optimization algorithm to calculate the hourly dispatch level of each dispatchable resource over the modeled period that was economic, or "in-the-money," relative to market 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 described above. 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, 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 least cost dispatch and regularly monitored the difference between the market and contract prices to determine when maximum economic value could be obtained through QF curtailment.

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 off-peak price for SP15 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.

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 8 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 uses a monthly gas price index as well as seasonal price shaping factors. In the Record Period, SDG&E used all 2,200 hours of its flexible curtailment hours during off-peak and shoulder month hours, and a 200 hour block curtailments in January/February 2010 and a 200 block curtailment in March 2010.

B. Day-Ahead LCD Plan

On a day-ahead basis by approximately 6:00 a.m., preschedulers updated the GenTrader 12-day model with updated values, specifically the load forecast, market prices and resource availabilities. Other data such as resource operating constraints 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 ANNSTLF load forecasting model. In addition, pre-schedulers applied manual adjustments to the ANNSTLF result when warranted to offset known limitations to the model. For example, because ANNSTLF forecasts are based on historical data, ANNSTLF lagged sudden changes to the weather forecast such as the onset of a heat wave. The prescheduler also benchmarked the ANNSTLF 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 and forced derates and outages.

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 rather than a price forecast.

GenTrader 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.

C. Day-Ahead Trading and Dispatch

The CAISO Market uses a day-ahead market ("DAM") to economically clear load and resources that were scheduled or bid. As described in Section IV, the DAM resulted in significant changes to day-ahead least-cost dispatch. 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, and the sum of SDG&E's cleared resources did not necessarily balance with SDG&E's load award. Scheduling of load and (non-wind) must-take resources remained substantively unchanged from pre-MRTU scheduling. For wind and dispatchable resources, SDG&E currently has scheduling and bidding protocols, as discussed below.

- Load: In the new Market, SDG&E chose to adopt a risk-mitigating strategy by self-scheduling load to 100% of the day-ahead forecast. Self-scheduling ensured that SDG&E would purchase its entire forecasted load requirement in the day-ahead market rather than rolling the requirement into the real-time market. The day-ahead market was preferred for several reasons. The first is that the overall market cleared most of its load and resources in the day-ahead market; this market depth helped ensure that clearing prices reflect competitive supply bids. The second reason was that SDG&E also scheduled or bid most of its resources into the day-ahead market. Therefore, while balanced schedules were not strictly required, day-ahead supply quantities that cleared effectively offset the day-ahead costs assessed to the cleared load quantity. The third reason for clearing load in the DAM was to avoid a CAISO-assessed underscheduling charge. With certain exceptions, 85% of actual (metered) load was required to clear in the DAM to avoid an underscheduling charge.[15] If the DAM award was less than 85%, the shortfall quantity (85% of actual load minus the DAM award) was assessed with an underscheduling charge which ranges from $150 to $250/MWh depending on the shortfall quantity.

- Non-wind 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 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.
- Wind generation: All SDG&E wind resources were scheduled by sellers participating in the Participating Intermittent Resource Program ("PIRP"). PIRP requires that participating resources schedule the final generation forecast published by PIRP in the Hour-Ahead Scheduling Process ("HASP"). The new Market has complicated the scheduling process for wind generation due to the introduction of financially binding obligations on day-ahead generation schedules, and caused sellers to stop scheduling wind generation in the day-ahead market. The result is that under the Market all sellers began scheduling wind generation only in the HASP. The CAISO pays the real-time market clearing price for such schedules, rather than the day-ahead market clearing price.
- Dispatchable resources: All dispatchable resources in SDG&E's portfolio were qualified as Resource Adequacy resources; therefore SDG&E (or Sellers' Scheduling Coordinator) had an obligation to offer these resources into the day-ahead market and could not charge

[15] This is no longer a requirement pursuant to the implementation of Convergence bidding in early 2011.

the CAISO for Residual Unit Commitment ("RUC") capacity awards. SDG&E's primary objective with respect to schedules and bids for dispatchable resources was to maintain adherence to least-cost dispatch principles. This objective was met through two strategies – bidding generation into the DAM at costs consistent with the LCD modeling, or self-scheduling resources that LCD modeling forecasted to clear the DAM economically.

While self-schedules were not mandatory, they did provide certainty to fuels traders as to the minimum natural gas quantity that resources would consume. This was particularly useful for the Sunrise plant because it has limited gas balancing rights on its pipeline. A second benefit was that self-scheduled generation quantities mitigated charges for bid-cost recovery assessed to SDG&E's load.

As noted, SDG&E submitted day-ahead generation bids that reflected actual operating costs used in LCD modeling. However, Market bidding rules imposed some constraints on this process. Supply bids have three basic components: startup cost, minimum load cost and incremental energy bids. Startup and minimum load costs used in the day-ahead market were actually created by CAISO software that relied in part on a proxy gas price comprised of published price indexes. The proxy gas price lags the actual traded gas price by one or more days, which may have caused deviations from the day-ahead LCD solution that SDG&E traders established through lock-step trading of power and natural gas. Also, bidding rules require that incremental energy bids be monotonically increasing over the range of output. This rule contradicted 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 for Palomar, Sunrise and Otay Mesa that complied with the monotonically increasing bid rule. SDG&E performs post-market assessments to confirm that these modified bid curves did not result in uneconomic day-ahead awards.

Another component of the supply bid that pertained to A/S-certified units is bids for Regulation, Spinning Reserve and Non-Spinning Reserve. As discussed in Section IV, the day-ahead market algorithm co-optimizes dispatchable capacity between generation and A/S awards; the generator is paid at least its opportunity cost of forgoing a profitable day-ahead energy sale. However, co-optimization does not consider lost energy sales in the real-time market (capacity awarded A/S for Spinning and Non-Spinning Reserves is typically not released for dispatch in the real-time market). Therefore SDG&E incorporates an estimate of expected real-time profit in A/S bid for units that typically participate in that market.

D. Hour-Ahead Least Cost Dispatch

A significant change in the Market affecting hour-ahead LCD was the creation of the HASP market at intertie points. Like the DAM, the HASP market established financially binding awards for hour-ahead self-schedules and awarded bids, but only at intertie scheduling points. The HASP market enabled SDG&E to submit cost-based bids for the Boardman import so that the day-ahead award could be economically decremented. Essentially, SDG&E would buy back the day-ahead delivery obligation if the HASP price, which can deviate significantly from the day-ahead price, dropped below SDG&E's cost. No HASP market was implemented for resources or load within the CAISO system; the CAISO published advisory HASP prices and awards for these resources and loads but they were not financially binding.

Another difference affecting hour-ahead LCD was the use of self-schedules on SDG&E's resources. Self-schedules are essentially price-taker bids submitted into the day-ahead or real-time market. The CAISO used generator self-schedules to establish a floor on the unit's dispatch awards in the real-time market. Therefore, hour-ahead self-schedules, if greater than the day-ahead award, caused the incremental portion to be a price-taker at the real-time price. This rule also applied to PIRP wind self-schedules that were submitted hour-ahead. Of note, under the Market, the CAISO does not accept hour-ahead self-schedules for load, since incremental or decremental (firm) load is a price taker in any event.

SDG&E submitted bids into the HASP market for its Boardman import to allow for the buy-back of its day-ahead award if economic. SDG&E's also self-scheduled its dispatchable generation committed in the day-ahead market at the minimum dispatch level, which enabled the CAISO to decrement the unit in response to low real-time prices. This strategy was modified as needed, for example to set a higher level of real-time dispatch to offset higher load requirement, or to mitigate excessive cycling of the units due to volatile real-time market prices.

IX. CONSTRAINTS TO LEAST COST DISPATCH

As stated in the discussion of LCD principles, SDG&E performed its least cost dispatch 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 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 be dispatched if sufficient time for startup is not available. Or, surplus energy may be sold below variable generation cost if SDG&E is long energy and has no resources that can 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. However, all SDG&E resources were 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 be committed uneconomically relative to market prices.
- Unit testing and maintenance, such as 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 least cost dispatch. As noted, Sunrise could not respond to the real-time LCD requirement because of limited gas balancing

rights on the Kern River pipeline. Another example of pipeline constraints was Operational Flow Orders ("OFOs") declared by SoCal Gas. 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. Therefore, a hindsight review will show that such units were not always dispatched according to LCD during other periods. 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.
- Market liquidity can be described as the amount of energy that can be traded at a particular price. Low market liquidity can prevent SDG&E from executing transactions to achieve anticipated least cost dispatch. Liquidity was not only a result of general market conditions such as price volatility or disinterest by the market, but also limited by counterparties that SDG&E traders were approved to trade with given authorized credit limits.

X. CONGESTION REVENUE RIGHTS

Congestion Revenue Rights ("CRRs") provide CRR holders a hedge against day-ahead congestion differentials across two price nodes, typically from a generation delivery point to a load receipt point. The CAISO determines congestion based on the Full Network Model. CRRs pay the CRR holder the positive or negative difference. The CAISO held the 2010 annual allocation and auction CRR process in September to November 2009. SDG&E participated in the auction process to obtain high value CRRs for a new resource for Q4 2010. However SDG&E did not receive a winning bid. SDG&E believes that generally, it can obtain a majority of the remaining necessary CRRs during the monthly process. SDG&E's strategy for CRRs was to nominate in the early rounds those resources in its portfolio forecast to be at higher congestion risk and shift nominations to lower congestion risk resources in the later rounds. The determination of portfolio congestion risk was made using the results from power flow analysis of the CAISO grid for 2010, performed by SDG&E Transmission Planning.

SDG&E was able to supplement CRRs awarded in the annual allocation process through the monthly CRR process. SDG&E's strategy in the monthly CRR process was much the same as the annual allocation, to nominate high congestion risk resources first followed by lesser congestion risk resources. The nomination quantity was based on the difference between expected requirements for a resource less its CRR quantity from the annual allocation. The monthly CRR process also included an auction segment, following the allocation segment. SDG&E seldom participated in the monthly auction due to the risk of incurring negative congestion charges. SDG&E did participate in the October and November monthly auctions to sell some of its surplus CRR's believed to have negative value. However the auction prices did not clear SDG&E's bid.

XI. MRTU/MARKET-RELATED COSTS

This chapter addresses costs incurred in 2010, incremental to those established in the 2008 General Rate Case ("GRC"),[16] to enable SDG&E to participate in the CAISO new Market. The implementation of the Market[17] has resulted in significantly more complex utility operations than required in the pre-MRTU CAISO structure. The CAISO introduced several core operating systems, including Scheduling Infrastructure Business Rules, CAISO Market Results Interface and an updated interface for Open Access Same-Time Information System, each requiring new and more complex data sets and interface protocols. In order to adapt its operations to meet these new requirements, SDG&E incurred capital and O&M costs totaling $2,624,478 in 2010, primarily for software-related items, contracted support, and incremental direct labor.

The MRTU Memorandum Account ("MRTUMA") was established under Commission Resolution E-4088, dated May 24, 2007, pursuant to SDG&E Advice Letter 1867-E to record and recover Commission-authorized costs that are incremental to approved items authorized under the effective GRC revenue requirements. As of December 31, 2010, SDG&E recorded a

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[16] In the 2008 GRC, SDG&E requested and was authorized 2 additional FTEs for MRTU requirements.
[17] The CAISO revised its market name from MRTU and now refers to its market simply as the Market. SDG&E uses both terms interchangeably throughout this testimony.

portion of its MRTU-related costs ($1,578,422) in the MRTUMA, as presented in Mr. Shimansky's testimony. SDG&E continues to record additional costs associated with MRTU requirements, including ongoing costs to comply with FERC-mandated enhancements, such as the Markets and Performance ("MAP") initiative, to the MRTUMA until these costs can be captured in the next GRC. The next GRC period for SDG&E begins in 2012.

The Commission reaffirmed the scope of review for the MRTUMA prescribed in Resolution E-4087 in its final decision in Pacific Gas & Electric Company's June 18 2009 ERRA Forecast proceeding (A.09-06-001). Decision 09-12-021 at page 3 states: "[T]he Commission notes that the scope of its review of PG&E's MRTU costs is not necessarily a traditional reasonableness review. The MRTU project is a project mandated by regulatory and reliability requirements of the California Independent System Operator and Federal Energy Regulatory Commission. Therefore, the Commission expects the review of these costs to primarily focus on whether the costs can be verified and are incremental."

Tables 1 and 2 summarize SDG&E's MRTU/Market-related costs in during the Record Period. SDG&E is seeking recovery for a total of $0.89 million in O&M expenses plus $1.733 million in capital costs for inclusion in rate base.

Table 1: Capital Costs

2010 MRTU/Market Capital Summary	2010
AFUDC Settlement	$ 45,522
Computer Hardware	$ 178,467
Contractor/Consultant	$ 917,805
Labor	$ 79,055
Overhead	$ 81,969
Software	$ 429,713
Grand Total	**$ 1,732,531**

The largest categories of capital costs were Software and Contractor/Consultant, which represented about 78% of total capital. The primary MRTU/Market software cost was the purchase of the Data Warehouse/Data Mart and additional enhancement upgrades provided under the GenManager product from Power Costs Inc. ("PCI"). Additional licensing support purchased from Allegro also contributed to capitalized software cost. The functionality of these software purchases are described below:

- The Data Warehouse/Data Mart implementation provides an efficient and easily accessible means to retrieve frequently relied upon procurement data. The Data Mart Proof of Concept's intent was to implement a Data Warehouse in SDG&E's current procurement software environment and deploy a selected Data Mart. Functionality is derived from the Data Warehouse Schema, Data Link, and Data Mart Builder components.
- GenManager contains the functionality to prepare complex bid files and submit them to the CAISO. It communicates with CAISO systems to validate bid status. Upgraded capabilities include support and solutions for the following areas of SDG&E's electric procurement process: Standard Capacity Product, Scarcity Pricing, Proxy Demand Response, Multi-Stage Generator, and Convergence Bidding.

Capitalized Contractor/Consultant costs were incurred for software implementation work performed by PCI and Allegro.

- The PCI GenManager and Data Warehouse products are used in several markets across the United States and needed to be customized to meet SDG&E and CAISO requirements. PCI performed much of this work including modeling and configuring each of SDG&E's resources, ensuring that all bid and schedule calculations complied with market rules, designing/creating user interfaces and testing CAISO communication protocols. Additional costs were incurred to adapt to CAISO's frequent requirements modifications during the Market simulation phases.
- The Allegro amount reflects work performed by the vendor to specify, design, deliver and test the software.

Other categories of MRTU/Market-related capitalized costs are described below:

- Capitalized Labor costs reflect IT work in the following areas: definition of MRTU/ Market business process and systems requirements, assessment and selection of vendors and products, development and integration of systems (for example, building an interface between PCI and Allegro to transfer transaction data), and product testing.
- Overhead costs reflect applicable labor and non-labor overheads to the costs charged as capital.

- Computer Hardware costs were incurred to procure and implement application servers used to host MRTU/Market application software in production, QA, and Disaster Recovery environments.
- Allowance for Funds Used During Construction ("AFUDC") represents the cost of borrowing funds until a project is placed into operation.

Table 2: O&M Expenses

2010 MRTU/Market O&M Summary		2010
Contractor/Consultant	$	435,687
Employee Travel	$	14,248
Labor	$	285,901
Other	$	2,627
Overhead	$	66,424
Software	$	87,060
Grand Total	**$**	**891,947**

The largest categories of O&M expenses were Contractor/Consultant and Labor. These represented about 81% of total O&M costs and are described below:

- PCI performed post-installation work and continued software support in the following areas: bid strategy implementation, installation and setup of Bid Evaluator module, configuration of resources (e.g., new resources, refinement to existing configurations, application to Outage Management module), automation of certain workflows, creation of customized dashboards (user interfaces), response to MRTU/Market enhancements, including hour-ahead ancillary services and Proxy Demand Resource.
- Allegro performed post-installation work to customize their software to meet SDG&E-specific requirements related to data table configuration and communication with PCI and CAISO interfaces.
- Business Development Strategies performed quantitative analysis of market data and SDG&E's portfolio and recommended alternative bidding strategies.
- Customized Energy Solutions ("CES") performed detailed analysis of CAISO MRTU/Market settlement statements to validate revenues and charges.
- Czarnecki-Yester Consulting Group ("CYCG") provided support for SDGE's procurement settlement business process performance. Through the ISOSettlePro

support package, CYCG provided a full function CAISO settlement system producing soon after trade date CAISO predictive settlements, shadow settlements, settlement statement validations, reconciliation, allocations, reporting, and down-stream system integration.

- Software costs primarily reflect annual license fees and maintenance costs paid to Allegro and PCI for software upgrades and product support from the software vendors. These charges began to accrue once the software products were delivered and placed into production in 2009.
- Labor costs reflect 4 FTEs who performed the following MRTU/Market-related work:
    - Project management, resource coordination
    - Participation in CAISO stakeholder processes
    - PCI configuration and acceptance testing
    - Training and procedures development
    - Market simulation
    - Strategy development
    - CRR valuation, strategy, bidding, portfolio management
    - Market data analysis, report generation
    - Settlement support, predictive reports
    - Scheduling support
    - Integration of new initiatives (e.g., MAP)

Other categories of MRTU/Market-related O&M expenses are described below:

- Overhead costs reflect applicable labor and non-labor overheads to the costs charged as O&M.
- Employee Travel costs primarily reflects travel costs to/from the CAISO offices by various SDG&E personnel in 2010 to participate in MRTU/Market workshops, implementation / market simulation meetings.

XII. CONCLUSION

SDG&E described its plans for serving load from its fully integrated portfolio of utility-owned resources, power purchase contracts, allocated DWR contracts and market transactions in the Commission-approved LTPP in effect for the Record Period. SDG&E managed the operational, dispatch and administrative functions of the allocated DWR contracts and prudently dispatched those contracts, along with its resources from its own portfolio, in a least cost manner during the Record Period. SDG&E consistently followed the Commission's directive to make dispatch decisions based on variable costs. As a result, all costs recorded to SDG&E's 2010 ERRA should be fully eligible for cost recovery through rates.

SDG&E also requests the Commission find all MRTU/Market-related costs, in the amount of $2,624,478, in compliance with SDG&E's approved MRTUMA tariff and grant the authority to transfer the December 31, 2010 balance in the MRTUMA of $1,578,422 to the NGBA for future recovery in SDG&E's electric commodity rates in accordance with the approved disposition of the account.

This concludes my prepared direct testimony.

XIII. QUALIFICATIONS OF ANDREW SCATES

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 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.

APPENDIX 1

(Forced Outages and Derates of 24 hours or greater)

Palomar Forced Outages and Derates				
Start Date	**StartTime**	**End Date**	**End Time**	**Reason for Outage**
08/05/2010	1430	08/08/2010	1155	Lost steam turbine due to Control Valve #1 Oil leak
12/22/2010	1215	03/25/2011	559	Tripped due to Step up Transformer

Miramar 1 Forced Outages and Derates				
Start Date	**StartTime**	**End Date**	**End Time**	**Reason for Outage**
02/05/2010	710	02/06/2010	1120	maintenance work scheduled

Miramar 2 Forced Outages and Derates				
Start Date	**StartTime**	**End Date**	**End Time**	**Reason for Outage**
03/12/2010	740	03/20/2010	10:00	Transformer Blew
06/05/2010	2040	06/09/2010	1545	High Temps issues on Crank
09/16/2010	1610	09/17/2010	1816	Gas Compressor failure limiting to 36MW

BEFORE THE PUBLIC UTILITIES
COMMISSION OF THE STATE OF CALIFORNIA

DECLARATION
OF ANDREW SCATES

A.11-06-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 2010, (ii) Costs Related to those Activities Recorded to the Energy Resource Recovery Account and Transition Cost Balancing Account in 2010 and (iii) Costs Recorded in Related Regulatory Accounts in 2010

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, 2010 through December 31, 2010, 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 confidential 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**
AS-10 line 13	I.B.2	Covers actual quantity of procured natural gas transportation. Confidential for one year.

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 type of data that is provided herewith.

[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.

6. The Protected Information cannot be provided in a form that is aggregated, partially redacted, or summarized and continue to provide the level of support to the Application as intended; however SDG&E is certainly willing to work with the Commission regarding possible aggregations if the Commission seeks to make any of the confidential information provided in the Testimony public.

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

Executed this 31st day of May, 2011, at San Diego, California.

Andrew Scates
Market Operations Manager
San Diego Gas & Electric Company