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Witness: Tony Choi
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SAN DIEGO GAS & ELECTRIC COMPANY

PREPARED DIRECT TESTIMONY OF

TONY CHOI

PUBLIC VERSION

BEFORE THE PUBLIC UTILITIES COMMISSION
OF THE STATE OF CALIFORNIA

May 20, 2008

#231227

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ON BEHALF OF SDG&E

I. INTRODUCTION

This testimony discusses how San Diego Gas & Electric Company (SDG&E) complied between January 1 through December 31, 2008 (the record period) with Commission direction to dispatch its portfolio of supply resources, including Utility Retained/Owned Generation (URG), power purchase contracts and allocated Department of Water Resources (DWR) contracts, in a least cost manner. In implementing the relevant SDG&E Long Term Procurement Plan (LTPP)[1], SDG&E fully integrated into a single combined portfolio its existing generation and power purchase contracts with its allocated DWR contracts. In this testimony, SDG&E presents an overview of Commission guidance on least cost dispatch and then describes the least cost dispatch process implemented by SDG&E which, among other things, evaluates the resources in its common portfolio against market purchase and sale opportunities.

SDG&E has filed four quarterly advice letters (AL 1987-E, AL 2013-E, AL 2038-E, and AL 2062-E for Q1 through Q4 2008, respectively) covering the record period as required by the Master Data Request which was part of Decision D.02-10-062. These quarterly advice letters provide detailed descriptions of the transactions that resulted from SDG&E conducting its least

[1] This testimony describes the various energy resources in SDG&E's electricity portfolio and addresses the manner in which SDG&E complied during the Record Period with its obligation to dispatch its energy portfolio in a least cost manner consistent with the relevant Commission-approved LTPP. For purposes of the Commission's review and the compliance findings requested herein, the relevant Long-Term Procurement Plan (LTPP) is SDG&E's 2006 LTPP, which was approved in D.07-12-052. Note that a conformed version of SDG&E's 2006 LTPP (conforming to modifications ordered in D.07-12-052) was filed as part of Advice Letter 1983-E, which was approved in Resolution E-4189.

cost dispatching responsibilities, as well as other information (such as system conditions, loads, resources and generation gas transactions pertinent to SDG&E's least cost dispatch for the record period). Some of the transactions described in the quarterly advice letters are integral to least cost dispatch, but the expenses of those transactions (such as DWR contract expenses) are not recorded in SDG&E's Electric Resource Recovery Account (ERRA).

All of the transactions presented here for recovery were executed in compliance with the approved, relevant LTPP, including the requirement to conduct least cost dispatch, and are therefore eligible for full cost recovery through the ERRA and rates.

II. COMMISSION DIRECTION FOR LEAST COST DISPATCH

In D.02-09-053, which allocated the DWR contracts to the three California investor owned utilities (IOU), the Commission charged the IOUs with the responsibility to "assume all the operational, dispatch and administrative functions"[2] 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."[3] In this decision, the Commission also provided direction on how a utility should implement least cost dispatch of the combined utility/DWR portfolio. D.02-09-053 states that: "economic 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."[4]

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[2] D.02-09-053, Ordering Paragraph 2.
[3] D.02-09-053, Ordering Paragraph 5.
[4] D.02-09-053, p. 30-31.

The requirement for utility least cost dispatch 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 included standards of conduct for utility behavior to be followed as the utilities took on the responsibility for electric procurement for their bundled customers and the operational administration of the allocated DWR contracts. Standard of Conduct # 4 (SOC-4) adopted in that decision states that "[t]he utilities shall prudently administer all contracts and generation resources and dispatch the energy in a least-cost manner."[5] In two subsequent decisions following the issuance of SOC-4, the Commission offered further guidance on the definition of least cost dispatch, including that it was "least cost" from the prospective of a utility's ratepayers, by adopting the following language as a definition of prudent contract management and least cost dispatch:

> 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 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.[6]

Further Commission guidance was provided in July 2004, in response to a California Independent System Operator (CAISO) letter to the Commission requesting assistance from the utilities in the management of intrazonal congestion. The Commission issued an Assigned Commissioner Ruling (ACR) in R.04-04-003 proposing that the utilities alter their procurement and scheduling practices as part of least cost dispatch to reduce intrazonal congestion to help

[5] D.02-10-062, p. 51 and Conclusion of Law 11, p. 72.
[6] D.03-06-076 at p. 23.

mitigate the CAISO's concerns over reliability. The ACR was followed by D.04-07-028, urging that the IOUs take immediate action to assess the potential for intrazonal congestion when procuring and scheduling resources. SDG&E responded to this decision by including an additional cost adder, further described in Section V.6, to its least cost dispatch process to reflect the potential costs of intrazonal congestion with certain procurement options. In response to D.04-07-028, SDG&E filed with the Commission, on December 3, 2004, Advice Letter 1641-E, describing its revised procurement procedure incorporating the new cost adder to account for anticipated intrazonal congestion costs.

Finally, with regard to review of least cost dispatch transactions in ERRA proceedings, the Commission determined in the 2004 Southern California Edison (SCE) ERRA review in D.05-01-054 that the scope of least cost dispatch review should include the dispatch of resources under SCE control in the day-ahead, hour-ahead and real-time markets. The Commission reiterated this scope of review for least cost dispatch in D.05-04-036, regarding Pacific Gas & Electric Company's (PG&E) ERRA review.

III. PRINCIPLES OF LEAST COST DISPATCH

SDG&E has adopted the following guiding principles for least cost dispatch of its combined SDG&E/DWR portfolio:

- SDG&E shall provide to its customers energy and ancillary service requirements at a reasonable total cost, consistent with competitive market conditions.
- SDG&E shall integrate SDG&E and DWR resources into a joint portfolio that is dispatched based upon variable cost economics (subject to market constraints) and without preference to utility resources.

IV. SDG&E PORTFOLIO OVERVIEW

In the CPUC approved LTPP in effect for the record period, SDG&E has detailed its plans for serving load from its fully integrated portfolio of URG, power purchase contracts, allocated DWR contracts and market transactions. For the record period, most of the energy requirements were met with SDG&E-contracted must-take[7] supplies, purchase power agreement resources and utility-owned generation. The DWR allocated contracts[8] also included must-take supplies and dispatchable resources. SDG&E also imported energy, primarily from its power purchase contract with Portland General Electric's (PGE's) Boardman plant[9] and out-of-state Qualifying Facility (QF) contract with Yuma Cogeneration Association (YCA). Although the Boardman contract is dispatchable, its variable generation cost was low enough that it was almost always fully scheduled. SDG&E also has some limited dispatchability in the form of economic curtailment of certain QF contracts described later in this testimony.

For the record period, the most significant changes to the SDG&E/DWR portfolio were the expiration of the J.P. Morgan contract A (200 MW of 7x24 must-take energy) and reduction of the J.P. Morgan contract B (from 450 MW to 275 MW of 6x16 must-take energy). SDG&E was able to fully cover its projected load, including the summer peak hours, with the resources from the combined SDG&E/DWR portfolio and incremental monthly market energy purchases for the month of August. Almost all of the market transactions SDG&E made in the record period (except for limited operations-related purchases described later in this testimony) were

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[7] SDG&E must take supplies include its 20% share in the output of San Onofre Nuclear Generating Station (SONGS), QF power purchase contracts and renewable resource power purchase contracts.
[8] The allocated DWR contracts for the record period include Cabazon (as available wind), Whitewater Hill (as available wind), Sunrise (dispatchable) and CalPeak in SP15 (dispatchable).
[9] The PGE contract gives SDG&E rights to 15% of the output of the Boardman coal-fired power plant located in Oregon. The contract is dispatchable on 30 minutes notice before the hour. The variable cost of the contract is based on coal prices [redacted] during the record period.

based on economic savings relative to its resource supply portfolio. Market purchases displaced the dispatchable generation in SDG&E's portfolio if the price was lower than variable generation costs.

The LTPP also addressed SDG&E's function of procuring, as DWR's limited agent, natural gas supplies to support the tolling requirements of the allocated DWR dispatchable contracts.

V. SDG&E IMPLEMENTATION OF LEAST COST DISPATCH

SDG&E implementation of least cost dispatch is comprised of several steps and begins with a year-ahead dispatch forecast of its supply portfolio by the Resource Planning department (as described in SDG&E's approved LTPP). The second step is a short-term forecast performed a week in advance by the Electric & Gas Procurement department. In the final step, trading and scheduling personnel create least cost dispatch spreadsheets to assist in the execution of least cost dispatch decisions in the day-ahead and hour-ahead markets.

The year-ahead least-cost dispatch forecast was produced using a production cost model[10] of the combined SDG&E/DWR portfolio for the record period given assumptions for load, generation availability and market prices. The model results provide a framework for the expected utilization of resources for the coming year, including quantities of dispatchable generation by resource, fuel requirements, volume of market transactions and a baseline estimate of costs SDG&E uses to measure performance against the Commission adopted Customer Risk Tolerance (CRT)[11] and probability of reaching an ERRA rate trigger.

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[10] SDG&E uses the PROSYM production cost model from Ventyx/Global Energy Decisions for long-term modeling..

[11] The Commission described CRT and its use in Decisions 02-10-062, 02-12-074, 03-12-062 and 07-12-052.

During the record period, the short-term forecast, referred to as a weekly forecast, is based on a production cost model to create the weekly plan that calculates a least cost dispatch solution for the following 12-day horizon[12]. The model is updated with market prices, load forecast, resource availability, new term transactions and other factors that can impact resource dispatch. The model output is reviewed by several sections within the Electric & Gas Procurement department, including Energy Supply & Dispatch, Energy Risk Management and Settlements & Systems, to ensure that results are consistent with least cost dispatch standards. This review occurs for the forward-looking weekly forecast as well as for the past week's forecast to identify differences between the model results and actual operations, and to continually seek ways to improve the forecasted result compared to actual. Typical factors reviewed include load forecast differences, characteristics of generation resources, changes to planned resource availability and modeling of market prices.

For daily dispatch decisions, SDG&E uses Excel spreadsheets customized for the day-ahead or hour-ahead market. The starting point for the day-ahead spreadsheet is the output of resource commitments and loading from the weekly model run for the operating day. Incremental refinements are made to the hourly dispatch from the weekly production cost model run for the operating day. The weekly model run may be updated any time during the week, if any significant system or resource changes occur. For dispatch decisions made in the day-ahead market, the spreadsheet contains the most recent forecast of load and must-take supplies as well as available dispatchable resources with their heat rates. With the input of indicative gas and

[12] SDG&E used OPSYM, a derivative of the PROSYM model, for shorter term modeling until February 2008. In February 2008, SDG&E transitioned from OPSYM to GenTrader, a model produced by Power Costs Inc. that SDG&E acquired in preparation for modeling its portfolio under MRTU. These models performed calculations using all available resources in the portfolio to determine the least-cost dispatch and unit commitment solution over the study period.

electric prices for next day delivery, the spreadsheet determines SDG&E's net short position for each hour and the variable cost for each dispatchable resource. From the spreadsheet, the day-ahead traders have sufficient information to make the least cost dispatch determination for each hour, choosing between dispatchable generating resources and market transactions. The completed day-ahead dispatch spreadsheet is then used for sending dispatch notices to resources and copying dispatched quantities into SDG&E's scheduling system[13], which tracks all resource and load schedules. SDG&E submits day-ahead schedules for load and schedules for supply by 10 a.m. each day to the CAISO. These day-ahead schedules also include adjustment bids, described in the next chapter, which protected SDG&E schedules against congestion charges. When day-ahead congestion management is completed, the CAISO publishes final day-ahead schedules, which are retrieved from the CAISO by the ACES scheduling system.

Once day-ahead schedules have been finalized by the CAISO, a second similar spreadsheet is used by SDG&E's Real Time Desk (staffed around the clock) to determine the least cost solution for balancing SDG&E's net position in the hour-ahead market. The spreadsheet takes input from the load forecasting model and scheduling system to determine the most up-to-date supply position, long or short, coming into each hour. Based on the cost of delivered gas, heat rate and load point for each dispatchable resource, the spreadsheet will indicate the incremental (or decremental) cost of changing the output of any dispatchable resource. The Real Time Desk will compare hour-ahead market prices with dispatchable resource costs to determine the least cost solution for balancing load in the hour-ahead market.

[13] SDG&E uses the ACES scheduling system from Sungard Energy Systems. The system was originally developed by ALTRA Power Systems, which was acquired by Caminus, which was later acquired by Sungard.

VI. ELEMENTS OF LEAST COST DISPATCH

Least cost dispatch is achieved through a sequence of decisions based on several key inputs and processes that are described in this section.

1. Load Forecasting

The first step of least cost dispatch is forecasting the load requirement for SDG&E bundled customer load. The forecast for total SDG&E system load is first developed, then adjusted down to account for transmission losses and direct access load to arrive at the SDG&E bundled load forecast. Forecasting is performed along several time frames, starting with an annual long term forecast developed by SDG&E's Market Planning and Analysis section for resource planning purposes. These forecasts typically span several years and are also used for regulatory proceedings and internal planning. Load forecasts are also developed week ahead, day-ahead and hour-ahead in advance of the actual operating hour. These short-term forecasts are made within SDG&E's Electric & Gas Procurement department and establish load requirements used in the least cost dispatch of SDG&E's resource portfolio.

The short-term bundled load forecast is produced using an Excel-based software application that combines the three components noted above: SDG&E system load forecast, direct access load forecast and calculated system transmission losses.

SDG&E system load is forecasted using a commercially available, neural network software application.[14] This application analyzes relationships between historical system load and weather data, and develops a 12-day profile of future loads using forecasts of temperature and humidity. The program is updated daily and hourly as actual load data becomes available

[14] The load forecasting software is called AANNSTLF (short for Advanced Artificial Neural-Network Short-Term Load Forecaster). The software vendor is Pattern Recognition Technologies, Inc.

and updated temperature and humidity forecasts are developed by SDG&E's weather service provider. SDG&E monitors the performance of its forecasting application on an hourly basis and may make corrective adjustments to its results, if warranted, to account for changing load patterns.

The direct access load forecast is a 7-day forecast provided twice a week by SDG&E's Market Planning and Analysis section. It is based on the current direct access accounts in the SDG&E billing system and the historic load for those accounts. System transmission losses are calculated as a percentage estimate of the system load forecast based on historical data.

For a given delivery day, the short-term bundled load forecast is first made a week in advance as an input to SDG&E's short-term least cost dispatch model. The model output provides SDG&E with a general direction of how its supply portfolio could be optimally dispatched to meet the forecasted load. The bundled load forecast is then updated on the pre-scheduling day prior to the delivery day. This forecast is used to make day-ahead least cost dispatch decisions, including unit commitments and market transactions.

Finally, an intra-day forecast is updated regularly throughout the delivery day to capture actual load and weather conditions. The updated forecast is used to determine whether the existing energy schedules are in balance, surplus or deficit, compared to expected load requirements. This information then allows the Real Time Desk to make incremental least cost dispatch decisions to balance supply with load.

2. Must-Take Supply Forecast

A significant portion of SDG&E's portfolio is made up of must-take generation and energy schedules. From a least cost dispatch perspective, must-take supplies have a zero variable cost and are included in the daily resource mix before any dispatchable resource or market transaction decisions are made. Must-take supplies include SDG&E's share of SONGS output, SDG&E QF and renewable contracts, DWR firm bilateral contracts, DWR wind contracts and any previously contracted term market purchases. An availability forecast is made for each must-take supply resource and individually entered into SDG&E's scheduling system. The must-take supply forecast can then be extracted from the scheduling system and used as input for the weekly plan and the day-ahead least cost dispatch process. The forecast of must-take supplies is subtracted from the forecast of bundled load requirements to determine the quantity of supply to be filled through either dispatchable resources or market purchases.

SDG&E receives weekly, and in some cases daily, forecasts of hourly deliveries from the must-take facility owners. When no facility owner supply forecast is provided, which is typical for smaller QFs, SDG&E generates its own forecast of supply based on historical deliveries. This forecast includes any scheduled outages or derating for these facilities and economic curtailments available to SDG&E for two of its QF contracts.

For any firm bilateral contracts, the energy quantities, hours of delivery and delivery points are set by the terms of the contracts, so quantities need only be entered into the scheduling system once. If market transactions span more than one day (as is typical for weekend trading), the transaction quantities for the second and any subsequent days are considered as must-take supplies in the same manner as long term firm bilateral contracts.

The SDG&E and DWR wind contracts are also treated as must-take supplies. All wind resources in the SDG&E/DWR portfolio participate in the CAISO Participating Intermittent Resource Program (PIRP), which provides day-ahead and hour-ahead forecasts of resource output. By scheduling the ISO-provided forecasts of wind resource output, PIRP resources can defer imbalance energy settlement to a single month-end aggregate value and avoid uninstructed deviation penalties. The CAISO issues day-ahead wind forecasts at 5:30 a.m. so they can be included as part of the must-take supply forecast, and subsequent hour-ahead wind forecasts are used to update final hour-ahead wind schedules. The PIRP hour-ahead forecasts also include a rolling six hour look-ahead forecast of resource output that provides the Real Time Desk with a forecast of the change in available wind energy between the day-ahead and hour-ahead forecasts. The uncertainty of wind forecasting is such that large swings in net position can occur due to the deviations between day-ahead and hour-ahead forecasts, which must be resolved by the Real Time Desk, sometimes on a short lead time.

SDG&E's long term power purchase contract with PGE is technically a dispatchable contract. However the variable cost of the contract (based on coal prices) is typically well below the cost of other dispatchable contracts or market prices, thus its dispatch is usually equivalent to that of a must-take contract. However, because the contract energy is delivered at a frequently constrained import point (California-Oregon Border or COB), it is subject to congestion. SDG&E hedges against potential congestion costs with adjustment bids or locational swaps, both of which are discussed later in this section.

Another form of must-take energy is CAISO-issued RMR dispatches. When issued, South Bay (an RMR-contracted resource) must generate and schedule energy in the day-ahead or hour-ahead market. SDG&E had the option to schedule the generation against its load (when economic) or to an RMR load point. When RMR energy is scheduled against load, it becomes must-take energy. When RMR energy is scheduled to the RMR load point, dispatch costs are fully recovered through imbalance energy revenues and the RMR contract (paid by the local Transmission Owner, in this case SDG&E Transmission).

3. Day-Ahead Dispatch

Least cost dispatch decisions are made prior to the delivery day, in time to schedule in the CAISO day-ahead market. A pre-configured Excel spreadsheet is populated with the day-ahead load forecast and must-take energy schedules for delivery dates corresponding to the pre-scheduling calendar published by the Western Electricity Coordinating Council (WECC). The difference between the load requirement forecast and must-take supplies represents the open position, which must be satisfied by the least cost combination of dispatchable contracts and market purchases. The weekly least cost model provides a preliminary guideline to resolving the complex analysis needed for unit commitment. However, the day-ahead least cost dispatch solution is determined using the latest load forecast, must-take schedules, market prices and generation cost available on a day-ahead basis.

Market energy prices are a key input into the dispatch spreadsheet. As trading activity begins each morning, market price quotes from brokers and on-line exchanges (e.g. Intercontinental Exchange or ICE) for gas and power products are entered into the dispatch spreadsheet. A profile of hourly prices based on historical data is used to transform market prices for block peak and off-peak energy products into a price for each hour. Using the heat rates and gas prices for dispatchable units, the variable cost of each resource is displayed along with the corresponding power market price. Day-ahead traders thus have access to the latest variable cost and open position information necessary to improve upon the week-ahead modeled dispatch of generation and market purchases.

The spreadsheet application also produces the ancillary services requirement corresponding to the bundled load forecast. As resources capable of providing ancillary services are dispatched to serve load, the spreadsheet application determines which ancillary services can be self-provided or bid into the ancillary services market.

An after-the-fact review of a particular day's dispatch spreadsheet does not fully illustrate the fluid nature of least cost dispatch. The final day-ahead solution is a result of market prices (for generation dispatch or market transactions) that move throughout the least cost dispatch process. Because SDG&E seeks to optimize between generation dispatch and trading, price changes between the gas and power markets often affect the proportion of load requirements served by each type of resource.

A key resource in SDG&E's portfolio that demonstrates the dynamic nature of least cost dispatch decision-making is the DWR PPA for the Sunrise power plant, located in ZP26. This contract was allocated to SDG&E along with capacity rights on the Kern River pipeline, which can be used to deliver natural gas to the Sunrise plant or sold into higher-priced gas markets when gas price spreads are favorable. The relationships between the value of Kern River pipeline capacity, the Sunrise generation cost and the Path 26 Firm Transmission Rights (FTR) capacity used to deliver power from Sunrise to SDG&E's load presents a complex optimization challenge. The pipeline capacity / power plant / FTR chain of assets essentially enables SDG&E to convert low-cost Rockies gas to SP15-delivered power. However, least cost dispatch requires that the use of each asset be continuously optimized across its market alternatives and not passively operated to convert Rockies gas to SP15 power. The table below illustrates various least cost dispatch scenarios that may result depending on the relative differences between market energy prices at different delivery points from the gas supply basin to SP15.

Confidential/privileged pursuant to applicable provisions of D.06-06-066, G.O. 66-C and PUC Code Section 583 and Section 454.5 (g).

Scenario	Opal Gas Price	Wheeler Ridge Gas Price	Sunrise Generation Cost	ZP26 Price	SP15 Price	Optimal Use of Assets
1 – Base Case						
2 – Strand FTR Capacity						
3 – Strand Sunrise Capacity						
4 – Strand FTR and Sunrise Capacity						
5 – Strand Kern River Capacity						
6 – Strand Kern River and FTR Capacity						
7 – Strand Kern River and Sunrise Capacity						
8 – Strand Kern River, Sunrise and FTR Capacity						

When day-ahead least cost dispatch is completed, the Pre-schedule Desk issues dispatch notices to generation operators and submits day-ahead trades and schedules to the CAISO.

During the record year, SDG&E complied with CAISO Amendment No. 72, which went into effect November 17, 2005. Amendment 72 requires SDG&E to schedule a minimum of 95% of forecasted load on a day-ahead basis during on-peak hours and a minimum of 75% of forecasted load on a day-ahead basis during off-peak hours. The amendment also requires SDG&E to report, on a weekly basis, forecast vs. schedule hour load schedules to the FERC.

4. Real Time Dispatch

After the CAISO day-ahead market closes (about 2 p.m. the afternoon prior to the delivery day), SDG&E creates a second dispatch spreadsheet that is populated with final CAISO day-ahead energy and ancillary services schedules to establish the starting point for *hour-ahead* least cost dispatch. Hour-ahead least cost dispatch, for each hour of the delivery day, is necessary to adjust for both operational and market price changes that occurred after the day-ahead market. Updates to the load forecast, market prices and generator availability are entered into the hour-ahead dispatch spreadsheet.

These updates enable the hour-ahead dispatch spreadsheet to calculate the net long or short position relative to forecast load requirements for each hour. In addition, the Real Time Desk surveys counterparties, brokers and ICE to determine availability and price for hour-ahead market energy. SDG&E is then able to perform a final hour-ahead least cost dispatch optimization of its resources to meet load obligations and energy sales.

5. Fuel Management

The DWR Sunrise and Calpeak PPAs are tolling agreements under which fuel for the underlying contract resources may be supplied by either the resource owner or DWR. Exhibit B of the SDG&E Operating Agreement with DWR describes the specific responsibilities of the resource owner, SDG&E and DWR, as they relate to managing the fuel for these contracts. While DWR retains legal and financial responsibility for fuel and related services, SDG&E acts as DWR's limited agent for fuel procurement and management activities. During the record period, SDG&E continued to perform in the Fuel Supplier and Fuel Manager roles for the

Sunrise contract and the Fuel Supplier role for the Calpeak contracts. The costs of fuel for the DWR tolling contracts, while an important part of a least cost dispatch decision-making process, is not recovered by SDG&E through the ERRA but rather by DWR through its retail remittance rate.

During the record year, SDG&E also acted as Fuel Manager and Fuel Supplier for resources in its own portfolio: Palomar Energy Center, Miramar Energy Facility, South Bay Power Plant and Encina Power Plant. Fuel costs for these resources are recovered in ERRA as described in Section II of Ms. Garcia's testimony.

6. Congestion Charges

Congestion charges can have a significant impact on least cost dispatch. Least cost decisions for resource dispatch or market purchases that are economic before any congestion costs are known can be rendered uneconomic once congestion charges in day-ahead or hour-ahead market are included. SDG&E submits adjustment bids to provide the CAISO a means for modifying intertie and interzonal schedules to preserve least cost dispatch economics (SDG&E also adopted an intrazonal congestion dispatch protocol in response to D.04-07-028, which is described later in this section).

An adjustment bid establishes the maximum congestion charge that SDG&E is willing to pay to schedule energy across a congested transmission path. If the congestion charge, as determined by the CAISO congestion management process, exceeds SDG&E's adjustment bid, the CAISO will reduce the SDG&E supply schedule across the congested path, thereby reducing the energy schedule for resources (including the load schedule) on both sides of the congestion. When adjustment bids are exercised in the day-ahead market, any supply schedule cuts can be replaced in the hour-ahead market. When adjustment bids are exercised in the hour-ahead market, the cut supply cannot be replaced with another energy schedule and any resulting net short will carry over to the CAISO imbalance market.

SDG&E's practice is to place adjustment bids only on schedules at CAISO interchange points, since these points are a primary source of congestion, and adjustment bids on a northern interchange point will also protect that schedule against congestion on Paths 15 and 26. Adjustment bids are structured to cut the intertie schedules to 0 MW if the usage charge on the intertie or on any intervening path reaches SDG&E's adjustment bid price. Adjustment bid prices are based on expected price spreads for replacement energy at uncongested locations. If supply schedules are cut as the result of day-ahead market congestion, SDG&E's Real Time Desk determines the least cost source of replacement energy, using either a dispatchable contract or a market purchase.

An alternative method to adjustment bids for congestion mitigation is use of locational swaps to avoid flowing energy on a potentially congested path. A congestion risk mitigation locational swap involves selling the energy on the upstream side of the congested path and purchasing the same volume of energy closer to the load. These transactions avoid using a potentially congested path and retain the original supply volume to serve load. While these transactions may involve some net cost to SDG&E if the purchase price exceeds the sales price, they are only done if the spread between purchase and sale price exceeds the potential congestion cost exposure. Locational swaps can also be used to avoid normal CAISO costs, such as transmission losses and grid management charges, that are imposed on imports scheduled at interchange points even when no congestion is expected. Swap transactions are discussed in more detail later in this testimony and are also discussed in SDG&E's Quarterly Advice Letter filings.

With the Commission ruling in July 2004 (D.04-07-028) that utilities should include schedule deliverability and local reliability in least cost procurement decisions, SDG&E initially avoided procurement and scheduling transactions with the potential to create intrazonal congestion, which the CAISO was having difficulty managing. As more data became available on the CAISO's costs for managing intrazonal congestion, SDG&E developed a procedure for determining a cost adder for transactions that could increase the potential for intrazonal congestion and a credit for generation dispatch that could reduce the potential for intrazonal congestion. These cost adders and credits are updated weekly based on data published on the CAISO OASIS website and are incorporated into the least cost dispatch process, much like interzonal congestion costs. The details of SDG&E's procedure to address intrazonal congestion costs was filed with the Commission on December 3, 2004 in AL 1641-E; this protocol was in effect throughout the record period.

7. Firm Transmission Rights

SDG&E again participated in the CAISO's Firm Transmission Rights[15] (FTRs) auction to secure hedges against interzonal congestion across certain paths. Awarded FTRs had an effective term of one year, running from April 1, 2008 through March 31, 2009.

SDG&E's primary need was for Path 26 FTRs to hedge deliveries from the allocated DWR Sunrise PPA. This contract is based on the combined cycle plant with a nominal output of 560 MW and located in ZP26, north of the SP26 zone in which SDG&E's load resides. To serve SDG&E load, energy from the Sunrise plant must be scheduled across Path 26, which may

[15] An FTR provides a financial hedge against congestion charges by providing the holder with a share of congestion revenues equal to the product of the FTR quantity and usage charge. An FTR also provides physical delivery priority on the path being scheduled.

experience significant congestion. For the record period, SDG&E acquired 560 MWs of Path 26 FTR capacity in the auction to hedge Sunrise schedules.

SDG&E also acquired an additional 85 MW of Path 26 FTRs in the auction for June through September 2008 to hedge Path 26 schedules for Boardman deliveries during the summer load period, and 59 MW and 64 MW of FTRs across the California-Oregon border for November and December respectively to hedge Boardman imports.

8. Economic QF Curtailment

Two QF contracts, YCA and Goal Line, give SDG&E limited curtailment rights when market prices are lower than the contract price for energy. Curtailment does not require these units to shut down; the QFs elect to either run and be paid the actual market price or shut down for the curtailment period. SDG&E includes these curtailment provisions in its least cost dispatch and regularly monitors the difference between the market and contract prices to determine when maximum economic value can be obtained through QF curtailment.

The Goal Line QF contract allows 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 is lower than the QF energy price for those hours, SDG&E provides Goal Line with a daily curtailment notice, which includes a curtail price. For the record period, SDG&E issued a curtailment notice to the Goal Line QF every day that was allowed by the contract.

The YCA QF contract provides for two types of economic curtailment: flexible and block. Flexible curtailments are limited to 1,400 hours per year with a minimum of 8 hours per curtailment. The block curtailments are two 200 hour blocks per year. Since these curtailments have limitations of exercise, SDG&E forecasts market and contract prices to determine when the differential between these prices are the greatest, thereby producing the greatest cost savings. SDG&E updates 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 1,400 hours of its flexible curtailment hours during off-peak and shoulder month hours, and both 200 hour block curtailments in April 2008.

9. Must-Offer Waiver

The CAISO Tariff requires that generators that are registered as Resource Adequacy resources offer any available capacity not already scheduled for dispatch through a provision called the "must offer obligation" (MOO). Generators may request a waiver from this obligation in order to avoid operating uneconomically to provide this MOO capacity. The deadline to submit MOO waiver requests is 11 a.m. one day-ahead of delivery, which provides the CAISO enough lead time to commit long-start units for the following day. If the day-ahead least cost dispatch process does not show a need for a dispatchable resource, SDG&E will submit a must offer waiver request from the CAISO and shut the resource down if the request is granted. If the CAISO denies the waiver request, the generator must remain online at minimum load and the CAISO will pay the generator its minimum load carrying costs. Once a generator has shut down on a granted must offer waiver, the CAISO may rescind the waiver at a later date if it anticipates the need for the capacity from an off-line unit. On a rescinded waiver, the CAISO will pay the costs for the generator to start up and operate at minimum load.

All of SDG&E's dispatchable resources are subject to dispatch by the CAISO through the must-offer obligation. Under a MOO dispatch, the resource will continue to remain in operation but will not be part of SDG&E's schedule. The generation is instead delivered into the CAISO imbalance market. SDG&E, however, does have the option to schedule energy from the must offer resource to serve its load and assume the operating cost responsibility of the resource. SDG&E schedules energy or ancillary services from a MOO dispatch resource if it is SDG&E's

least cost dispatch option When the resource is no longer scheduled against SDG&E load in the hour-ahead market, it returns to operation under a denied must offer waiver status.

The Calpeak dispatchable DWR contract is subject to the must offer obligation, but the terms of that DWR contract specify that the plant's scheduling coordinator takes responsibility to meet the CAISO must offer requirements.

The Sunrise plant under contract with the DWR has been granted an exemption from the must-offer obligation in the real-time market because of the relatively stringent gas balancing limits on the Kern River pipeline that serves the plant. These limits do not allow the plant's gas usage to deviate significantly from its scheduled quantities, which would be a likely outcome due to must offer obligation dispatches that cannot be anticipated (and scheduled) by SDG&E.

Palomar Energy Center is required to comply with must offer obligation, but is not required to request a must offer waiver because it can be brought online within 90 minutes. The CAISO receives timely information through the hour-ahead schedules to determine whether a MOO dispatch is required for Palomar since hour-ahead schedules are due two hours prior to the delivery.

The Miramar peaker also falls under the must offer obligation. Since the unit has a quick start capability and is certified for non-spinning reserve, SDG&E can comply with its must offer obligation by committing Miramar to provide non-spinning reserve during any period when it is not on an outage or scheduled for energy in a forward market. When Miramar is committed for non-spinning reserve, it satisfies a portion of the ancillary service obligation of SDG&E load, thus reducing CAISO charges by the value of that ancillary service.

In October 2004, through Amendment 60 to its Tariff, the CAISO made significant changes to the must-offer process. Amendment 60 accelerated the timeline for CAISO notification of waiver denial and removed the exclusion of minimum load cost recovery when ancillary service schedules were placed on a unit operating on a denied waiver. Under the new process, the CAISO must respond to the waiver request while the interim day-ahead market is open, allowing a day-ahead ancillary service schedule to be put on a resource in the interim market, if waivers are denied.

10. Ancillary Services

The SDG&E supply portfolio contains a number of resources capable of providing Ancillary Services (Regulation Up/Down, Spinning Reserve and Non-Spinning Reserve). The table below lists these resources and their A/S capabilities:

Unit Name	**Unit Capacity MW**	**Type**	**Regulation**	**Spin**	**Non-Spin**
Palomar Energy Center	541	Combined Cycle	[redacted]	[redacted]	[redacted]
Miramar Energy Facility	46	Combustion Turbine	[redacted]	[redacted]	[redacted]
Encina Unit 1	106	Steam Turbine	[redacted]	[redacted]	[redacted]
Encina Unit 2	104	Steam Turbine	[redacted]	[redacted]	[redacted]
Encina Unit 3	110	Steam Turbine	[redacted]	[redacted]	[redacted]
Encina Unit 4	300	Steam Turbine	[redacted]	[redacted]	[redacted]
Encina Unit 5	330	Steam Turbine	[redacted]	[redacted]	[redacted]
Encina CT	14	Combustion Turbine	[redacted]	[redacted]	[redacted]
South Bay Unit 1	145	Steam Turbine	[redacted]	[redacted]	[redacted]
South Bay Unit 2	149	Steam Turbine	[redacted]	[redacted]	[redacted]
South Bay Unit 3	174	Steam Turbine	[redacted]	[redacted]	[redacted]
South Bay Unit 4	221	Steam Turbine	[redacted]	[redacted]	[redacted]
South Bay GT	15	Combustion Turbine	[redacted]	[redacted]	[redacted]

While the total A/S capacity from these resources exceeds SDG&E's bundled load requirements, the Encina and South Bay units were not economic to run for most hours of the record period, and therefore, SDG&E also purchased significant amounts of A/S from the CAISO.

SDG&E utilized two scheduling methods, economic bidding and self-provision scheduling, to schedule A/S on its resources capable of providing Regulation, Spin and Non-Spin. Economic bidding is used to capture the value of opportunity cost when the capacity could otherwise be used for energy instead of A/S. Self-provision is used to directly schedule A/S if the likelihood of energy dispatch is low due to factors including generation price and operational constraints limits. Self-provided ancillary services allow SDG&E to avoid a portion of the CAISO ancillary service charge, and therefore, the value of the avoided charges is included as a credit in the variable cost analysis for the dispatch.

11. Market Transactions

SDG&E utilizes several types of market transactions as basic tools in the least cost dispatch process. Energy purchases and sales are market transactions that create a net decrease or increase, respectively, in SDG&E's load requirement that must be met from the supply portfolio. Economic purchases are made to reduce more costly generation dispatch and economic sales are made to monetize unused generation capacity.

Exchanges and swaps are economic market transactions that do not change the net load requirement, but rather improve the "shaping" of load requirements within a delivery period to allow for more efficient dispatch of the supply portfolio. SDG&E's ability to utilize market transactions to improve least cost dispatch is subject to the availability and pricing of the desired products during the least cost dispatch process.

During the record period, SDG&E actively engaged in market purchases and sales that were economic relative to the variable cost of its dispatchable resources. The energy transactions, executed at prices consistent with prevailing market conditions, included standard on-peak and off-peak blocks and non-standard products such as individual hour, super-peak or shoulder-hour energy. SDG&E evaluates a number of factors besides the straight comparison of market price to SDG&E's portfolio variable cost to determine the benefit of market transactions. These factors include best fit for SDG&E's load profile, counterparty credit availability, congestion risk mitigation and avoidance of unit-commitment costs such as start-up and minimum load carrying costs.

When making economic sales from its portfolio, SDG&E seeks opportunities on a forward basis (day-ahead or hour-ahead) or in the real-time imbalance energy market at prices that at a minimum recovered all variable generation costs. SDG&E typically reserves a portion of available generation to sell into the real time sales. While this approach lacks the pricing and quantity certainty of forward trades, the real-time market benefits SDG&E by providing diversification of pricing, avoidance of outage risk and an offset to real-time energy purchases in the event actual load exceeds scheduled load.

SDG&E may also make energy purchases and sales to respond to operational requirements that take precedence over least cost dispatch economics. A typical operational need to buy energy occurs when a resource in SDG&E's portfolio is forced out and SDG&E must replace the lost generation. A typical operational need to sell energy occurs when must-take energy exceeds load; SDG&E may need to dispose of the surplus energy when market prices are lower than the cost incurred.

On occasion, constraints on the gas supply system can also impact least cost dispatch. When the gas system has a high inventory, the pipeline operator can declare an Operational Flow Order (OFO), which places severe penalties on pipeline users if they fail to consume gas nominated for delivery. When an OFO occurs, SDG&E must factor in the OFO penalty in its least cost dispatch decision making process, if reduction in dispatched generation is an option under consideration. A high inventory OFO can depress energy prices due to gas over supply, but it may not be possible to take advantage of the price movement by displacing dispatchable generation with market purchases due to the minimum requirement on gas delivery to generation.

In addition to outright purchases or sales, SDG&E also engages in other types of market transactions, which are intended to reduce overall procurement costs or reduce the risk of congestion charges. These transactions include exchanges and swaps.

Exchanges typically do not add to the net energy supply for the operating day, but they do shift the energy from a period of surplus to a period of need. The transaction involves sending energy to a third party in one period and receiving a similar, but not necessarily equal, amount of energy from the same party in a different period of that day.

SDG&E occasionally has excess power [redacted] At the same time, SDG&E is usually short energy [redacted]. SDG&E may find counterparties on a day-to-day basis willing to receive energy [redacted] and deliver it [redacted]. These transactions allow SDG&E to balance the shape of delivered supply to the load shape. They are done at either a flat price (i.e., no exchange of cash) or a negotiated fee that is less than the total savings achieved via the transaction. Exchanges have two advantages over selling and buying each side of the transactions separately. First, because opportunities to buy such "odd lots" are relatively rare, these energy exchanges are more efficient from a price discovery standpoint, since SDG&E does not have to negotiate two separate prices with two counterparties. Second, exchanges reduce the credit requirement, since the energy is typically exchanged on the same day.

Swaps are another type of transaction regularly employed by SDG&E to reduce overall portfolio costs. Like exchanges, swaps typically do not add to the net energy volume for the day. Swap transactions involve an exchange of energy at one location for a like amount of energy at a different location during the same hour. Swaps can be used to avoid potential congestion charges, reduce or eliminate the charges assessed by the CAISO for transmission losses on imports, or take advantage of a price differential between locations. SDG&E regularly employs swaps with its Boardman and YCA power purchase contracts and the Sunrise dispatchable contract.

The Boardman contract is normally scheduled as an import at the COB to serve SDG&E load in SP15, which exposes the energy to transmission loss charges and potentially to congestion charges on all intervening paths (i.e., COB, Path 15 and Path 26). If SDG&E sells this energy at COB and repurchases the same quantity in SP15, SDG&E avoids incurring transmission loss charges and CAISO grid management charges. Additionally, this swap eliminates congestion risk that would have been incurred by scheduling the COB power across Path 15 and Path 26, which are potential congestion points.

The YCA contract is normally scheduled into SP15 at the import point North Gila, located in Arizona. As with the Boardman contract energy, SDG&E can sell this power at North Gila or Palo Verde and buy replacement power at SP15, saving ratepayers the CAISO charges associated with transmission losses and congestion risks.

12. Supplemental Energy Bids

To ensure that unscheduled generation capacity is available to the market, SDG&E submits supplemental energy bids for uncommitted (and available) generation to the CAISO. Supplemental energy bids supply the CAISO with price information so the CAISO can economically dispatch (up or down) available generation capacity in the real-time energy market. SDG&E establishes supplemental bids to cover all variable costs associated with real-time dispatch. In addition to standard fuel and variable O&M costs, SDG&E also factors in start-up costs for fast-start units (peakers), CAISO grid management charges and a margin to account for fuel price changes and other operational contingencies.

During the record period, SDG&E submitted supplemental energy bids for the Palomar combined cycle plant, Miramar peaker, and the Encina and South Bay units. No supplemental energy bids were submitted for DWR generation (Sunrise and Calpeak). Real-time dispatch on the Calpeak units is outside the scope of the DWR contract, and Sunrise was granted an exemption from real-time dispatch requirements by the CAISO due to gas balancing constraints.

13. Operational Administration of DWR Contracts

In addition to the foregoing least cost dispatch elements and processes, SDG&E Electric Procurement personnel meet (via teleconference) each week with DWR to discuss issues which arise under the SDG&E operational administration of the allocated DWR contracts. Routine topics during these teleconferences include gas supply administration, gas and electric settlement, resource availability (such as testing and outage planning) and regulatory filings. During the record period, the following major topics were regularly discussed:

- Scheduling Coordinator for Sunrise: SDG&E assumed responsibility as the Scheduling Coordinator (SC) for the Sunrise unit in mid-2008 from Edison Mission. The benefits of this change include more efficient scheduling due to the elimination of the Edison Mission / SDG&E schedule requirement, closer outage coordination and operational communication with the plant and the elimination of the $3,000/month SC fee previously paid to Edison Mission.
- Transition to MRTU: SDG&E and DWR discussed scheduling and settlement issues related to transitioning DWR contracts into the MRTU market. Discussions focused on preserving least-cost dispatch and establishing clear settlements protocols. The Calpeak contract transition was complicated by the fact that SDG&E is not the SC for the Calpeak units. This resulted in the need to establish new protocols for bidding and inter-SC trades (ISTs) between SDG&E and Calpeak, and settlements procedures between SDG&E and Calpeak and between SDG&E and DWR. The Sunrise contract transition was relatively

straightforward because it focused on MRTU bidding strategy rather than SC-SC or settlement issues since SDG&E is the SC. The J.P. Morgan Contract C transition was the most straightforward due to the simple substitution of ISTs in lieu of SC-SC schedules in the day-ahead market. The Cabazon and Whitewater wind contracts are also straightforward conversions of SC-SC schedules to ISTs, although these ISTs are submitted into the real-time market to match the wind generation schedules.

- Real-time dispatch from Sunrise: Real-time dispatch adds incremental value to a generation resource because it can respond (within operational limits) to real-time price market prices. Currently, Sunrise does not provide real-time dispatch due to a relatively stringent gas balancing limit allowed by Kern River Pipeline.
- Gas Supply: SDG&E continued to perform the gas supply function for DWR's Sunrise and Calpeak contracts as agent for CDWR. SDG&E also performed the gas management function for the Sunrise contract. SDG&E continued to request that DWR implement a master gas trading agreement that would allow for physical gas transactions between SDG&E and DWR. This agreement would allow SDG&E (as Sunrise's fuel manager) to transfer gas between the SDG&E and DWR gas portfolios, and would benefit both portfolios in avoiding transaction costs and meeting pipeline balancing requirements. Unfortunately, DWR continued to uphold its preference to not enter into a NAESB with SDG&E in 2008.

VII. CONCLUSION

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 has consistently followed the Commission's directive to only consider variable costs in making its dispatch decisions. As a result, all costs recorded to SDG&E's 2008 ERRA should be fully eligible for cost recovery through rates.

This concludes my prepared direct testimony.

VIII. QUALIFICATIONS

My name is Tony Choi. My business address is 8315 Century Park Court, San Diego, CA 92123. I am currently employed by SDG&E as Transaction Scheduling 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 CDWR contracts, transacting in the real-time wholesale market and managing scheduling activities in compliance with CAISO requirements. I assumed my current position in March 2007.

I previously managed the Electric Power and Generation Gas Trading desks for SDG&E, primarily managing day-ahead and forward procurement of energy on a least cost dispatch basis. Prior to joining SDG&E in 2002, my experience included two years as a power plant engineer, four years as an energy trader and three years as a wholesale energy transaction structurer.

I hold a Bachelors degree in Chemical Engineering and a Masters degree in Business Administration from the University of California. I have previously testified before the CPUC.

BEFORE THE PUBLIC UTILITIES
COMMISSION OF THE STATE OF CALIFORNIA

DECLARATION
OF TONY CHOI

A.09-05-______
Application of San Diego Gas & Electric Company (U 902 E)
For Approval of its Contract Administration, Least Cost Dispatch and Power Procurement Activities, and Costs Related to Those Activities, Incurred Between January 1, 2008 and December 31, 2008

I, Tony Choi, do declare as follows:

1. I am the Transaction Scheduling Manager for San Diego Gas and Electric Company ("SDG&E). I have included my Direct Testimony ("Testimony") in support of SDG&E's Application for Approval of Contract Administration, Least Cost Dispatch and Power Procurement Activities, and Costs Related to Those Activities, Incurred Between January 1, 2008 and December 31, 2008. Additionally, as Transaction Scheduling 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 procedure set forth in the August 22, 2006 Ruling of ALJ Thomas, I am addressing each of the following five features of Ordering Paragraph 2 of D.06-06-066:

- that the material constitutes a particular type of data listed in the Matrix;
- the category or categories in the Matrix the data correspond to;
- that SDG&E is complying with the limitations on confidentiality specified in the Matrix for that type of data;
- that the information is not already public; and

- that the data cannot be aggregated, redacted, summarized, masked or otherwise protected in a way that allows partial disclosure.

3. The 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 I – IOU Matrix in D.06-06-066.

Confidential Information	**Matrix Reference**	**Reason for Confidentiality**
Footnote 9 on page TC-5	XI. and VII.B.	Monthly Procurement Costs (ERRA Resource Recovery Account Filings) Confidential pricing terms in power purchase agreement
Table on page TC-15	I.A.4	Long-term Fuel Buying Plans
Table on page TC-23	VI.A	Utility Bundled Net Open (Long or Short) Position for Capacity (MW)
Text on page TC-26 lines 11 - 14	VI.B	Utility Bundled Net Open (Long or Short) Position for Energy (MWh)

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.

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.

[1] In addition to the details addressed herein, SDG&E believes that the information being furnished in my Testimony is governed by Public Utilities Code Section 583 and General Order 66-C. Accordingly, SDG&E seeks confidential treatment of this data under those provisions, as applicable.

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

Executed this 19th day of May, 2009, at San Diego, California.

Tony Choi
Transaction Scheduling Manager
San Diego Gas & Electric Company