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Witness: Andrew Scates

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SAN DIEGO GAS & ELECTRIC COMPANY

PREPARED DIRECT TESTIMONY OF

ANDREW SCATES

PUBLIC VERSION

BEFORE THE PUBLIC UTILITIES COMMISSION

OF THE STATE OF CALIFORNIA

May 31, 2013

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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, 2012, as specified by applicable California Public Utilities Commission ("Commission") decisions. LCD pertains to the day-ahead and intra-day dispatch and trading of SDG&E's portfolio of resources, including utility-owned generation ("UOG"), power purchase agreements and allocated California Department of Water Resources ("CDWR") contracts. The following sections describe Commission decisions on LCD and how SDG&E implemented these decisions in a manner consistent with its Commission-approved Long-Term Procurement Plan ("LTPP").[1]

SDG&E has filed four quarterly advice letters ("AL") covering the record period (AL 2352-E, AL 2391-E, AL 2411-E, and AL 2456-E for Q1 through Q4 2012, respectively) as required in Decision ("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 Q1 and Q2 of SDG&E's Quarterly Compliance Reports ("QCR") for 2012, concluding that SDG&E's LCD transactions for electricity and natural gas were 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 2012 Q3 and Q4 QCRs, for which approval are currently expected in the third/fourth quarter of 2013, the Commission's Energy Division issued its approvals establishing that the LCD transactions

[1] For purposes of the Commission's review and the compliance findings requested herein, the relevant Long-Term Procurement Plan (LTPP) is SDG&E's 2010 LTPP, approved in Commission Resolution E-4543, in compliance with D.11-05-005, D.12-01-033 and D.12-04-046.

reflected in SDG&E's QCRs were in compliance with SDG&E's Commission-approved LTPP, and applicable procurement-related rulings and decisions.[2]

II. SDG&E PORTFOLIO OVERVIEW

For the record period, most of SDG&E's energy requirements were met with SDG&E PPAs, UOG and allocated CDWR contracts. SDG&E's PPAs included Qualifying Facility ("QF") contracts and contracts for renewable energy, dispatchable generation and out-of-state resources, all of which are described in the Direct Testimony of SDG&E witness Sally Chen. UOG included SDG&E's 20% share of the San Onofre Nuclear Generating Station ("SONGS")[3], combined-cycle plants (Palomar Energy Center ["Palomar"] and Desert Star Energy Center ["Desert Star"]), and combustion turbine ("CT") generators (Miramar I ["MEF I"] and II ["MEF II"] [collectively, MEF I and II are known as "Miramar"]). Allocated CDWR contracts included two wind contracts and the Sunrise combined cycle plant (through June 2012). For the record period, the significant changes to SDG&E's portfolio were the addition of Cuyamaca Peak Energy Plant (45.2 MW) and the Lake Hodges Unit 2 (20MW).

The tables below provide summary data for resources in the SDG&E/CDWR portfolio. The must-take resources in Table 1 are non-dispatchable; SDG&E has an obligation to accept the generation that is produced from them without regard to variable cost and therefore they were exempt from SDG&E's LCD process described in this testimony (with limited economic curtailment rights on two QF contracts). The total of their generation in part determines SDG&E's net long or short position, which did factor into LCD. The resources in Table 2 are dispatchable, and were therefore the focus of SDG&E's least cost process during the record period.

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[2] D.02-10-062, Conclusion of Law ("COL") 7, p. 73; D.03-12-062, pp. 78-79; Ordering Paragraph ("OP") 20 and, D.07-12-052, pp. 185 -192.

[3] SONGS 2012 operation and outage issues and associated recorded estimated market-related costs will be addressed in the SONGS Order Instituting Investigation (I.12-10-013) ("SONGS OII"). SDG&E served supplemental testimony (Exhibit No. SDG&E-09) that will address these issues in Phase I SONGS OII August hearings.

Table 1: Must-Take Resources

Resource	Capacity MW	Dispatch Profile	Ancillary Service Capability
SONGS (nuclear)	450	Baseload	None
QF contracts	221	Baseload with limited economic curtailment	None
Renewable non-wind	120	Baseload (as available)	None
Wind (includes CDWR wind contracts)	433 (maximum)	Intermittent	None

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

Table 2: Dispatchable Resources

Resource*	Capacity MW	Dispatch Profile	Ancillary Service Capability
Palomar CCGT Natural Gas SP15	566	Load Following	Spinning Reserve Regulation
Otay Mesa CCGT Natural Gas SP15	604	Load Following	Spinning Reserve Regulation
Sunrise CCGT Natural Gas ZP26	590	Load Following	None
Cuyamaca CT Natural Gas SP15	45	Peaker	Non-Spinning Reserve
Miramar 1 CT Natural Gas SP15	48	Peaker	Non-Spinning Reserve
Miramar 2 CT Natural Gas SP15	48	Peaker	Non-Spinning Reserve
Boardman Coal ST Coal Import into NP15	83	Baseload	None
Orange Grove CT Natural Gas SP15	99.9	Peaker	Non-Spinning Reserve
El Cajon Energy Center CT Natural Gas SP15	48	Peaker	Non-Spinning Reserve
Desert Star CCGT Natural Gas Import into SP15	495	Load Following	Spinning Reserve
Lake Hodges Unit 1 Hydro SP15	20	Pumped Storage	None
Lake Hodges Unit 2 Hydro SP15	20	Pumped Storage	None

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

III. COMMISSION DIRECTION FOR LEAST COST DISPATCH

In D.02-09-053, which allocated the CDWR 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"[4] 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."[5] In that same decision, the Commission provided direction by which a utility should implement LCD of the combined utility/CDWR portfolio:

> [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.[6]

Thus, the Commission explicitly requires IOUs to consider only variable operating cost for LCD and not to consider fixed costs. For clarity, fixed costs are those that are incurred regardless of the dispatch of the resource. The capital costs of utility-owned generation investments, capacity payments for tolling contracts, financial hedges, pipeline capacity charges and Congestion Revenue Rights ("CRR") costs/revenues are examples of fixed costs.

The LCD requirement was further established 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 CDWR 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."[7]

Subsequently, the Commission provided guidance on the appropriate level of demonstration that each IOU complied with SOC 4:

> We [the Commission] went on to state that the least cost dispatch review process is a compliance review, and that there are no ranges of possible outcomes. (D.05-01-054, pp. 13-14). Instead, we stated in the pertinent part that:

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[4] D.02-09-053, at 71-72, OP 2.
[5] *Id*. at 72-73, OP 5.
[6] *Id*. at 39.
[7] D.02-10-062, p. 52 and COL 11, p. 74.

> The outcome or standard for review has been predetermined – that is the lowest cost. SCE ***must demonstrate that it has complied with this standard, by providing sufficient information and/or analysis in order for the Commission to verify that SCE's dispatch resulted in the most cost-effective mix of total resources, thereby minimizing the cost of delivering electric services***. Based on analyses of SCE's showing and subsequent discovery, ORA or any other party may take the position that SCE did not fully comply with SOC 4. In such cases, we will judge the merits of the parties' positions and may impose disallowances and/or penalties…. This compliance process encompasses much more than that characterized by ORA. Imposing a compliance process for least-cost dispatch under SOC 4, rather than a reasonableness review process, does not diminish our ability to ensure just and reasonable rates. (D.05-01-054, pp. 14-15.)[8]

In this same decision, the Commission goes on to say that:

> ***D.05-01-054 did not adopt specific criteria for determining "what constitutes least-cost dispatch compliance or what the utility needs to provide to meet its burden to prove such compliance."*** (D.05-01-054, p. 15.) Instead, we stated that if ORA or another party can demonstrate that the utility "has not dispatched resources in a least-cost manner, the Commission will review that evidence and make appropriate adjustments for non-compliance." (D.05-01-054, p. 16.)[9]

The Commission also determined in D.05-01-054 that the scope of LCD review should cover the dispatch of resources in the day-ahead, hour-ahead and real-time markets.[10]

In D.03-06-076, the Commission recognized that, while IOUs endeavor to meet the LCD standard, actual achievement of the most cost-effective mix of resources may be constrained by non-economic factors:

> 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…. ***with the recognition that a pure economic dispatch of resources may need to be constrained to satisfy operational, physical, legal, regulatory, environmental, and safety considerations***. [11]

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[8] D.05-04-036 at 26 (emphasis added).
[9] *Id*. at 27 (internal footnote omitted) (emphasis added).
[10] D.05-01-054, COL 2, p.36.
[11] D.03-06-076 at 23 (emphasis added).

Finally, disallowances for violations of SOC 4 are subject to a cap equal to twice the IOU's annual expenditure on all procurement activities.[12]

IV. IMPLEMENTATION OF LEAST COST DISPATCH

The goal of LCD is to achieve the most cost-effective mix of total resources, thereby minimizing the cost of delivering electric services. To meet this goal, SDG&E implements a LCD process that it has presented in each of the previous Energy Resource Recovery Account ("ERRA") compliance filings. This process is comprised of several functions as follows:

- Planning is a forward assessment of SDG&E's expected load, resource availabilities, variable costs, and market prices to forecast the lowest cost mix of resources, including market energy, to meet load.
- Trading is the purchase of market energy below the variable cost or sale of surplus generation above the variable cost of SDG&E's resources.
- Self-scheduling and bidding is the process of offering SDG&E's resources into the California Independent System Operator ("CAISO") markets for dispatch in line with variable operating costs and operational constraints.
- Market award retrieval and validation requires downloading and communicating CAISO market awards for energy and ancillary services to SDG&E's resources so they can be effectively dispatched to meet CAISO instructions. Following the delivery date, SDG&E retrieves additional market data and analyzes market awards and settlement results to ensure they are in line with SDG&E's self-schedules and economic bids.

Performance of these functions essentially embodies the LCD principles established by the Commission. In Section VI, SDG&E demonstrates how it performs each of these functions within its LCD process to comply with SOC 4. Prior to the detailed discussion of these functions, a summary of the CAISO market (post-Market Redesign and Technology Upgrade ("MRTU")) is provided in the next section to provide context for SDG&E's LCD process.

Importantly, as the Commission acknowledged in D.03-06-076, the ***results*** of such dispatch activities will not align with pure LCD because they are constrained by non-economic

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[12] D.03-06-067, OP 3(a).

limitations. Specific examples of such limitations that affected SDG&E during the record period include:

- Load forecast uncertainty
- Operational constraints of generators in SDG&E's portfolio
- Modeling limitations of variable costs, including unit commitment costs
- Lack of *ex ante* knowledge of market prices

Therefore, an after-the-fact review of LCD results alone is not fully informative of whether SDG&E complied with SOC 4. A more appropriate review must consider SDG&E's LCD process, and whether it enabled the lowest-cost mix of resources to be achieved subject to such limitations in effect at the time.

V. CAISO MARKET OVERVIEW AND SDG&E PARTICIPATION

On April 1, 2009, following Federal Energy Regulatory Commission ("FERC") approval of its market redesign application, the CAISO implemented the MRTU, which introduced fundamental changes in the way resources are committed and dispatched. The most significant of these changes was the implementation of a centralized energy market which requires load-serving entities ("LSE") to procure energy and ancillary services ("A/S"), and generators to sell energy and A/S, through the CAISO markets based on self-schedules and economic bids.
Prior to MRTU, load-serving entities assessed the costs of their supply options, including market energy, and submitted schedules to the CAISO balancing those supplies with their load or sales obligations. MRTU established a centralized spot market that enables all resources, through standardized bidding and scheduling rules, to be competitively dispatched based on variable costs to serve total system load, subject to operational and transmission constraints. These resources are no longer matched up to any particular LSE's load; LSEs now meet their needs by self-scheduling or bidding for energy in the CAISO market. However, LSEs may still rely on bilaterally procured resources to hedge the day-to-day cost of buying energy and A/S from the CAISO markets, to the extent these contracted resources pass on the revenues for energy and A/S awards received from those same CAISO markets back to the LSE.

SDG&E modified its LCD process to meet new MRTU-related CAISO tariff rules and operating requirements while maintaining compliance with SOC 4, particularly in regard to self-schedules and economic bids for its dispatchable resources. These self-schedules and bids must accurately reflect variable costs to enable the CAISO market to produce energy and A/S awards for SDG&E's resources that are consistent with LCD.

The CAISO market solves for the least cost unit commitment and dispatch solution incorporating self-schedules and economic bids from generators and load, various resource operational constraints and a full transmission network model that considers transmission constraints throughout the CAISO system. The nodal ("Pnode") market prices explicitly account for the economic effects of re-dispatching resources to relieve congestion constraints. The CAISO optimizes the dispatch of the several hundred generators across its system to find the overall lowest-cost mix of resources to meet CAISO system load requirements (including those of SDG&E).

The CAISO market also co-optimizes the allocation of dispatchable capacity between generation and A/S capacity, based on prices submitted for each of these services in the resource bids.[13] 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.

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

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

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

> ***co-optimization methodology that maximizes economic efficiency, relieves network Congestion and considers physical constraints***. The economic efficiency of the market operation can be achieved through a least cost resource commitment and scheduling with co-optimization of Energy and Ancillary Services.[14]

A feature of the CAISO market is the ability for market participants to submit self-schedules rather than economic (or price) bids for load and generation. A self-schedule is a price-taker bid that is awarded regardless of the Pnode price (even if negative) subject to operational constraints. SDG&E submits a self-schedule for its forecasted load in the day-ahead market. SDG&E also submits self-schedules for its (non-wind) must-take resources in the day-ahead market.[15] This approach is needed because SDG&E has an obligation to receive energy from these resources, regardless of the market price, and self-scheduling in the day-ahead market ensures that revenues paid to these resources effectively offset costs charged to SDG&E load. SDG&E submits self-schedules for its wind resources in the hour-ahead scheduling process to comply with the CAISO's Participating Intermittent Resource Program ("PIRP") requirements. However, beginning in February of the record period, SDG&E began to submit convergence bids for its wind resources to shift the revenues from the real-time market to the day-ahead market to achieve the day-ahead energy revenue/load cost offset described above.

SDG&E must be selective in its use of self-schedules for dispatchable generation, since self-schedules could conflict with the LCD requirement to consider variable costs. Dispatchable generation is self-scheduled into the CAISO market primarily for the following reasons:

- Limiting downward dispatch of resources in the real-time market to manage SDG&E's exposure to real-time prices
- Mitigation of uneconomic unit cycling
- Managing CAISO modeling limitations
- Unit testing that requires the generator to run at a minimum output level
- Ensuring that peakers are dispatched for the time period they are needed
- Initial conditions
- Self-scheduling of Lake Hodges

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[14] CAISO Technical Bulletin: Market Optimization Details, November 19, 2009 at 2-8 (emphasis added).
[15] For brevity, this testimony does not distinguish between SDG&E or the resource owner performing the Scheduling Coordinator functions for SDG&E's resources.

- Avoidance of Bid Cost Recovery ("BCR") uplift allocation
- Achieving a minimum fuel burn as required

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

Consequently, SDG&E primarily submits cost-based price bids for its dispatchable generation rather than self-schedules. Price bids assure that SDG&E ratepayers will recover the variable costs associated with start-up, minimum load and dispatch from the market. Moreover, price bids enable the CAISO to perform its co-optimization between energy and A/S awards. Finally, with respect to LCD, price bids allow for CAISO market results to meet the least cost dispatch solution across the entire system, including SDG&E's service territory, because the CAISO selects the mix of resources with the lowest total variable cost (as represented by their price bids) to meet load requirements. To the extent SDG&E submits cost-based price bids reflecting variable costs per D.02-09-053, and accurately presents operational parameters and constraints to the CAISO, the results produced by the CAISO markets for SDG&E's supply portfolio are consistent with the Commission's LCD requirements.

VI. LEAST COST DISPATCH PROCESS

SDG&E's LCD process is managed by the Electric and Fuel Procurement department ("E&FP"). Key personnel involved in daily LCD activity in 2012 included fuels traders and schedulers, power traders, preschedulers and real-time schedulers. The LCD process consisted of a number of parallel functions, which are described in this section.

A. Pre-Day-Ahead Planning

LCD for a particular delivery date began with a weekly production cost model that optimized resources to serve SDG&E's load requirement for the following 12-day period. The model software (GenTrader)[16] 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 to produce a preliminary forecast of generation dispatch and market transactions that minimized total variable cost to serve the forecasted load requirement.

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 and Dispatch, Energy Risk Management and Settlements and Systems, to ensure that results were consistent with LCD standards.

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

a. <u>Load forecasts</u>: Load forecasts were developed along several time frames, such as 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"). This application analyzes relationships between historical system load and weather data, and develops an hourly load forecast for the 12-day plan, the day-ahead plan and intra-day LCD. 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.[17] SDG&E monitored the accuracy of its load forecast on an hourly

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[16] 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/solutions-products/gentrader/.

[17] 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.

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. <u>Resource operating parameters</u>: The model required a variety of data for each dispatchable resource to properly determine its dispatch cost. Such data included heat rates, ramp rates and variable operation and maintenance costs, 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, multi-stage generation ("MSG") transitions and ramp rates. The model optimized the dispatch of each resource given its generation cost and operating constraints.

c. <u>Forecast of resource availability</u>: A significant portion of SDG&E's portfolio is comprised of must-take resources (nuclear, QF and renewable energy), as listed in Section II. 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. If these availabilities varied from the full operating capability, they were communicated to the CAISO via the Scheduling and Logging for ISO of California ("SLIC") application as required.

d. <u>Market prices</u>: 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 the New York Mercantile Exchange ["NYMEX"], Intercontinental Exchange ["ICE"] and broker quotes) and tariff or contract gas transportation costs. Power prices were based on forward power price curves for block power (derived from ICE and broker quotes) and shaped for each hour using price weighting factors derived from historical price and load profiles.

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

GenTrader was then used to calculate the hourly dispatch level of dispatchable resource over the modeled period that was economic, or "in-the-money," relative to 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 generally consistent with resource data template ("RDT") data used by the CAISO in its market processes. For must-take resources, generation was assumed to equal their forecasted availabilities. If the sum of must-take and in-the-money dispatchable generation was less than that hour's load requirement, the short position, or Residual Net Short ("RNS"), was considered to be met with market purchases. If the sum of must-take and in-the-money generation was greater than that hour's load requirement, the long position was considered to be surplus generation available for economic market sales.

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

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

The Goal Line QF contract allowed SDG&E to economically curtail the contract for up to five hours each day of the year. If the 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.

B. Day-Ahead Planning

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

a. Load forecast: SDG&E used updated temperature and humidity forecasts from SDG&E's weather forecasting service to re-run its AANNSTLF load forecasting model. In addition, pre-schedulers applied manual adjustments to the AANNSTLF result when warranted to offset known limitations to the model. For example, because AANNSTLF forecasts are based on historical data, AANNSTLF lagged sudden changes to the weather forecast such as the onset of a heat wave. The prescheduler also benchmarked the AANNSTLF 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. These updates were also submitted to the CAISO via the SLIC application as required.

c. Market prices: Spot natural gas and power trade actively in the day-ahead market. Updated prices fed into the model reflected actual market conditions rather than a price forecast.

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

C. <u>Day-Ahead Trading and Scheduling</u>

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

- <u>Load</u>: During the record period, SDG&E sought to self-schedule 100% of the day-ahead bundled load forecast. Self-scheduling ensured that SDG&E would purchase its forecasted load requirement in the day-ahead market rather than rolling the requirement into the real-time market which produces more volatile prices. The day-ahead market was preferred for two other reasons. The first reason was that SDG&E was required to self-schedule or bid in its (non-use limited) resources into the day-ahead market under Resource Adequacy must-offer rules in the CAISO Tariff. Therefore, while balanced schedules were not mandated, the DAM did provide a means for supply revenues to effectively offset the load costs provided that SDG&E self-scheduled its load in the DAM. The second reason was that the depth of the day-ahead bilateral market allowed SDG&E to hedge its self-scheduled load exposed to the CAISO DAM clearing price via bilateral fixed-price transactions.
- <u>Non-wind must-take resources</u>: SDG&E continued to self-schedule available must-take generation on a day-ahead basis to offset DAM load awards. For resources that were scheduled by sellers and not SDG&E, sellers continued to self-schedule their available generation into the DAM. Credit for the Day Ahead ("DA") revenues was transferred back to SDG&E either via an Inter-SC Trade ("IST") for the self-scheduled quantity, or settled after the fact by the settlements group.
- <u>Wind generation convergence bids</u>: All SDG&E wind resources were scheduled in the hour-ahead scheduling process as required by the CAISO's Participating Intermittent Resource Program ("PIRP"). SDG&E utilized convergence bids to effectively shift the

CAISO's payment for wind generation from the real-time market to the DAM, thereby providing a better offset to load charges which, as discussed above, settle against DAM prices. The Commission authorized this application of Convergence Bidding in D.10-12-034. The daily process consists of three main steps: (1) retrieval of the day-ahead PIRP forecast for each wind resource; (2) creation of convergence bid quantities considering a) the percentage of the day-ahead PIRP quantity forecast to be shifted into the day-ahead market, b) convergence bid quantity limitations imposed by the CAISO and c) reduction of quantities in hours that historically have tended to produce negative returns on the convergence bids SDG&E would have submitted; and (3) pricing of convergence bids such that the virtual supply is not sold at unreasonably low price levels. The results of SDG&E's convergence bidding activity were reported monthly to the Commission and Procurement Review Group ("PRG") as required by D.10-12-034.

- Dispatchable resources: SDG&E's objective, with respect to self-schedules and price bids for dispatchable resources, was to maintain adherence to LCD principles. This objective was primarily met by bidding generation into the DAM at cost–based prices consistent with the LCD modeling.[18]
- Generator price bids: There are three basic components - startup cost, minimum load cost and incremental energy bids. Startup and minimum load costs used in the day-ahead market were 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 cause deviations from the day-ahead LCD solution that SDG&E's model calculates based on lock-step pricing of power and natural gas. Also, bidding rules require that incremental energy bids be monotonically increasing over the range of output. This rule at times conflicted with the actual incremental energy cost of combined cycle plants because the true incremental cost decreases as well as increases as they transition through operating modes to ramp from minimum to maximum load. Therefore, SDG&E had to develop modified energy bid curves or employed MSG

[18] To a lesser extent, SDG&E utilized self-schedules for dispatchable resources as described in Section V. While self-schedules in themselves may not be consistent with least cost dispatch (since they do not present the market with operating costs), they did at times provide the benefits described in Section V in managing operational and market limitations and managing SDG&E's real-time exposure to real-time market prices.

modeling for its combined cycle fleet (Palomar, Desert Star, Sunrise and Otay Mesa) to comply with the monotonically increasing bid rule.

Other components of the price bid that pertained to A/S-certified units are bids for Regulation, Spinning Reserve and Non-Spinning Reserve. As discussed in Section V, the day-ahead market algorithm co-optimizes dispatchable capacity between generation and A/S awards; and 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 is typically not economically dispatched in the real-time market). Therefore, SDG&E incorporates an estimate of expected real-time energy market net revenues that the A/S capacity could otherwise derive from that market.

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

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

D. Hour-Ahead Scheduling and Real-Time Dispatch

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

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

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

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

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

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

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

E. Award Retrieval and Validation

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

SDG&E performed several post-market assessments to review market results and validate that the CAISO process resulted in LCD of SDG&E's portfolio. The first assessment is referred to as the Position Report. This report, created by scheduling staff once meter data became available following the delivery date, provided a summary of day-ahead market awards as well as incremental/decremental real-time generation and load. The second assessment is referred to as the Bid Evaluator report, provided through the PCI software package. Bid Evaluator compares SDG&E's expected day-ahead awards for its dispatchable generation based on published market prices with actual day-ahead market results. Generally, the market results aligned closely with Bid Evaluator results (subject to operational constraints), confirming that LCD of SDG&E's portfolio was achieved.

VII. EXAMPLES OF LEAST COST DISPATCH DATA

In Appendix 2, SDG&E presents illustrative LCD information that demonstrates SDG&E's implementation of the LCD process described in Section VI. A description of the information is provided below:

1. The AANNSTLF data table is the output from SDG&E's load forecasting tool. As discussed above, it produces an hourly forecast of total SDG&E system load based on a forecast of temperature and relative humidity, which can be compared directly to the CAISO's forecast of total SDG&E system load. Preschedulers will make adjustments to the finalized day-ahead system load forecast to arrive at SDG&E's bundled load forecast, which is scheduled in the DAM.
2. SDG&E receives availability notices for its dispatchable and must-take resources, which may affect LCD results. A sample availability notice is provided in Appendix 2.
3. Market prices are entered into GenTrader to determine the optimization between generation and market purchases and sales. Appendix 2 shows a screenshot of ICE prices that inform traders of market prices to be used to create the price forecast in GenTrader.
4. GenTrader results show the quantities of resources expected to clear the market based on variable operating costs and the price forecast, and inform traders of the direction and magnitude of SDG&E's long or short residual day-ahead position relative to load requirements.
5. Day-ahead bids for dispatchable resources are derived from the configuration of their operating parameters such as start-up costs and heat rates. Appendix 2 includes screen shots of Palomar's bids that SDG&E submitted into the CAISO's Scheduling Infrastructure & Business Rules ("SIBR") system, used to determine CAISO-wide least cost dispatch awards.
6. The screenshot of CMRI shows the day-ahead awards received for Palomar. As described in Section VI, SDG&E retrieves and communicates these awards to its dispatchable resource so that they can perform on their dispatch obligations in real-time.

7. SDG&E runs a Bid Evaluator study to assess the results of the day-ahead market for its dispatchable resources. The sample data in Appendix 2 show small deviations between realized and theoretical LCD results for Otay Mesa and Sunrise, which resulted from ambient, derate limitations for these two units that prevented them from being awarded up to their maximum load points.
8. SDG&E runs a post-market position report that summarizes day-ahead and real-time dispatches along with market prices. This report is an effective tool for assessing the supply and load awards as well as identifying market results that may require investigation.

VIII. CONSTRAINTS TO LEAST COST DISPATCH

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

Some constraints were operating limits inherent to the resources in the portfolio. For example, generators cannot continually cycle back and forth between online and offline because of minimum run time and shutdown time of each combustion turbine. Therefore, the lowest cost unit may not 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 on 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. All CAISO resources are obligated to comply with these dispatches.
- Residual Unit Commitment ("RUC") is a market award for capacity the CAISO issues to ensure that sufficient capacity is committed to meet system load. Although

RUC resulted from the market process, it is required to manage grid reliability and is outside the scope of LCD. SDG&E resources were obligated to be available to provide the RUC capacity if awarded, which required that they could be committed uneconomically relative to other resources.

- Unit testing and maintenance, such as Relative Accuracy Test Audit ("RATA") tests and heat treats, require generators to run at pre-defined load points to achieve an objective. During these periods, generation is considered must take and cannot be dispatched according to LCD economics.
- Constrained pipeline operations may impact LCD. Sunrise and Desert Star were constrained in their ability to provide real-time dispatch because of limited gas balancing rights on the Kern River and Southwest Gas pipelines. Another example of pipeline constraints are Operational Flow Orders ("OFOs") declared by Southern California Gas Company ("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.

IX. 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 dispatchable resources. These included SDG&E-owned or contracted resources (Miramar, Cuyamaca, Palomar, Desert Star, OMEC, Orange Grove and El Cajon Energy Center and the CDWR contract for the Sunrise unit). Fuel costs for SDG&E resources are charged to the ERRA, while fuel costs for CDWR resources are paid by CDWR and recovered through the CDWR retail remittance rate. No preference is given to either SDG&E or CDWR 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/CDWR Gas Supply Plan, SDG&E's procurement process is to secure approximately 90% of forecasted fuel volumes required to serve SDG&E's load forecast (but not economic sales) as firm monthly baseload supply. The advantages of baseload supply are that it (1) shields ratepayers from potentially volatile day-ahead natural gas prices; (2) is scheduled by market participants as a higher priority delivery than day-ahead supply; and (3) reduces the day-to-day trading and scheduling requirements, thereby reducing overall operational requirements. While the cost of baseload supply may be lower or higher than the spot price on any given day, over time these price differentials average toward zero, leaving SDG&E with the benefits cited above.

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

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

Throughout the record period, SDG&E held 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. FARs represent fixed costs and therefore are not considered in the LCD process.

SDG&E procured SoCalGas system storage capacity (in 2011) that was in effect from January 1 through March 31 of the 2012 record period and SDG&E also bid for and was awarded SoCalGas system storage capacity (in 2012) that was in effect from April 1 through December 31 of the 2012 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, fuels traders primarily relied on gas balancing services offered on SoCalGas' system and, to a lesser extent, on the Kern and Southwest Gas pipelines, or its storage capacity on SoCalGas' system. Occasionally, SDG&E traded and/or scheduled gas supplies in later pipeline scheduling cycles to avoid potential imbalance penalties. Activity in these later scheduling cycles was avoided to the extent lower availability of competitive bids and offers caused incremental transactions to be more costly to SDG&E.

X. SDG&E-OWNED GENERATION

During the record period, SDG&E operated and maintained its utility-owned generation resources (Palomar, Desert Star, Miramar, and Cuyamaca)[19] 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 CDWR, approved in D.02-12-069:[20]

> [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

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[19] 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.

[20] *See* D.02-12-069, Attachment A-3 at 5.

> 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.

Consistent with good utility practice, SDG&E established and followed a maintenance program to maximize the availability of the units as a primary "desired result." pecifically, 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.

Additionally, SDG&E is required to comply with the CPUC's General Order ("GO") 167 - Enforcement of Maintenance and Operation Standards for Electric Generating Facilities. Section 11 of GO 167 specifically outlines each generator owner's obligation to cooperate with the CPUC audits, investigations and inspections. Generally, this process includes the following steps:

- In accordance with General Order 167 Section 10.1.f, a forced/unplanned outage is reported to the CPUC representative assigned to the plant, the Consumer Protection and Safety Division ("CPSD") Utilities Engineer, via a daily status report email. If an outage is reported on the daily status report, a basic description of the outage is also included.
- Once the CPSD Utilities Engineer receives the email, a site visit is scheduled and a data request letter is sent to SDG&E management.
- During the site visit, the CPSD Utilities Engineer makes inquires as to the cause of the outage, outage duration, details of repairs required and extent of work to be done, equipment affected, evidence of repairs, and other questions pertaining to the recovery.
- The data request letter typically requires SDG&E to provide control room operator logs, generation curve in megawatts ("MW"), a root cause investigation or summary of the corrective actions, and general photographs that illustrate the outage details.

- After reviewing the response to the initial data request, the CPSD Utilities Engineer may issue additional data requests to obtain more information for review.
- The requests for data continue until the CPSD closes the inquiry.

In addition to what may be provided to the CPSD Utilities Engineer, each outage may provoke the creation of related documentation including, but not limited to, equipment affected, parts replaced, work required to accomplish outage related tasks, costs of repairs, actions that may be taken to mitigate a repeat of the failure, change to operating procedures required to address component or plant issues, changes to maintenance practices to improve reliability, communications with an original equipment manufacturer and implementation of upgrades to improve reliability. Evidence of the above can be found in parts ordering documents, SAP work orders, vendor invoices, investigation reports, management of change documents, and communications with vendors.

Finally, Sempra Energy's Internal Audit department also conducts audits of SDG&E's generating facilities. Consistent with auditing standards, the frequency and nature of such audits is determined based on an annual risk assessment which determines the areas of the company, including utility operations, to be audited. This risk-based analysis may change from year to year and in some years may include audits of URG operations.

Despite SDG&E performing maintenance on its generation resources consistent with Good Utility Practice, forced outages are experienced from time to time due to unforeseen operational problems. Forced outages in 2012 that spanned 24 hours or greater are generally described in Appendix 3.

An informative indicator of how competently an electric generation site is being run is to compare its Forced Outage Rate ("FOR") and availability to the industry average. The FOR shows the hours of unit failure as a percentage of the total hours of the availability of that unit. Availability simply expresses, as a percentage, the amount of time a unit is available for any given period of time. A lower FOR is better and a higher availability is better.

For example, the Palomar Energy Center, a 565 MW combined-cycle power plant, experienced a steam turbine generator (STG) problem on January 05, 2012 that caused the STG to be removed from service. While investigating the STG problem, Combustion Turbine Generator 1 (CT1) and Combustion Turbine Generator 2 (CT2) were kept available in simple-cycle mode, 2x0 (without operating the STG). When the plant staff determined that the STG needed to be disassembled for repair, a SLIC request was made for a planned outage for CT1 and CT2. CT1 and CT2 were scheduled out of service on January 09, 2012. The outage for CT1, CT2 and the STG ended on March 31, 2012 with the repair of the STG. SDG&E responded to a CPSD data request concerning the outage. Due to the STG failure, the STG achieved a FOR rate of [redacted]. The CT1 FOR rate was [redacted] and CT2 FOR was [redacted]. This compares favorably to an industry average of [redacted][21] The Miramar Energy Center ("MEF"), a 96MW peaking facility, achieved a FOR of [redacted] for MEF1 and MEF2 compared to the industry average of [redacted].[22] Cuyamaca Peak Energy Center ("CPEC"), a single peaking generator, achieved a FOR of [redacted] compared to an industry average of [redacted].[23] The Desert Star Energy Center, a 480 megawatt combined cycle plant achieved a FOR of [redacted] for the period of October 1 to December 31, compared to an industry average of [redacted][24]

When SDG&E experienced a forced outage on Palomar, Desert Star, Miramar, Cuyamaca or any other resource in its portfolio,[25] 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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[21] North American Electric Reliability Corporation (NERC), Generating Availability Report 2007-2011. This report is available on NERC's website: http://www.nerc.com/. 2012 data is not yet available.
[22] North American Electric Reliability Corporation (NERC), Generating Availability Report 2007-2011. This report is available on NERC's website: http://www.nerc.com/. 2012 data is not yet available.
[23] North American Electric Reliability Corporation (NERC), Generating Availability Report 2007-2011. This report is available on NERC's website: http://www.nerc.com/. 2012 data is not yet available.
[24] North American Electric Reliability Corporation (NERC), Generating Availability Report 2007-2011. This report is available on NERC's website: http://www.nerc.com/. 2012 data is not yet available.
[25] Included is SDG&E's 20% share of SONGS.

XI. CONCLUSION

My testimony describes SDG&E's plans for serving load from its fully integrated portfolio of utility-owned resources, power purchase contracts, allocated CDWR contracts and market transactions, consistent with the Commission-approved LTPP in effect for the record period. I also describe how SDG&E managed the operational, dispatch and administrative functions of the allocated CDWR 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 2012 ERRA should be fully eligible for cost recovery through rates. In summary, SDG&E's LCD process achieves the Commission requirements by considering variable costs, achieves the lowest cost mix, subject to constraints in the day-ahead, hour-ahead and real-time markets.

This concludes my prepared direct testimony.

XII. 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 a Market Operations Manager. My responsibilities include overseeing a staff of schedulers involved in dispatching the SDG&E bundled load portfolio of supply assets for the benefit of retail electric customers. This includes operational administration of DWR contracts, transacting in the real-time wholesale market and managing scheduling activities in compliance with CAISO requirements. I assumed my current position in January 2011.

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

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

I have previously testified before the Commission.

APPENDIX 1

Technical Bulletin

2009-06-05

MARKET OPTIMIZATION DETAILS

June 16, 2009
Revised November 19, 2009

Technical Bulletin
2009-06-05

Market Optimization Details

Table of Contents

1 Market Optimization

This document describes the two mathematical engines Security Constrained Unit Commitment (SCUC) and Security Constrained Economic Dispatch (SCED) that are used to perform Unit Commitment and Economic Dispatch respectively in CAISO Day-Ahead (DAM) and Real-Time Markets (RTM). The usage of each engine is described first followed by a more detailed explanation of the algorithmic processes within each engine.

This document is intended to provide an explanation of the CAISO's use of the SCUC and SCED procedures in clearing its markets and serve as a guide. The actual terms, rates and conditions of service in the CAISO Balancing Authority Area and on the CAISO Controlled Grid are as provided in the CAISO Tariff as filed with the Federal Energy Regulatory Commission, as amended from time-to-time. Additional details regarding the ISO's market processes and procedures are also contained in the CAISO Business Practice Manuals.

2 Security Constrained Unit Commitment (SCUC)

CAISO uses SCUC to run the processes associated with the commitment of Generating Units in DAM and the Hour-Ahead Scheduling Process (HASP) and RTM. SCUC uses a multi-interval Time Horizon to commit and schedule resources and to meet the CAISO Forecast of CAISO Demand in the Market Power Mitigation – Reliability Requirement Determination (MPM-RRD), Residual Unit Commitment (RUC), HASP, Short-Term Unit Commitment (STUC) and RTUC, and the bid-in Demand in Integrated Forward Market (IFM).

In the Day-Ahead MPM-RRD, the IFM and RUC processes utilize SCUC which optimizes over the 24 hourly intervals of the next Trading Day. In RTUC, which runs every 15 minutes, SCUC optimizes over 4, 5, 7 and 18 15-minute intervals that span a portion of the current Trading Hour and one to four subsequent Trading Hours.

In the HASP run, i.e., the RTUC that runs once per hour just before the top of the hour, and the associated MPM-RRD process, SCUC optimizes over seven 15-minute intervals comprising the last 45 minutes of the next Trading Hour and the entire subsequent Trading Hour for which new RTM bids are submitted and HASP schedules are produced. The following run of RTUC represents the STUC optimization over 18 15-minute time intervals. The next two runs of RTUC have five and four 15-minute intervals, respectively, in their Time Horizon, which includes the entire subsequent Trading Hour.

2.1 SCUC Algorithm

The Day-Ahead Market Clearing problem includes next-day Generation and Demand Bids. The objective of the problem is to minimize Energy and Ancillary Services (AS) procurement costs subject to all submitted Energy and Ancillary Services submitted supply bids and transmission constraints. A similar formulation is used to solve the Real-Time Market Clearing problem as well as the Residual Unit Commitment problem. In all cases, SCUC accepts operational data and Bids from resources and power system operating requirements (e.g., Demand forecast, reserve requirements, security constraints, etc.).

In Real-Time, unit commitment is limited to medium- and fast-start units and the dispatch is initialized from the State Estimator solution or telemetry. The SCUC commits and dispatches resources based on minimum cost as reflected by Bid prices, subject to network constraints.

The SCUC adjusts generation, load, import and export schedules and clears Energy Supply and Demand Bids, and AS bids to meet AS requirements, while managing congestion by enforcing linearized transmission constraints, and generating unit inter-temporal constraints. The linearized transmission constraints are identified using AC-based power flow and contingency analysis algorithms based on a Full Network Model (FNM). The FNM includes all CAISO Balancing Authority Area transmission network buses and transmission constraints, and possibly a reduced network representation of the rest of the WECC system. Additionally the SCUC calculates Locational Marginal Prices (LMPs) for Energy, network constraint Shadow Prices and Ancillary Services Marginal Prices (ASMPs) consistent with the AC-based power flow model.

SCUC employs a Mixed Integer Programming (MIP) methodology that effectively addresses the numerous modeling requirements and constraints required in the CAISO Markets.

The use of the MIP methodology with its advanced features allows CAISO to deal effectively with a number of Market design elements including the co-optimization of Energy and Ancillary Services, a large number of transmission and other security constraints, dynamic Ramp Rates, Forbidden Operating Regions.

In general, the SCUC co-optimization engine is capable of clearing markets for Energy and Ancillary Services including the following modeling and functional capabilities:

- Simultaneous optimization of the following commodities:
  - Energy
  - Regulation Up and Down
  - Spinning and Non-Spinning Reserve
  - Reliability capacity

- Least-cost Market Clearing based on:
  - Three-part Generation Energy Bids
  - Single-part load Bids
  - Single-part Inter-Tie Energy Bids
  - Ancillary Services Bids
  - RUC Availability Bids

- Network Congestion Management
  - Full AC network model including transmission losses
  - Security analysis (contingency constraints)
  - Nomogram constraints

- Marginal Pricing
  - Energy, network loss and transmission congestion LMP components
  - Ancillary Service prices for each Ancillary Service Region and each Ancillary Service Bid
  - RUC Prices

2.2 SCUC Modeling Requirements

As markets evolve and mature, there is an increasing requirement for more accurate and complete modeling of the transmission system. This requires iterating between the Unit Commitment (UC) software and Network Applications (NA), resulting in the need to solve the UC problem multiple times to obtain optimal results consistent with the limitation in the transmission system.

For this purpose the SCUC engine employs a Full Network Model (FNM) that is comprised of a detailed model of the physical power system network along with an accurate model of commercial network arrangements. These arrangements reflect the commercial scheduling and operational practices to ensure that the resulting Locational Marginal Prices (LMPs) reflect both the physical system and the actual scheduling practices. The commercial content of the FNM includes the following:

- Load modeling considerations, such as load aggregation, Load Distribution Factors, custom load aggregation, custom Load Distribution Factors, and Trading Hubs
- Resource modeling considerations, such as Pumped-Storage Hydro Units, System Resources, Participating Load, Generating Units, and Generation Distribution Factors for Aggregate Generating Resources
- Commercial transmission considerations, such as ETCs/TORs, New PTOs, Dynamic Schedules and pseudo ties
- Grouping and zone definitions, such as UDCs, price Locations, MSSs, Integrated Balancing Authority Areas (IBAAs), AS Regions, and RUC zones
- Other scheduling elements, such as power system equipment schedules

This dual role of the FNM allows SCUC to efficiently clear the market by co-optimizing Energy and Ancillary Services while managing Congestion and Transmission Losses. The FNM essentially represents the transmission network for CAISO Controlled Grid and is comprised of the following network components:

- The CAISO Balancing Authority Area encompassing the networks of the Participating Transmission Owners (PTOs)
- Metered Subsystems (MSS) that are part of the CAISO Balancing Authority Area
- Non-CAISO Balancing Authority Areas that are embedded within the CAISO Balancing Authority Area
- Networks of New Participating Transmission Owners (New PTOs)

- Utilities (currently called UDCs)

The FNM includes an accurate reactive power (MVAR) model to ensure that reactive power related constraints are respected. The use of reactive power in power systems is an effective way for improving both Power transfer capability and voltage stability. An AC power flow with local controls is implemented in the Network Applications. The operational status or Schedules of the manually operated reactive power/voltage control equipment are accounted for in the FNM. Although the FNM is an AC model, SCUC is not pricing reactive power.

In addition to its physical and commercial components, several other model-related inputs are required in the optimization and processing of the FNM in the IFM Markets. These inputs are a) the Ancillary Services Regions and requirements, b) Constraint definitions and management, c) Branch Groups/Interfaces and Nomograms, and d) contingency definitions and management.

The power system transmission constraints in both the base case and contingency cases are included in SCUC optimization. The transmission power flows of the transmission system branches may be constrained in either direction. The set of transmission constraints selected to be included in the optimization are consistent according to specific constraint definition criteria. Any constraint loaded in base or contingency cases above a certain user adjustable percentage, e.g., 95%, of the transmission equipment loading is included in the optimization.

It should be noted that certain transmission constraints are monitored only (i.e., not enforced). These are monitored against the defined limits adjusted by certain percentages of the limit.

For analytical functions, e.g., “AC power flow” program, a number of slack bus options are provided, such as distributed load, distributed Generation, and single user selectable slack. The slack bus options affect the distribution of network loss deviation in the AC Power Flow solution, and thus the decomposition of the LMP between the System Marginal Energy and Marginal Loss Components.

The selection of the slack bus option is configurable for each Market Application. Currently, a distributed load slack is used in all Market Application except for the IFM where a distributed load slack is used except in the event that the IFM cannot clear with a distributed Load slack bus in which case it is ran with a distributed generation slack bus.

Lastly, there are two other very important NA functions that are used to produce network sensitivity information required to manage Transmission Losses and Congestion. These are:

- **Power Transfer Distribution Factor (PTDF) Calculations Function** – The PTDF calculations function produces the PTDFs. PTDFs are the sensitivities of injections at any location in the network with respect to flow on any transmission element (in a reference direction). PTDFs are used in the Congestion Management application and the calculation of the LMPs. They are calculated following each AC power flow run.

- **Loss Sensitivity Calculations Function** – The loss sensitivity calculations function calculates the marginal loss factors. These loss sensitivity factors are the sensitivities of Transmission Losses with respect to injection at any network node. Loss factors are calculated following each AC power flow run using the distributed load slack option. Loss factors are accurately calculated for both physical and commercial portions (resource aggregations) of the model. This function also calculates Transmission Losses after each AC power flow run. Transmission Losses are available on a total system basis as well as at each operating entity (e.g., company, MSS and UDC).

2.3 Objective Function

The SCUC engine determines optimally the commitment status and the Schedules of Generating Units as well as Participating Loads and Resource-Specific System Resources. The objective is to minimize the Start-Up and Minimum Load costs and bid in Energy costs and Ancillary Services, subject to network as well as resource related constraints over the entire Time Horizon, e.g., the Trading Day in the IFM. The time interval of the optimization is one hour in the DAM and 5 or 15 minutes in the RTM depending on the application.

In IFM the overall production (or Bid) cost is determined by the total of the Start-Up and Minimum Load Cost of CAISO-committed Generating Units, the Energy Bids of all scheduled Generating Units, and the Ancillary Service Bids of resources selected to provide Ancillary Services. This objective leads to a least-cost multi-product co-optimization methodology that maximizes economic efficiency, relieves network Congestion and considers physical constraints. The economic efficiency of the market operation can be achieved through a least-cost resource commitment and scheduling with co-optimization of Energy and Ancillary Services.

Mathematically, the objective function for the IFM is represented as follows:

$$\min \sum_{h=1}^{T} \sum_{i=1}^{N} \left[\begin{array}{l} SUC_i (1 - U_{i,h-1}) U_{i,h} + MLC_{i,h} U_{i,h} + \int_{P_{\min i}}^{P_{i,h}} C_{i,h}(P_{i,h})\, dP + \\ C_{i,h}^{RU} \cdot RU_{i,h} + C_{i,h}^{RD} \cdot RD_{i,h} + C_{i,h}^{SP} \cdot SP_{i,h} + C_{i,h}^{NS} \cdot NS_{i,h} \end{array} \right]$$

Where

h	Hour index
T	Total number of hours in the time horizon
i	Resource index
N	Total number of resources
$P_{i,h}$	Power output of resource *i* in hour *h*
$RU_{i,h}$	Regulation up provided by resource *i* in hour *h*
$RD_{i,h}$	Regulation down provided by resource *i* in hour *h*
$SP_{i,h}$	Spinning Reserve provided by resource *i* in hour *h*
$NS_{i,h}$	Non-spinning Reserve provided by resource *i* in hour *h*
$C_{i,h}(P_{i,h})$	Cost ($/hour) as a piece-wise linear function of output (MW) for resource i in hour h
$C_{i,h}^{RU}$	Bid cost ($/MW) of regulation up (MW) for resource *i* in hour *h*
$C_{i,h}^{RD}$	Bid cost ($/MW) of regulation down (MW) for resource *i* in hour *h*
$C_{i,h}^{SP}$	Bid cost ($/MW)of spinning reserve (MW) for resource *i* in hour *h*
$C_{i,h}^{NS}$	Bid cost ($/MW) of non-spinning reserve (MW) for resource *i* in hour *h*
SUC_i	Start-Up Cost ($/start) for resource *i*
$MLC_{i,h}$	Minimum Load Cost ($/hr) for resource *i* in hour *h*

$U_{i,h}$ Commitment status; = 0 if resource *i* is off-line, and = 1 if resource *i* is on-line, in hour *h*

Start-Up Cost is occurred whenever a start-up takes place and Minimum Load cost is occurred whenever the unit is online.

Scheduling Coordinators can submit three-part Energy Bids (the three parts are Start-Up Cost in $/start, Minimum Load Cost in $/hr, and Energy Bid Curve above Minimum Load in $/MWh) for Generating Units and Participating Loads. All online units provide Energy service. Some of them can be selected to provide Regulation Up/Down and Spinning Reserve services. Generators can provide Non-Spinning Reserves regardless of their commitment status in the DAM. Costs of Energy Self-Schedules and Self-Provided AS are represented by penalty costs in the objective function. Constraint violations are also represented by penalty costs in the objective function. These penalty terms are not shown in the equation above for simplicity.

Energy and Ancillary Service Bid Costs include integrated Energy Bid Curves. The Energy Bid Curves are stepwise functions of procured services, therefore Bid Costs are piecewise linear functions of service quantities. The minimum segment size is configurable with a default value of 0.01 MW in all cases.

The objective function in MPM is similar to the one in IFM; the submitted Energy Bids are used in both CCR and ACR, whereas the mitigated Energy Bids are used in IFM.

The objective function for the RUC optimization model includes the RUC Availability Bids instead of the Energy and Ancillary Services Bids. For partial RA units, a two segment RUC Availability Bid is acceptable, where the first segment of $0 represents the RA Capacity and the second segment with a bid-in non-zero $ value represents the remaining portion of the unit's capacity.

For RUC, the overall production cost is determined by the total of the Start-Up and Minimum Load Cost of CAISO-committed resources in addition to the ones committed in IFM and RUC Availability Bids of all Scheduled resources. Mathematically, the objective function for the RUC is represented as follows:

$$\min \sum_{h=1}^{T} \sum_{i=1}^{N} \left[SUC_i (1 - U_{i,h-1}) U_{i,h} + MLC_{i,h} U_{i,h} + C_{i,h}^{AV} RU_{i,h} \right]$$

Where:

$C_{i,h}^{AV}$ represents the RUC Availability Bids in ($/MW). Day-Ahead Schedules in RUC are considered as Self-Schedules (i.e., Price Takers) and are represented by penalty costs in the objective function. These penalty terms are not shown in the equation above for simplicity.

The objective function in RTUC is similar to the one in IFM, but the Real-Time Ancillary Services Bids and the mitigated Real-Time Energy bids are used instead. Day-Ahead Ancillary Services Awards are represented by penalty costs in the objective function. The objective function in RTED is similar to the one in RTUC, but without the Start-Up and Minimum Load Costs and without Ancillary Services Bids.

2.4 Input Bids for SCUC Engine

This section describes the various types of Bids that go into SCUC.

2.4.1 Generation Energy Bids

The Generation Energy Bids can include all three cost components:

- Start-Up Cost
- Minimum Load cost
- Energy Bid cost

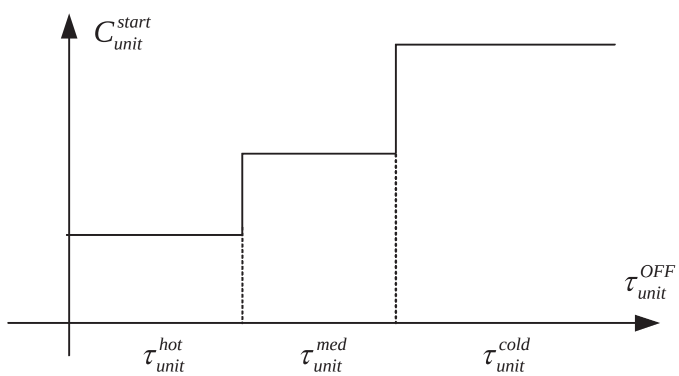
The Start-Up and Minimum Load costs are ignored when the Generating Unit self-commits by submitting Energy Self-Schedules and/or providing Submissions to Self-Provide AS, or when the Generating Unit must be online due to Reliability Must Run requirements or Day Ahead binding commitment and AS awards in RTM. In this case, only the single-part Energy Bid is considered.

The Generation Bids can be submitted in aggregated form associated with Generation Distribution Factors. The aggregated Generation Bids are optimized in aggregated form and resulting Generation Schedules are dis-aggregated to the individual Generating Units using Generation Distribution Factors to perform power flow calculations.

Start-Up Cost Curve:

The Start-Up Cost ($/start) can be dependent on the time passed since the unit was last Shut-Down. This function has a stepwise increasing form across three unit cooling states: hot,intermediate and cold. The typical Start-Up Cost function is illustrated in the following exhibit:

Exhibit A-1: Start-Up Cost Function



The down time is specified in minutes and rounded to the closest time interval in the IFM and to the next time interval in RTM to be a multiple of Market time intervals. The Start-Up Cost curve is treated as unlimited on the right hand side because cooling time is unlimited. Alternatively, the Start-Up Costs can be expressed as a single value not dependent on unit down time.

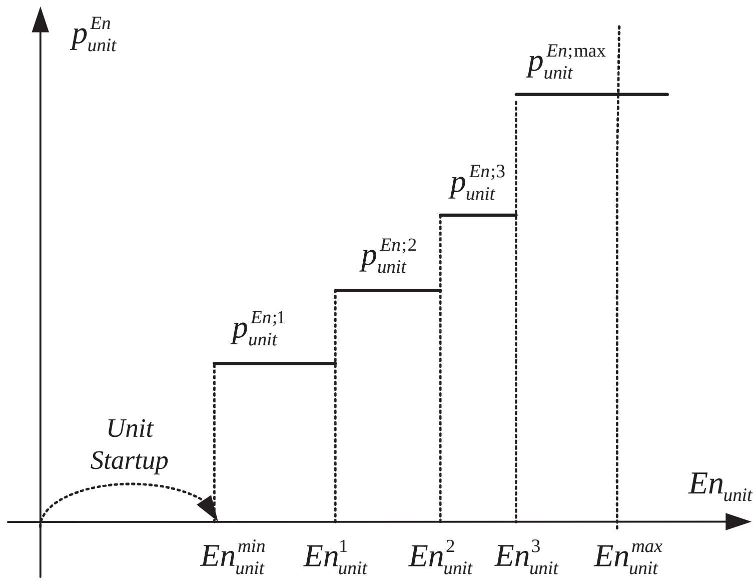
Minimum Load Cost:

The Minimum Load Cost ($/hr) expresses the unit operating costs at the minimum operating point. The Minimum Load Cost is considered whenever a Generating Unit is online.

Energy Bid Cost:

For each Trading Hour a separate Energy Bid Curve and/or Energy Self-Schedule can be submitted. A Generation Energy Bid Curve is a monotonically increasing stepwise function of incremental production cost ($/MWh) versus Energy Generation:

Exhibit A-2: Generation Energy Bid Curve



The integral of the Generation Energy Bid Curve from Minimum Load to the optimal schedule expresses the cost of produced Energy.

Energy Bid Limits:

The starting point of a submitted Generation Energy Bid is the lower economic limit (LEL) and endpoint is the upper economic limit (UEL). The LEL may not be less than the Minimum Load (Pmin) and the UEL may not be greater than the Maximum Capacity (Pmax). Furthermore, if the LEL is greater than Pmin, there must be submitted self-schedules that add up to the LEL.

2.4.2 Load Energy Bids

This section describes the types of load Bids.

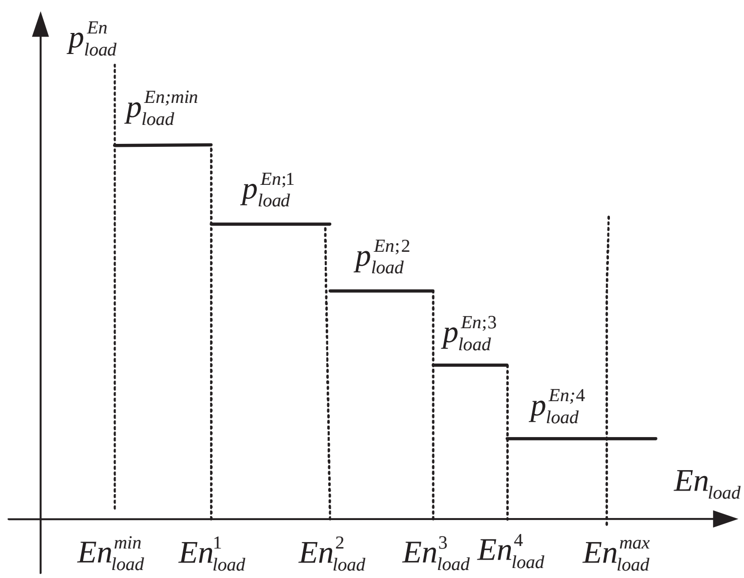
2.4.2.1 Non-Participating Load Bids

Load Single-Part Bid:

Non-Participating Load entities can submit aggregated single-part Energy Bids. These load resources are in online status and dispatched between LEL and UEL according to their Energy Bid Curves. The detailed modeling of the single-part load Bids is as follows.

The aggregated load Bid price curve is a monotonically decreasing stepwise function of incremental benefit ($/MWh) versus Energy consumption:

Exhibit A-3: Load Single-Part Bid



The integral of the load Energy Bid Curve from zero to the optimal schedule expresses the benefit of consumed Energy. This benefit is illustrated in the following exhibit:

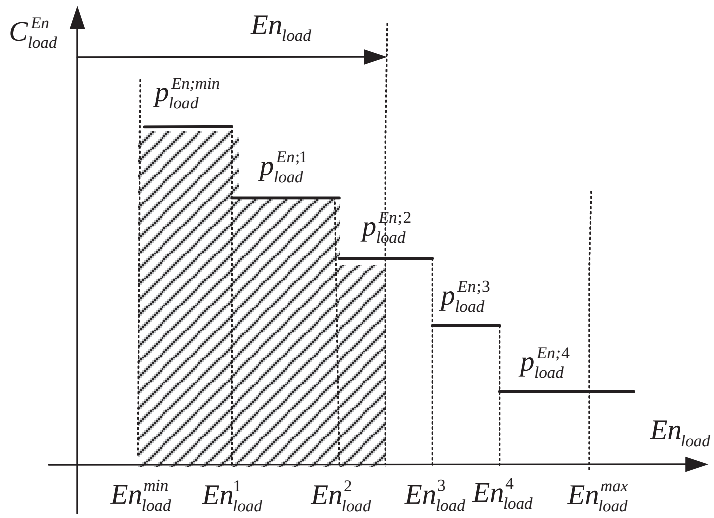


Exhibit A-4: Load Single-Part Bid Benefit

Note that minimum Load costs can be included as a constant part of Demand Bid costs because Non-Participating Load is treated always as online resource.

Load Inter-Temporal and Ramping Constraints:

The Non-Participant Load is considered to be online all the time and inter-temporal constraints are not applicable. Therefore, ramp rate constraints are not formulated for Non-Participating Load.

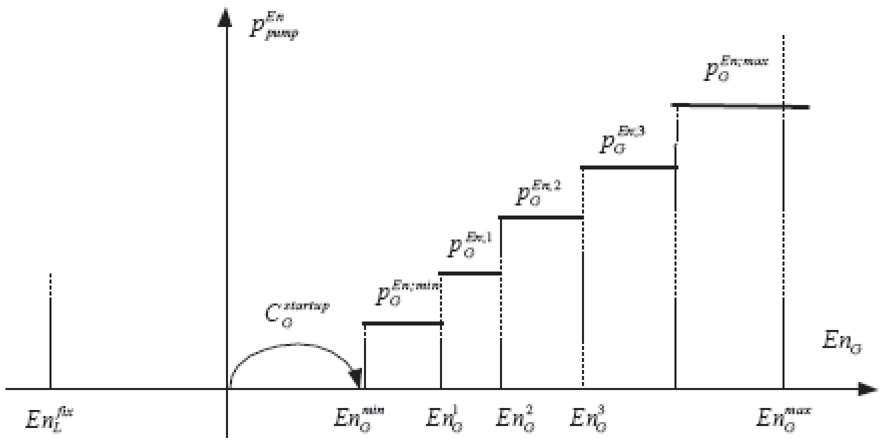
Load Bid Limits:

The starting point of a submitted load Energy Bid is the lower economic limit (LEL) and endpoint is the upper economic limit (UEL). If the LEL is greater than zero, there must be submitted self-schedules that add up to the LEL.

2.4.2.2 Pumped-Storage Hydro Unit Bids

The Pumped-Storage Hydro Units are modeled as a special case of Participating Load Resources. An explicit Pumped-Storage Hydro Unit model is used with three states (offline, pumping, generating) and a three-part bid as follows:

Exhibit A-4: Pumped-Storage Hydro Unit Bid



Where:

En_G	is the generation optimal schedule;
$En_G^{\min}$	is the Lower Economic Limit
En_G^{i}	for i=1,2,…,n; define the segments of the generator energy bid;
$p_G^{En;i}$	for i=1,2,…,n; are the prices of the generator energy bid segments;
En_L^{fix}	is the fixed Pumping Level;
$C_G^{startup}$	is the generator Start-Up Cost;
$C_G^{\min}$	is the generator Minimum Load Cost; and
$C_L^{\min}$	is the Pumping Cost (the cost/hr in pumping mode).

The model includes the ability to provide Non-Spinning Reserve in pumping mode. Inter-temporal constrains apply only to the generating mode, and they are similar to any Generating Resource.

2.4.2.3 Aggregated Participating Load Bids

Aggregated Participating Load is modeled as Aggregated Non-Participating Load in parallel with a pseudo-generating resource.

2.4.3 Ancillary Service Bids

Ancillary Service Costs:

For each Trading Hour separate Bids can be submitted for all Ancillary Services: Regulation Down, Regulation Up, Spinning Reserve and Non-Spinning Reserve. All these services can be provided from zero to Bid maximum MW range with a single service price value. The Ancillary Service costs are calculated using these single segment Bid price curves as follows:

$C_{unit}^{RegUp;t}(RegUp_{unit}^{t}) = p_{unit}^{RegUp;t} \cdot RegUp_{unit}^{t}$ - Generation unit Regulation Up cost

$C_{unit}^{RegDn;t}(RegDn_{unit}^{t}) = p_{unit}^{RegDn;t} \cdot RegDn_{unit}^{t}$ - Generation unit Regulation Down cost

$C_{unit}^{Res;t}(Res_{unit}^{t}) = p_{unit}^{Res;t} \cdot Res_{unit}^{t}$ - Generation unit Spinning Reserve cost

$C_{unit}^{NRes;t}(NRes_{unit}^{t}) = p_{unit}^{NRes;t} \cdot NRes_{unit}^{t}$ - Generation unit Non-Spinning Reserve cost

$C_{load}^{NRes;t}(NRes_{load}^{t}) = p_{load}^{NRes;t} \cdot NRes_{load}^{t}$ - Load Non-Spinning Reserve cost

Where:

$RegDn_{unit}^{t}$ is the Regulation Down Award

$RegUp_{unit}^{t}$ is the Regulation Up Award

Res_{unit}^{t} is the Spinning Reserve Award

$NRes_{unit}^{t}$ is the Non-Spinning Reserve Award

$p_{unit}^{RegDn;t}$ is the Regulation Down Bid price

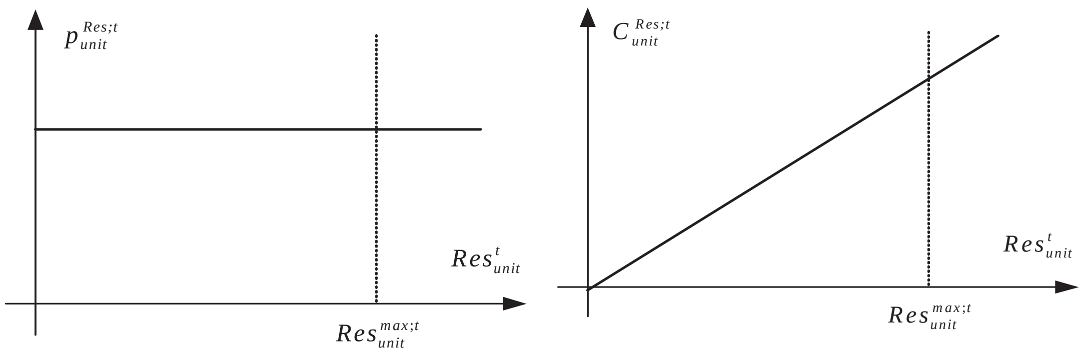
$p_{unit}^{RegUp;t}$ is the Regulation Up Bid price

$p_{unit}^{Res;t}$ is the Spinning Reserve Bid price

$p_{unit}^{NRes;t}$ is the Non-Spinning Reserve Bid price

These Ancillary Service Bid price and cost curves are illustrated on the following exhibits using Spinning Reserve as an example:

Exhibit A-5: Spinning Reserve Bid Price and Cost Curves



Note the cost curve is derived from the submitted single segment bid price.

Ancillary Service Limits:

Each Ancillary Service award is limited by the submitted maximum Bid Quantity (MW). Additionally, the resource ramping capability over the specified ramping time domain is considered as an Ancillary Service award limit. Separate Ramping Rates and ramping time domains can be specified for Regulation, Spinning and Non-Spinning Reserves. The most restrictive of these limits is applied as follows:

$$0 \le RegUp_{unit}^{t} \le \min\{RR_{unit}^{RegUp} \cdot T_{dom}^{Reg};\ \overline{Reg}_{unit}^{Up;t}\};\quad unit \in G; t \in T$$
$$0 \le RegDn_{unit}^{t} \le \min\{RR_{unit}^{RegDn} \cdot T_{dom}^{Reg};\ \overline{Reg}_{unit}^{Dn;t}\};\quad unit \in G; t \in T$$

$$0 \le Res_{unit}^{t} \le \min\{RR_{unit}^{Res} \cdot T_{dom}^{Res};\ \overline{Res}_{unit}^{t}\};\quad unit \in G; t \in T$$

$$0 \le NRes_{unit}^{t} \le \min\{P_{unit}^{\min} + RR_{unit}^{NRes} \cdot \max\left(0, T_{dom}^{NRes} - SUT_{unit}\right); \overline{NRes}_{unit}^{t}\}; \quad unit \in G; t \in T$$

$$0 \le NRes_{load}^{t} \le \overline{NRes}_{load}^{t} \quad load \in L; t \in T\ .$$

Where:

RR_{unit}^{RegUp}	is the Regulating Up Ramp Rate
RR_{unit}^{RegDn}	is the Regulating Down Ramp Rate
RR_{unit}^{Res}	is the Spinning Reserve Ramp Rate
RR_{unit}^{NRes}	is the Non-Spinning Reserve Ramp Rate
T_{dom}^{Reg}	is the Regulation Time Domain
T_{dom}^{ReS}	is the Spinning Reserve Time Domain
T_{dom}^{NRes}	is the Non-Spinning Reserve Time Domain
$\overline{Reg}_{unit}^{Up;t}$	is the Regulation Up bid capacity
$\overline{Reg}_{unit}^{Dn;t}$	is the Regulation Down bid capacity
$\overline{Res}_{unit}^{t}$	is the Spinning Reserve bid capacity
$\overline{NRes}_{unit}^{t}$	is the Non-Spinning Reserve bid capacity
$\overline{NRes}_{load}^{t}$	Is the Non-Spinning bid capacity from a pump

Submissions to Self-Provide Ancillary Service:

Submissions to Self-Provide AS can be submitted in addition to or in place of Ancillary Service Bids. The Self-Provided AS are subject to qualification based on resource Ancillary Service ramping limits and regional requirements. A Qualified Ancillary Service Self-Provision may not be used to satisfy requirements for lower quality Ancillary Services.

2.4.4 Residual Unit Commitment (RUC) Bids

Reliability Capacity:

For each Trading Hour in the DAM, separate Bids can be submitted for RUC Capacity in excess of any submitted RA RUC Obligation as a single segment availability price curve. If a unit is Scheduled in IFM Market run, the RUC Capacity is additional capacity on top of Scheduled Energy in the IFM. If a unit is committed in RUC, the entire RUC Schedule constitutes RUC Capacity.

$$RCap_{unit}^{t} = \max\left(0;\ \Delta En_{unit}^{t}\right); \quad unit \in G; t \in T$$

Where:

Δ-values present quantities scheduled for reliability purposes as increments for generators and decrements (negative values) for participating loads to already Scheduled or self-provided quantities in IFM.

The portion of the RUC Capacity above the IFM Schedule that corresponds to a submitted RUC Availability Bid constitutes a RUC Award and is subject to payment at the relevant RUC LMP. If a resource is committed in RUC, the RUC Award does not include the Minimum Load; the Minimum Load is paid the relevant minimum load cost as part of the Bid Cost Recovery.

The RUC Capacity has a zero cost for the portion that corresponds to the RA RUC Obligation and the single price value is applied only to any additional RUC Capacity that corresponds to the RUC Availability Bid. The RUC Capacity costs are calculated using these single segment Bid price curves as follows:

$$C_{unit}^{RCap;t}(RCap_{unit}^{t}) = p_{unit}^{RCap;t} \cdot RCap_{unit}^{t}$$ - Generation unit cost

Where:

$RCap_{unit}^{t}$ is the RUC Award

$p_{unit}^{RCap;t}$ is the RUC Availability Bid Price

The unit RUC Availability Bid price and cost curves are illustrated on the following exhibit:

Exhibit A-6: RUC Availability Bid Price and Cost Curves

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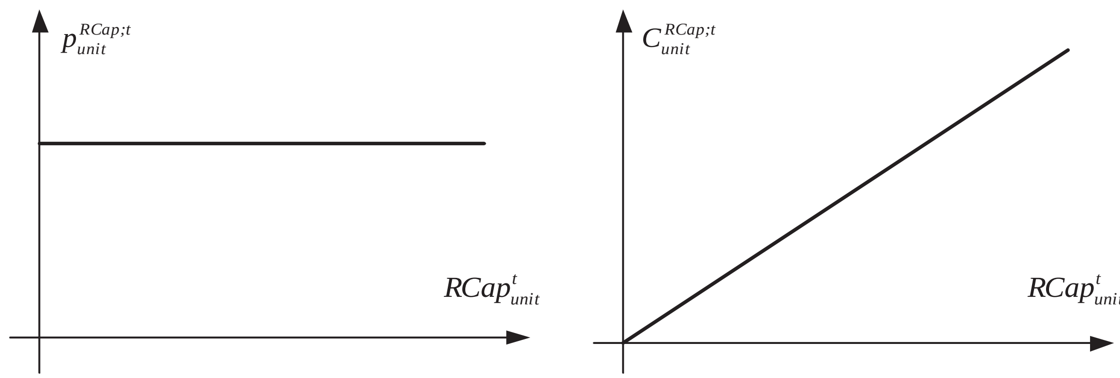


Note the cost curve is derived from the submitted single segment bid price

2.5 Constraints

This section describes the constraints that are enforced by the SCUC process. The constraints in the SCUC optimization include the power balance constraints, Ancillary Service capacity requirement constraints, network constraints under both base case condition and contingencies, and Generating Unit inter-temporal constraints.

2.5.1 Power Balance Constraint

The Power balance constraint states that the Generation in the system should balance out with the load plus the Transmission Losses. Only one market-wide power balance constraint is considered. The Energy balance is enforced by all Market Applications. Both Bid-in Generation and bid-in load (IFM only) or CAISO Forecast (Except IFM) participate in the power balance constraint including network Energy losses:

$$\sum_{unit \in G} En_{unit}^{t} - \sum_{load \in L} En_{load}^{t} = En_{req}^{t} + En_{loss}^{t} \ ; t \in T$$

The Energy loss model is derived from the full AC network solution which is updated during the SCUC-NA iteration process. The network Energy losses are linearized using marginal loss factors α around the base operating point:

$$En_{loss}^{t} = En_{loss}^{base;t} + \Delta En_{loss}^{t} ; t \in T$$

Where:

$$\Delta En_{loss}^{t} = \sum_{unit \in G} \alpha_{node}^{t} \cdot (En_{unit}^{t} - En_{unit}^{base;t}) - \sum_{load \in L} \alpha_{node}^{t} \cdot (En_{load}^{t} - En_{load}^{base;t}) \ ; t \in T \ .$$

Depending on the Market Application, the Energy requirement can present the sum of fixed loads and Generations, system load forecast or actual Energy imbalance:

$$En_{req}^{t} = \begin{cases} En_{LF}^{t} - En_{loss}^{base;t} ; t \in T & Load \ \ Forecast \\ En_{SS}^{t} ; t \in T & Self-Schedules \\ En_{Imb}^{t} - En_{loss}^{base;t} ; t \in T & Energy \ \ Imbalance \end{cases}$$

Note that load forecast and imbalance requirement already include network Energy losses while Energy Self-Schedules present delivered load. The power balance can be expressed in terms of loss penalty factors:

$$\sum_{unit \in G} En_{unit}^{t} / pf_{unit}^{t} - \sum_{load \in L} En_{load}^{t} / pf_{load}^{t} = En_{req}^{t} + \Delta En_{req}^{t} ; t \in T$$

Where:

$$\Delta En_{req}^{t} = En_{loss}^{base;t} - \sum_{unit \in G} \alpha_{node}^{t} \cdot En_{unit}^{base;t} + \sum_{load \in L} \alpha_{node}^{t} \cdot En_{load}^{base;t} \ ; t \in T$$

and loss penalty factors are calculated as follows:

$$pf_{unit}^{t} = 1/(1-\alpha_{node}^{t}) \text{ and } pf_{load}^{t} = 1/(1+\alpha_{node}^{t})$$

Where:

$En_{unit}^{base;t}$ is the Energy schedule of a unit from NA

$En_{unit}^{load;t}$ is the Energy schedule of load from NA

$En_{loss}^{base;t}$ is the Bass System losses from NA

α_{node}^{t} is the Marginal loss rate at the node i.e. change in system losses due to a marginal injection at the node

2.5.2 Ancillary Services Constraints

The Ancillary Services Requirement can be set up on a global, system-wide basis, or on a more granular regional level. The CAISO Operator can specify the AS procurement requirements for each AS Region. These requirements are minimum and/or maximum bounds on AS procurement, both for the overall system and for pre-specified AS Regions. For each hour, the following AS requirement information is published:

- minimum requirements for Spinning Reserve, Non-Spinning Reserve, Regulation Up, and Regulation Down, by AS Region;
- maximum requirement for Regulation Down, by AS Region; and
- maximum requirements for the total of Spinning Reserve, Non-Spinning Reserve, and Regulation Up, by AS Region.

Both Ancillary Service Bids and Submissions to Self-Provide Ancillary Services can be submitted for each Ancillary Service. Additionally, Ancillary Service cascading is supported by the optimization, i.e., a lower quality of Ancillary Service can be substituted by a higher quality of Ancillary Service. Specifically:

- Regulation Up can be used as substitution for both Spinning and Non-Spinning Reserves

- Spinning Reserve can be used as substitution for Non-Spinning Reserve

All AS are procured based on a ramp time of 10 minutes. The cascading sequence is common for all Ancillary Service Regions and all time intervals. Selected Ancillary services Bids are paid the relevant Ancillary Service Marginal Price (ASMP). Qualified Ancillary Service Self-Provision reduces the relevant SC Ancillary Service Obligation for Ancillary Services Cost Allocation. The settlement for the allocation of Ancillary Services costs is system-wide. This means for example that a Load Serving Entity with load in the San Diego LAP can self-provide some or all of its AS Obligation from Generating Units in NP15 if the Self-Provided AS clears the IFM. Section 4.2.1 of Market Operations BPM provide more details about AS self-provision qualification process.

2.5.2.1 Regulation Up and Down Requirements

For each AS Region and each Trading Hour a minimum requirement for Regulation Up capacity and a minimum and maximum requirement for Regulation Down can be specified. Both Regulation Bids and Regulation self-provisions can participate in meeting these requirements. Only online generating units can be awarded Regulation service to meet the Regulation Up and Regulation Down requirements.

Separate minimum requirements for Regulation Up capacitiy can be specified for each Ancillary Service region

$$\underline{Reg}_{ASreq}^{Up;t} \leq \sum_{unit \in AS} Reg_{unit}^{Up;t} \ ; t \in T$$

Separate maximum and minimum requirements for Regulation Down capacities can be specified for each Ancillary Service region:

$$\underline{Reg}_{ASreq}^{Dn;t} \leq \sum_{unit \in AS} Reg_{unit}^{Dn;t} \leq \overline{Reg}_{ASreq}^{Dn;t} \ ; t \in T$$

<u>Reg Up Regional Requirements:</u>

$$\sum_{i=1}^{N} p_{i,t}^{\mathrm{Re}\,gUp} + RLXD_t^{\mathrm{Re}\,gUp} - RLXU_t^{\mathrm{Re}\,gUp} = p_t^{\mathrm{Re}\,gUp}; P_t^{\mathrm{Re}\,gUp;req\min} \leq p_t^{\mathrm{Re}\,gUp} \leq P_t^{\mathrm{Re}\,gUp;req\max}, \quad \forall t$$

RLXD, RLXU – are nonnegative relaxation variables throughout to which the penalties for violation will apply.

Regional Reg UP Slack:

$$-SLCK_{t}^{\text{RegUp\_Spin}} - SLCK_{t}^{\text{RegUp\_Nspin}} + p_{t}^{\text{Re}\,gUp} = P_{t}^{\text{Re}\,gUp;reg\min}, \forall t$$

$SLCK^{RegUp\_Spin}$, $SLCK^{Regup\_Nspin}$ – are the nonnegative amounts of Reg Up that can be cascaded down towards the regional Spin and Non-spin requirements.

2.5.2.2 Spinning Reserve Requirements

Separate Spinning Reserve minimum requirements can be specified for each AS Region and for each Trading Hour. Spinning Reserve requirements can be met by Spinning Reserve Bids and Spinning Reserve self-provisions as well as Regulation Up Bids. Only online Generating Units provide Spinning Reserve service. According to Ancillary Service cascading, Regulation Up can be used as Spinning Reserve after the Regulation Up requirement is met. The substitution of Regulation Up self-provisions for Spinning Reserve is not allowed.

$$\underline{Res}_{ASreq}^{t} + \underline{Reg}_{ASreq}^{Up;t} \leq \sum_{unit \in AS} Res_{unit}^{t} + \sum_{unit \in AS} Reg_{unit}^{Up;t} \; ; t \in T \;.$$

Regional Spin Requirement:

$$SLCK_{t}^{\text{Re}\,gUp\_Spin} + \sum_{i=1}^{N} p_{i,t}^{tmsr} + RLXD_{t}^{tmsr} - RLXU_{t}^{tmsr} = p_{t}^{tmsr}; \; P_{t}^{tmsr:req\min} \leq p_{t}^{tmsr} \leq P_{t}^{tmsr:req\max}, \forall t$$

- note that only the slack (the excess of Reg Up above the requirements) is counted towards the spin.

Regional Spin Slack:

$$-SLCK_{t}^{Spin\_NSpin} + p_{t}^{tmsr} = P_{t}^{tmsr:req\min}, \quad \forall t$$

2.5.2.3 Non-Spinning Reserve Requirements

Separate Non-Spinning Reserve minimum requirements can be specified for each AS Region for each Trading Hour. The Non-Spinning Reserve requirements can be met by Non-Spinning Reserve Bids and Non-Spinning Reserve self-provisions as well as Regulation Up and Spinning Reserve Bids. The cascading of Regulation Up and Spinning Reserve self-provisions is not allowed.

Regional Non-spin Requirements:

$$SLCK_t^{\mathrm{Re}\,gUp\_Nspin} + SLCK_t^{Spin\_Nspin} + \sum_{i=1}^{N} p_{i,t}^{tmns} + RLXD_t^{tmns} - RLXU_t^{tmns} = p_t^{tmns}; P_t^{tmns:req\min} \le p_t^{tmns} \le P_t^{tmns:req\max}, \forall t$$

2.5.2.4 Maximum Upward Capacity Constraint

The total amount of upward Ancillary Service capacity is limited for each AS Region. Specifically, the sum of Regulation Up, Spinning Reserve and Non-Spinning Reserve procured in each AS Region using Bids or self-provisions cannot exceed a limit maximum capacity at any time interval.

$$\sum_{unit \in AS} Reg_{unit}^{Up;t} + \sum_{unit \in AS} Res_{unit}^{t} + \sum_{unit \in AS} NRes_{unit}^{t} + \sum_{load \in AS} NRes_{load}^{t} \le \overline{UCap}_{ASreq}^{t}\ ; t \in T.$$

The Ancillary Service Self-Provisions are qualified if they satisfy the maximum upward regional capacity limit. Otherwise, qualified Ancillary Service Self-Provisions are determined according to the following rules:

- The total qualified Ancillary Service Self-Provisions are adjusted for each Ancillary Service region in order based on pre-specified priorities among these regions
- In each Ancillary Service region, the qualified Ancillary Service Self-Provisions are adjusted to meet regional maximum upward limit in reverse quality order (Non-Spinning Reserve first, followed by Spinning Reserve and then Regulation Up)
- For each Ancillary Service, Ancillary Service Self-Provisions are qualified pro rata to meet regional maximum upward limit

2.5.3 Network Constraints

Network constraints due to Energy Schedules are considered in the optimization for both the base case and contingency cases. The network Power Flow Model is based on a full AC power flow solution performed by Network Application (NA). However, SCUC/SCED models only MW (active) variables where MVAR (reactive) variables are not considered. Therefore in the NA-SCUC iteration process, the branch flow MVA limits are translated into MW limits in SCUC, assuming that MVAR branch flows and voltage magnitudes, as determined in NA, do not change significantly from one iteration to the next. In SCUC, the transmission line flows are expressed as linearized functions of the nodal power injections around the base operating state from NA using calculated PTDFs.

The set of critical transmission lines is selected according to the percentage of line MW loading. The lines loaded above the specified threshold are included in the optimization. To avoid oscillations in the SCUC-NA iteration process, lines are added into and never deleted from the critical set for a complete market process pass. The maximum number of enforced network constraints can be specified by the authorized user. The network constraints are ordered according to their percentage of loading. There are several types of network constraints as described next.

2.5.3.1 Network Branch Power Flow Limits

The network branch AC power flow limits are modeled as MVA ratings. They represent thermal limits of the transmission equipments. Normal and emergency ratings are specified for each branch for operation in normal and emergency conditions. Branch ratings can also be derated for each interval. The default branch rating is included with the EMS network model data imported into SCUC. Derated ratings are retrieved from CAISO Outage Management Tool (COMT) or entered manually by the CAISO Operator. The software selects the default ratings first, then overrides the default values with those from COMT, and finally overrides the COMT ratings with any user-entered values. Values can be adjusted using a percent bias adjustment.

2.5.3.2 Transmission Interface Limits

A transmission interface is a Branch Group or a path that consists of one or more branches. All interties and WECC paths are defined as transmission interfaces. A branch can be a member of multiple Branch Groups. The Branch Group definition is included with the EMS network model data maintained in the FNM, and that definition is also maintained in the Master File. The ratings for Branch Groups are referred to as Operating Transfer Capability (OTC), usually determined by AC power flow analysis, transient stability analysis, voltage stability analysis, and contingency analysis, performed by CAISO Operation Engineers and sometimes involving multiple neighboring Balancing Authority Areas. These ratings are specified in MW, are directional, and can change hourly. These ratings are provided to the Market Applications by Existing Transmission Contracts Calculator (ETCC). Branch Groups only have normal ratings and these ratings are enforced only in the Base case.

Usually these ratings already take into consideration the effects of significant contingencies. The intertie limits used in SCUC are affected by TOR and ETC transmission capacity reservations. CAISO determines the TOR and ETC rights on each transmission interface based on the applicable OTC, considering any Outages or derates, and related information provided by the responsible Participating Transmission Owner (PTO) or TOR party. The transmission interface limit for interties is then determined by reserving unused TOR and ETC capacity for TOR/ETC with applicable physical rights.

The CAISO market applications are capable of enforcing both Transmission Interface OTC and the associated individual branch limits; however because the Transmission Interface OTC is more restrictive, the associated individual branch limits are normally not enforced. The effect of a binding Transmission Interface constraint is to contribute a congestion component on the LMP at a given location equal to the product of the shadow price of that Transmission Interface and its aggregate shift factor at that location. This aggregate shift factor is calculated as the sum of the respective shift factors of the individual branches that compose the Transmission Interface. In the event that a Transmission Interface and one of its constituent branches are simultaneously binding (very unlikely), there are congestion contributions to the LMP from both the shadow price of the Transmission Interface and that of the constituent branch,

2.5.3.3 Intertie Scheduling Limit Energy-AS Constraints

Energy and Ancillary Service Bids compete for the use of inter-ties when their demands for transmission capacity are in the same direction. Ancillary Service imports compete with Energy Schedules on designated interties in the import direction. Moreover, Energy does not provide counter-flow for Ancillary Service when the demands for transmission capacity are in opposite directions, and Ancillary Service does not provide counter-flow for Energy when the demands for transmission capacity are in opposite directions. Finally, no netting is allowed among Ancillary Services. Only one of the intertie constraints may be binding in either direction at any given time.

Consequently, the intertie transmission constraints in the import direction are formulated as follows:

$$\max\left\{0, En_{Imp}^{t} - En_{Exp}^{t}\right\} + Reg_{Imp}^{Up;t} + Res_{Imp}^{t} + NRes_{Imp}^{t} \leq F_{Imp}^{OTC}; \quad t \in T$$

The intertie transmission constraints in the export direction are formulated in a similar way:

$$\max\left\{0, En_{Exp}^{t} - En_{Imp}^{t}\right\} + Reg_{Imp}^{Dn;t} \leq F_{Exp}^{OTC}; \quad t \in T$$

2.5.3.4 Nomograms

A Nomogram is a set of piece-wise linear inequality constraints relating Generating Unit output and transmission interface flows. Only constraints that relate AC branch MW flows and MW Generation having the standard format of single branch or interface constraints are considered in the SCUC. Resource statuses or Ancillary Services cannot be part of the Nomogram model. The Nomogram constraints must be piecewise linear constraints defining a convex set. Nomograms can consist of a family of piecewise linear constraints. The constraint curve is selected prior to the optimization. The following are examples of typical Nomogram variables:

- AC Interface MW Flow vs. AC Interface MW Flow
- AC Interface MW Flow vs. Area MW Generation

The Nomogram constraint presents a single piecewise linear curve relating two or more Nomogram variables.

2.5.3.5 Contingency Constraints

Contingencies are simulated forced Outages of network elements. SCUC performs contingency analysis using the FNM, to recognize network constraints in the commitment and Dispatch of Generating Units. NA provides a facility for definition and maintenance of contingencies.

A defined contingency may involve any modeled element: line sections, transformers, switches, circuit breakers, shunts, synchronous condensers, etc. Generator and load contingencies can also be defined (for monitoring purposes). Equipment Outages can be defined either by the element itself or its associated disconnect device. Contingency definitions can include actions beyond simply “opening” an element; thus, contingency definitions allow for several different possible actions/commands. For example, a single contingency may involve opening a transmission line, closing an alternate switch or line section (automatic load transfer, as in a “flip-flop” arrangement), and/or bypassing a series capacitor/reactor. The sequence of these events are pre-defined in contingencies.

While most contingencies are likely to involve only one or two elements, no single contingency includes more than 50 elements. The contingency application also categorize each contingency into one of several groups (a configurable number of categories). These categories allow any individual contingency to be applied in one or many Market environments (DAM, RTM).

The security constraints corresponding to contingencies (except monitor only contingencies) are enforced in a preventive control mode, i.e., the optimal Schedule is determined such that no security violations are expected to arise if any defined contingency occurs.

2.5.4 Inter-Temporal Constraints

In this Section we present the inter-temporal constraints in more details.

2.5.4.1 Minimum Up Time

Typically, a Generating Unit cannot change its commitment status at every time interval. It must stay online or offline for some minimum time period without changing its commitment status.

The Minimum Up Time (MUT) constraint, specified in minutes, is the minimum amount of time that a unit must stay online between Start-Up and Shut-Down due to physical operating constraints.

In other words, when a Generating Unit is started, it must stay online at least for T_{unit}^{ON} time intervals. Therefore, if a unit is started at time interval *t+1* the following condition is enforced:

$$u_{unit}^{t+1} + u_{unit}^{t+2} + \cdots + u_{unit}^{t+T_{\min}^{ON}} = T_{unit}^{ON}; \quad unit \in G; t \in T$$

2.5.4.2 Minimum Down Time

The Minimum Down Time (MDT) constraint, specified in minutes, is the minimum amount of time that a unit must stay offline after the start of Shut-Down, including Shut-Down time and Start-Up Time. SCUC can commit and decommit units based on economics and consistent with the units' MUT and MDT constraints.

It must stay offline at least for T_{unit}^{OFF} time intervals, and the following constraint is satisfied if a unit is Shut-Down at time interval *t+1*:

$$u_{unit}^{t+1} + u_{unit}^{t+2} + \cdots + u_{unit}^{t+T_{\min}^{OFF}} = 0; \quad unit \in G; t \in T\ .$$

Where:

u_{unit}^{t} is the status of the unit in time interval 't'

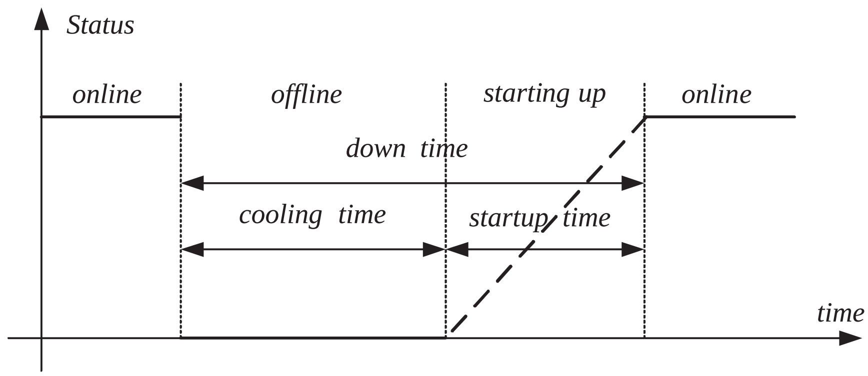
2.5.4.3 Start-Up Time

The Generating Unit Start-Up Time (SUT) is usually dependent on the cooling time, i.e., the time a unit needs to start up depends on how much time the unit has been offline. Therefore, the total down time consists of the cooling time and the Start-Up Time, which is dependent on the cooling time. The total down time is enforced to be no shorter than the MDT.

$$T_{min}^{cool} + T_{unit}^{SUT}(T_{unit}^{cool}) \geq T_{unit}^{OFF}; \quad unit \in G; t \in T\ .$$

The cooling, startup and down time relationship is illustrated on the following exhibit:

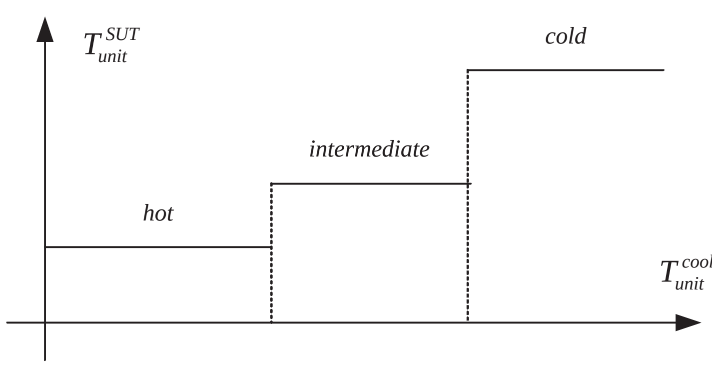
Exhibit A-7: Cooling, Startup, and Down Time



There are three cooling statuses: hot, intermediate and cold. These statuses are presented by separate segments of the Start-Up Time function. These segments are the same as segments of the Start-Up Cost function. The Start-Up Time function is a monotonically increasing staircase curve of Start-Up Cost versus cooling time.

This three-segment function is illustrated in the following exhibit:

Exhibit A-8: Startup Time Function



2.5.4.4 Maximum Number of Daily Start-Ups

Another Generating Unit constraint is related to the maximum number of daily Start-Ups. The total number of daily Start-Ups is limited by a specified number:

$$z_{unit}^{1} + z_{unit}^{2} + \cdots + z_{unit}^{T} \leq N_{unit}^{ON}; \quad unit \in G$$

2.5.4.5 Daily Energy Limits

Energy Limit constraints apply to a prescribed list of Generating Units that can generate limited amount of Energy for a given period of time. Energy-limited Generating Units must indicate an Energy Limit in their DAM Bids that applies to their Schedule and Dispatch throughout the Trading Day. The units are responsible for meeting their Energy Limit requirements for longer time periods, such as weekly, monthly or seasonal, subject to any applicable Resource Adequacy requirements. AS are not constrained by Energy Limits.

The total available Energy can be determined by long-term hydro or fuel scheduling. This limited Energy is optimally distributed over the scheduling period. Environmental limitations (e.g. air emissions etc) is also a reason for a generating unit being energy limited. Furthermore, there could be other non-economic factors as well leading to use-limitation of a resource.

The Energy limit constraint applies to the total energy scheduled or dispatched over the entire time period of each application as follows:

$$\underline{En}_{unit}^{T} \leq En_{unit}^{1} + En_{unit}^{2} + \cdots + En_{unit}^{t} + \cdots + En_{unit}^{T} \leq \overline{En}_{unit}^{T}; \quad unit \in G .$$

In the DAM, the maximum and minimum Energy Limits are obtained from the SIBR Clean Bids. The minimum Energy Limit is negative and applies only to Pump Storage Hydro units.

RTM enforces the Daily Energy Limits as a *dynamically adjusted rolling average* over the course of a Trading Day, providing room for optimal refinement of the DAM Schedules. Aside from the effect of other binding constraints that may conflict with the Energy Limit constraints, the methodology assures a feasible outcome, but only when Dispatch Instructions are followed accurately since the formulation involves only Instructed Imbalance Energy. Consequently, Energy Limits may be violated due to the regulating action of units on regulation and due to uninstructed deviations driving the Dispatch Instructions via the State Estimator feedback. The method would attempt to recover any Energy outside the rolling average limits over the course of a Trading Day; however, this may not be possible if uninstructed deviations persist.

Energy Limits are not enforced in the contingency Dispatch because the Time Horizon is extremely small (10') and the objective of the contingency Dispatch is to recover from a contingency as fast as possible without any regard to Energy limitations over the course of an entire Trading Day.

2.5.5 Ramping Processes

This section describes the effect of Ramping.

2.5.5.1 Operational/Regulating/Reserve Ramp Rate

The Operational Ramp Rate of Generating Units limits the Energy Schedule changes from one time period to the next in SCUC. The Operational Ramp Rate constraints for Energy Schedule changes from one time period to the next are determined by the Operational Ramp Rate function reduced by a configurable percentage of the relevant Regulation Awards in both consecutive intervals, multiplied by a configurable Ramping time domain. In DAM, the ramping time domain is 60min. The ramping time domain is halved at startup and shutdown.

The Operational Ramp Rate function is described by a staircase function of up to four segments (in addition to Ramp Rate segments inserted by SCUC for modeling Forbidden Operating Regions). The Operational Ramp Rate function is submitted with the Energy Schedule and Bid data. The Operational Ramp Rate function allows the SCs to declare the Ramp Rate at different operating levels. However, the submitted Ramp Rate function is fixed throughout the Time Horizon, for which they are submitted (either the 24 Trading Hours, for Day-Ahead, or single hour for the Hour-Ahead). In order to mitigate possible capacity withholding through submitting low Ramp Rates, SCUC uses the same Ramp Rates up as Ramp Rates down. The Ramp Rate changes as soon as the MW output ramps into a different operating level, (i.e., the Ramp Rate does not necessarily remain constant throughout a given range).

Similarly, Regulation Ramp Rate constraints for procurement of Regulation Up and Regulation Down are determined by the submitted Regulation Ramp Rate multiplied by a configurable time interval (currently 10 minutes). The Regulation Ramp Rate (for both Regulation Up and Regulation Down) is described by a single number. The Regulation Ramp Rate is also used to evaluate both Regulation Up and Regulation Down Bids and self-provisions.

Also, the Operating Reserve Ramp Rate constraints for procurement of the Spinning and Non-Spinning Reserves are determined by the submitted Operating Reserve Ramp Rate multiplied by a configurable time interval (currently 10 minutes). The Operating Reserve Ramp Rate (for both Spinning and Non-Spinning Reserves) is described by a single number. The Operating Reserve Ramp Rate is used to evaluate Spinning and Non-Spinning Reserve Bids and self-provisions.

Note that the total amount of upward Ancillary Services is limited by the Generating Unit Ramping capability over a specified time period (default is 10 minutes).

2.5.5.2 Ramping Constraints

The following ramping rules apply consistently for all market applications:

1) The resource's Operational Ramp Rate will always be used to constrain Energy schedules across time intervals irrespective of Regulation Awards. The Operational Ramp Rate may vary over the resource operating range and it incorporates any ramp rates over Forbidden Operating Regions. The fixed Regulating Ramp Rate would only be used to limit Regulation Awards.
2) Hourly intertie resources have infinite ramping capability and market applications follow the ramp capability as provided by the CAS Schedules for these resources.
3) The distinction between fast and slow resources would be eliminated.
4) The upward and downward ramp capability of on-line resources across time intervals would be limited to the duration of the time interval: 60min in DAM, 15min in RTUC, 5min in RTID and RTMD, and 10min in RTCD.
5) The upward and downward ramp capability of resources starting up or shutting down across time intervals (from or to the applicable Lower Operating Limit) would be limited to half the duration of the time interval: 30min in DAM, 7.5min in RTUC, and 2.5min in RTID and RTMD.
6) The upward ramp capability of resources starting up through Fast Unit Start-Up (from the applicable Lower Operating Limit) in RTCD would be limited to the difference between 10 minutes and their Start-Up Time.
7) The upward and downward ramp capability of resources across time intervals would not be limited by capacity limits (operating or regulating limits); in that respect, the upward

ramp capability would extend upwards to +∞ and the downward ramp capability would extend downwards to –∞ by extending the last and first segments of the Operational Ramp Rate curve beyond the resource Maximum Capacity and Minimum Load, respectively. Capacity limits would be enforced separately through the capacity constraints.

8) The upward ramp capability of resources across time intervals with Regulation Up Awards would be reduced by the sum of these awards over these intervals, multiplied by a configurable factor.

9) The downward ramp capability of resources across time intervals with Regulation Down Awards would be reduced by the sum of these awards over these intervals, multiplied by a configurable factor (same as Step 8).

10) By exception, the ramp capability of resources on regulation would not be limited in RTCD.

11) The configurable factor for the upward and downward resource ramp capability reduction would be application specific (DAM, RTUC, RTID and RTMD) because it would depend on the duration of the time interval.

These ramping rules result in a consistent unified treatment across all applications. Conditional ramp limits apply only to resources with Regulation Awards. No ramp capability reduction is required for Spinning or Non-Spinning Reserve Awards given that these awards are normally dispatched by RTCD where all ramp capability must be made available even at the expense of Regulation.

The ramp rate constraints under the simplified ramping approach are as follows:

Online operation: ($U_{t-1} = U_t = 1$)

$$RCD_T(EN_{t-1}) + \alpha_T \left(RD_{t-1} + RD_t\right) \le EN_t - EN_{t-1} \le RCU_T(EN_{t-1}) - \alpha_T \left(RU_{t-1} + RU_t\right) \quad \therefore t = 1,2,\ldots,N$$

Start-Up: ($U_{t-1} = 0 \wedge U_t = 1$, $EN_{t-1} = RD_{t-1} = RU_{t-1} = 0$)

$$EN_t \le LOL_t + RCU_{T/2}(LOL_t) - \alpha_T\, RU_t \quad \therefore t = 1,2,\ldots,N$$

Shut-Down: ($U_{t-1} = 1 \wedge U_t = 0$, $EN_t = RD_t = RU_t = 0$)

$$EN_{t-1} \leq LOL_{t-1} + RCU_{T/2}(LOL_{t-1}) - \alpha_T \, RD_{t-1} \quad \therefore t = 1,2,\ldots,N$$

RTCD Start-Up:

$$EN \leq LOL + RCU_{(T-SUT)}(LOL)$$

With:

$$RCU_T(EN) \equiv \int_0^T ORR(EN)\,dt$$

$$RCD_T(EN) \equiv -\int_0^T ORR(EN)\,dt$$

Where:

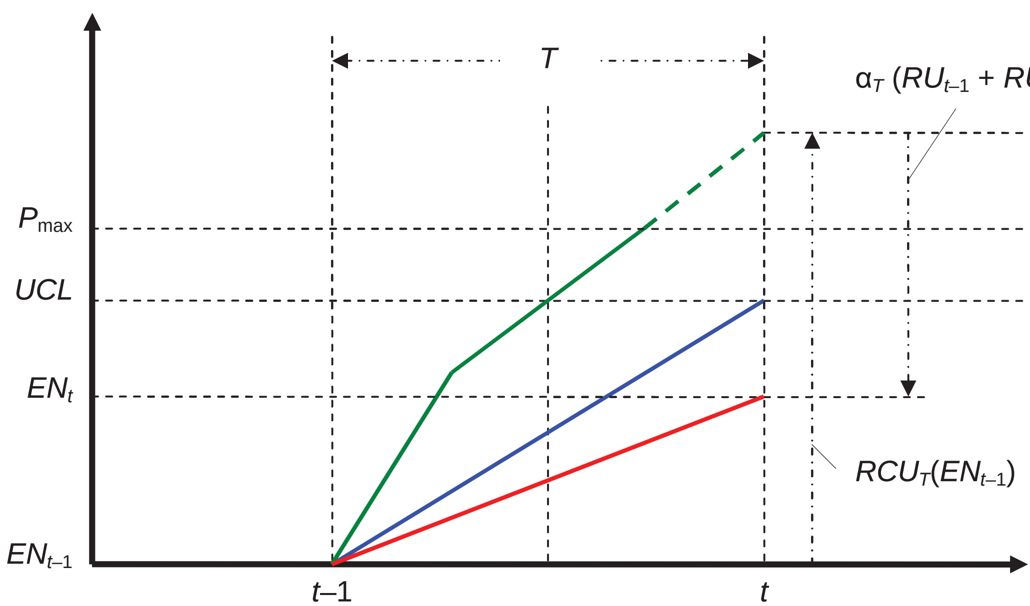
t	is the interval index (zero for initial condition);
N	is the number of intervals in the time horizon;
T	is applicable time domain (60 min in DAM, 15 min in RTUC, 5 min in RTID and RTMD, and 10 min in RTCD);
EN	is the Energy Schedule;
RU	is the Regulation Up Award;
RD	is the Regulation Down Award;
ORR	is the Operational Ramp Rate as a function of the Operating limit, extended below the Minimum Load and above the Maximum Capacity as needed;
RCU	is the upward ramp capability within the applicable time domain as a function of the Operating limit;
RCD	is the downward ramp capability within the applicable time domain as a function of the Operating limit;
LOL	is the applicable Lower Operating Limit
SUT	is the Start-Up Time; and

α is a configurable parameter for the applicable time domain ($0 \le \alpha$).

The default settings for the configurable parameter α are as follows:

DAM	α60' = 3
RTUC	α15' = 0.75
RTID RTMD	α5' = 0
RTCD	α10' = 0 (no ramp capability reduction in RTCD)

The following figure illustrates how the ramp constraints limit the energy schedule of an online resource across time intervals to reserve upward ramp capability for Regulation Up Awards over these intervals.



The green line is the upward unit trajectory at full ramp using the operational ramp rate curve and ignoring any capacity limits. UCL is upper capacity limit in interval t, in this case the lower of the Upper Operating Limit reflecting derates or the Upper Regulating Limit, minus the Regulation Up Award in interval t. Without any ramp capability reduction, the unit may be scheduled as high as the UCL (enforced by the capacity limit constraints). In this case, under the smooth cross-interval ramping requirement, the unit would ramp along the blue line.

However, considering the Regulation Up Awards, the simplified ramping constraints would bind the unit trajectory on the red line, thus reserving upward ramp capability for Regulation Up.

2.5.5.3 Ancillary Services Ramping Constraints

In addition to individual Ancillary Service ramping limits, the common Ancillary Service ramping constraint can be posted for each resource and each time interval. All upward Ancillary Services, i.e. Regulation Up, Spinning Reserve and Non-Spinning reserve can be limited by the resource ramping capability. The Ancillary Service ramping constraints are applicable for online generation units only. These constraints are expressed in time domain as follows:

$$\frac{Reg_{unit}^{Up;t}}{RR_{unit}^{Reg}} + \frac{Res_{unit}^{t}}{RR_{unit}^{Res}} + \frac{NRes_{unit}^{t}}{RR_{unit}^{NRes}} \leq T^{AS}; \quad unit \in G; t \in T$$

having meaning that the total ramping time can not exceed the specified Ancillary Service ramping time (default 10 minutes). These constraints include both Ancillary Service self-provisions and Ancillary Service Bids.

The Ancillary Service procurement can be constrained by resource Energy ramping of slow-ramping resources. These constraints are enforced by the following ramping rules:

- If Energy Schedule is ramping in upward direction more then 20 minutes (configurable) then the resource can not be awarded Regulation, Spinning Reserve or Non-Spinning Reserve) at both hours.

- If Energy Schedule is ramping in downward direction more than 20 minutes (configurable) then the resource can not be awarded Regulation Down at both hours.

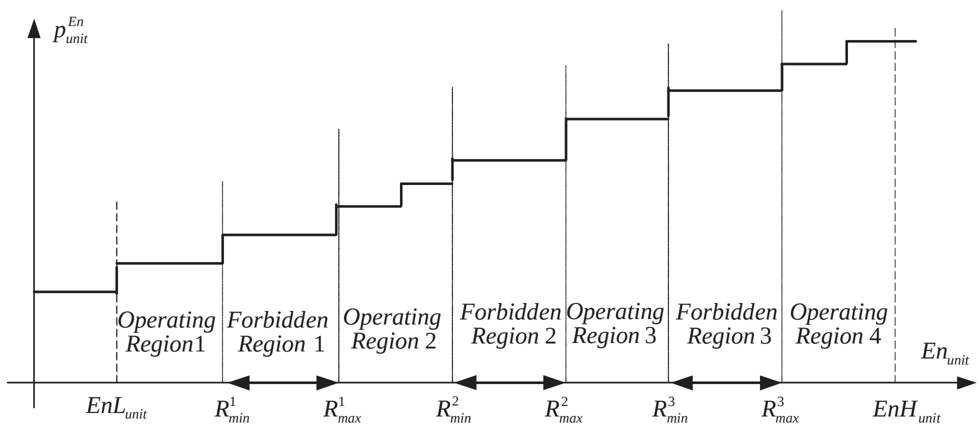
These constraints prevent Ancillary Services awards when the ramping capability of generating units is already fully used for Energy ramping.

2.5.6 Forbidden Operating Region Constraints

The Forbidden Operating Region is specified as a pair of low and high operating levels between which a Generating Unit may not operate in a stable manner. The Forbidden Operating Regions lie between the Generating Unit Minimum and Maximum Operating Limits and they do not overlap. There is a separate Ramp Rate segment for each Forbidden Operating Region, derived by dividing the Forbidden operating Region range with its crossing time. A Generating Unit can have up to four Forbidden Operating Regions.

The forbidden regions are illustrated on the following exhibit:

Exhibit A-9: Forbidden Operating Regions



There are certain rules that the SCUC engine enforces in the DA MPM and IFM while dealing with Forbidden Operating Regions. These rules are:

- If unit can cross the Forbidden Operating Region in less then one time interval then it is never scheduled to operate inside the Forbidden Operating Region.

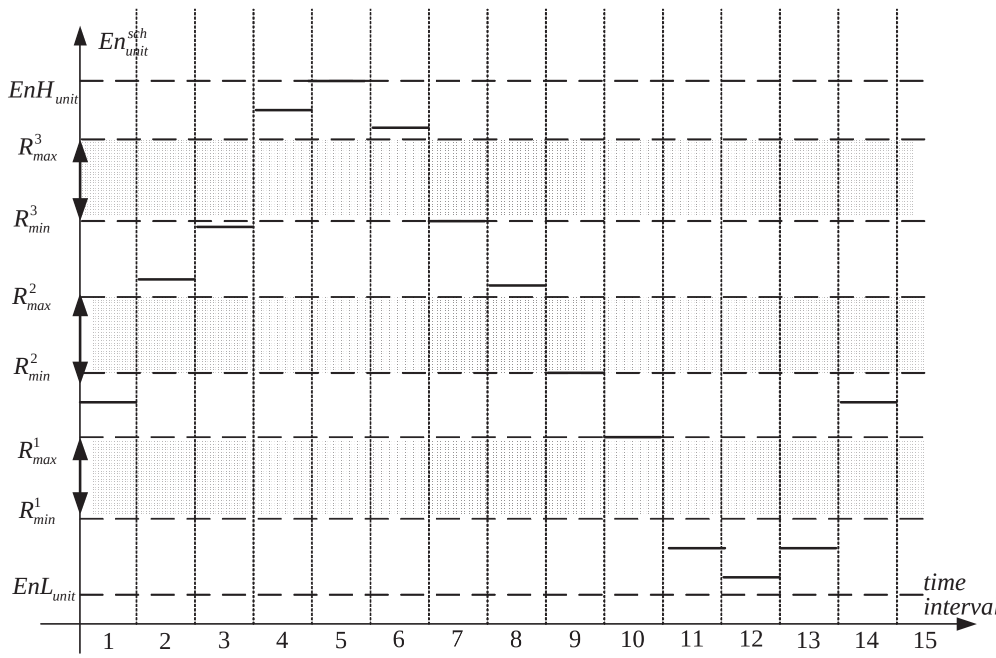
- If a slow unit cannot cross Forbidden Operating Region without stepping inside it, the unit is scheduled to operate with full Ramp Rate inside a Forbidden Operating Region.

- The reversal of crossing direction is not allowed while the unit's Schedule is going through the Forbidden Operating Region. No hold time is modeled, i.e., once a unit crosses a Forbidden Operating Region, the unit is allowed in subsequent intervals to cross back the Forbidden Operating Region without requiring the unit to remain above or below the Forbidden Operating Region for a certain period of time.

- The unit cannot provide Ancillary Services within a Forbidden Operating Region, i.e. if unit is scheduled within Forbidden Operating Region then both downward and upward Ancillary Services are equal to zero.

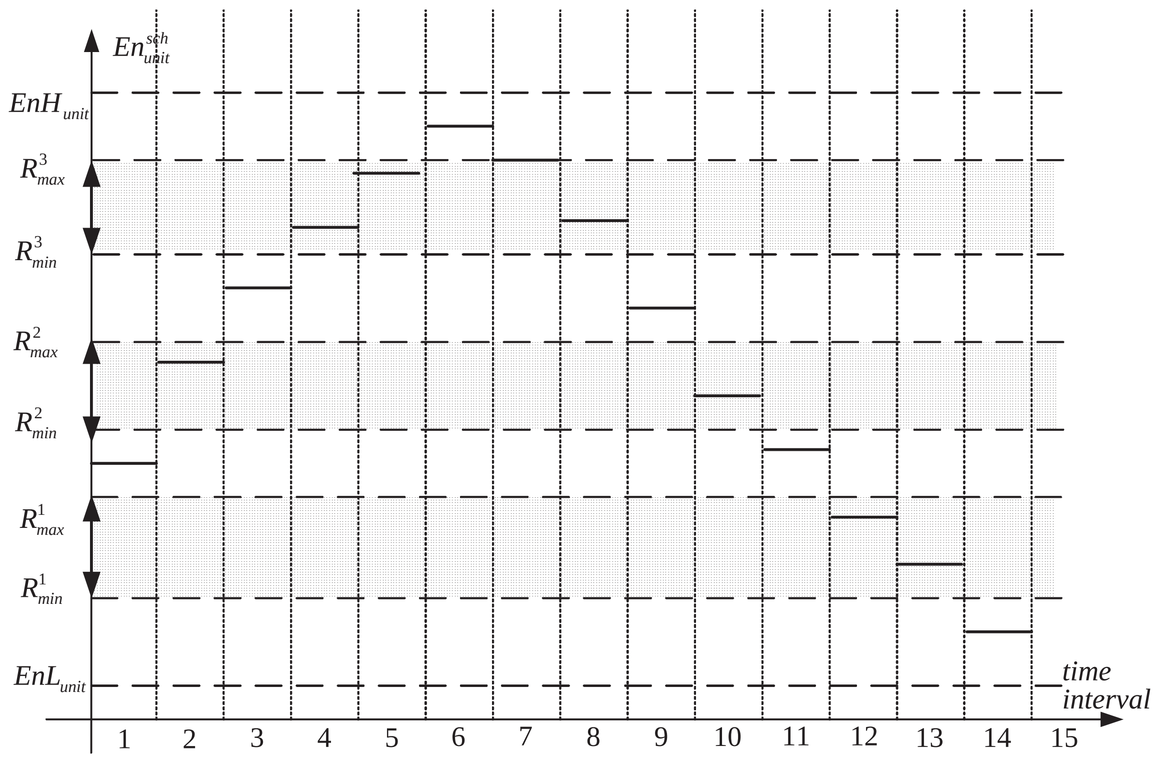
- The unit cannot set the LMP within a Forbidden Operating Region.
- If a unit clears the Forbidden Operating Region in less than 20 minutes, then it is allowed to provide Ancillary Services.
- If unit can cross the Forbidden Operating Region in less then one time interval then it is never scheduled to operate inside the Forbidden Operating Region. The Energy Schedule for this fast unit is illustrated on the following exhibit:

Exhibit A-10: A Fast Unit Energy Schedule



A slow unit can not cross a forbidden region without stepping inside it. In this case the unit is scheduled to operate with full Ramp Rate inside a forbidden region. The Energy Schedule for a slow unit that needs one time interval to cross the second forbidden region and two time intervals to cross the first and the third forbidden regions illustrated on the following exhibit:

Exhibit A-12: A Slow Unit Energy Schedule



2.6 Unit Commitment

This section describes the process for committing units.

2.6.1 Commitment Status

The commitment status for each unit is the On/Off state in each time period. A unit is Off when it is offline or in the process of starting up or shutting down. A unit is On when it is online and synchronized with the grid. An Off-On transition signifies a Start-Up and an On-Off transition signifies a shutdown. The SCUC software categorizes the reasons for which each Generating Unit is committed.

In IFM there are some simple rules that determine the commitment status of a unit. These are:

- If for any interval the unit is offline by SLIC, the unit's mode is set to “unavailable” (U) for that interval.
- If for any interval the unit is forced On by CAISO, the unit's mode is set to “Must Run” (M) for that interval.
- If for any interval the unit has a Self-Schedule, the unit’s mode is set to “Must Run” (M) for that interval.
- If for any interval the unit is forced Off by the CAISO Operator, the unit's mode is set to “Unavailable” (U).
- If a unit is manually scheduled as an RMR unit by the CAISO Operator, its mode is set to “Must Run” (M) in RUC.
- If the unit is determined by the MPM with an RMR requirement, its mode is set to “Must Run” (M) in RUC.
- In all other cases the unit is considered to have a “Cycling” (C) mode in the IFM and its commitment status in each time interval depends on economics and the self-commitment status of the unit.

Additional rules apply in Real-Time to determine the operating mode of the unit:

- If the unit has an Energy self-schedule, its operating mode is set to “Must Run” (M).
- If the unit has a Day-Ahead Regulation or Spinning Reserve Award, its operating mode is set to “Must Run” (M).
- If the unit has a Day-Ahead Non-Spinning Reserve Award and it is not a Fast Start Unit (FSU), its operating mode is set to “Must Run” (M).
- If an online unit has a Day-Ahead Non-Spinning Reserve Award and it is a Fast Start Unit (FSU) with MDT>0, its operating mode is set to “Must Run” (M) (because the non-spin would be unavailable if the unit is cycled off).

- If an online unit has a scheduled binding startup in the future (e.g., a DAM or STUC startup) and the time between the start of the time horizon and that scheduled startup is less than the MDT, its operating mode is set to “Must Run” (M) (because there is inadequate time for cycling off).

An SCUC commitment period is a time span of contiguous hours where a unit’s commitment status is “On” as considered by the SCUC application for the Time Horizon regardless of why the unit is committed. In other words, the SCUC commitment period includes the hours when the Generating Unit is “On” due to self-commitment, manual commitment by CAISO through CAISO Operator action (including certain RMR commitment), and optimal commitment by the SCUC application based on Bid information. The SCUC commitment period extends from a Start-Up to a Shut-Down and it is confined within one Trading Day.

A self-commitment period is a portion of the SCUC commitment period of a unit that has a non-empty Self-Schedule indicating its decision to self-commit the Generating Unit. The self-commitment period may include time periods where the unit does not have a Self-Schedule if it is determined that to meet the Self-Schedule the unit must be On due to MUT, MDT, and MDS constraints.

2.6.2 Boundary Conditions

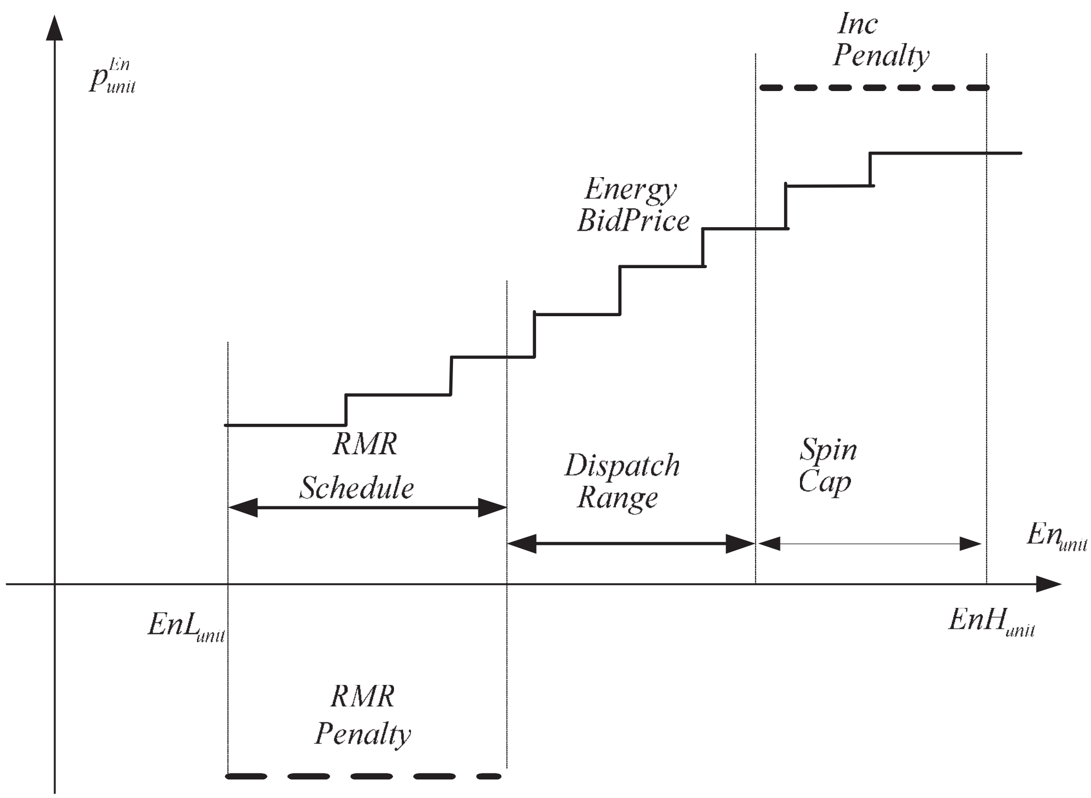
Each run in the IFM for a Trading Day needs to respect certain boundary conditions that result from the outcome of the IFM clearing of the previous day. For example, for a unit that was started up in the last hour of the previous Trading Day and has a Minimum Up Time of six hours, its operating mode is set to “Must Run” (M) for the first five hours of the following Trading Day. Similarly, for a unit that was shut down in the last hour of the previous Trading Day and has a Minimum Down Time of six hours, its operating mode is set to “Unavailable” (U) for the first five hours of the following Trading Day. For these reasons, and because the Start-Up Cost and Start-Up Time are a functions of the cooling time, boundary conditions track the time that a unit has been in a certain state (online or offline).

2.7 Penalty Prices

A Generating Unit may decide to self-commit by submitting a Self-Schedule. The total Self-Schedule of a unit is composed of several specific type of Self-Schedules associated with specific scheduling priorities such as RMR, TOR, ETC, and so on. These Self-Schedules need to be respected by the SCUC engine. One way to achieve this objective is to assign to each specific type of Self-Schedule a penalty price according to its scheduling priority.

The penalty prices express scheduling priorities and have high positive values for incremental adjustments (if applicable) and high negative values for decremental adjustments. If a generating resource has several Self-Schedules at the same time interval, then penalty prices and Self-Schedules are ordered so that the resulting Energy Bid price curve is monotonically increasing. An Energy Bid curve that includes penalty prices is illustrated on the following exhibit:

Exhibit A-11: Energy Bid Curve with Penalty Segments



Note that Inc Penalty covering spin capacity may not be a penalty if the spin is non-flagged as contingency only. If the spin is flagged as contingency only then the spin capacity is currently blocked from energy dispatch unless reserves are activated. If the reserves are activated because of a contingency, then the original bid is used. If the reserves are activated without contingency then the Inc Penalty is used.

In Exhibit A-13, the economic bid that was submitted was replaced with the RMR segment for an RMR requirement.

The SIBR validation process ensures that:

- The sum of all the Self-Schedules for a generating resource must be greater than or equal to the Minimum Load.

- The sum of all the Self-Schedules must be equal to the MW quantity of the first Energy Bid Curve point (if an Energy Bid is submitted) for all resources.

All Self-Schedules are protected from curtailment in the Congestion Management process, if there are other effective Economic Bids that can be used to relieve Congestion. If all effective Economic Bids are exhausted, the Self-Schedules between the Minimum Load and the Energy level of the first Energy Bid Curve point are subject to uneconomic adjustments based on the assigned penalty prices that reflect various scheduling priorities, such as RMR pre-Dispatch, TOR and ETC Schedules, Price Takers, etc. Imports and exports may be reduced to zero; load may be reduced to zero; Generation may be reduced to lower operating (or regulating) limit. Any Schedules below the Minimum Load level are treated as fixed Schedules and are not subject to uneconomic adjustments for Congestion Management.

Furthermore, the SCUC software provides the functionality to classify and prioritize constraints among themselves and the control scheduling priorities discussed earlier. A common system of priority levels is supported for both control and constraint priorities. The priority level for any control or constraint class is configurable. Control and constraint classes may share the same priority level. Currently, all constraints have higher priority (higher penalty prices) than all control priorities.

The scheduling and constraint priorities are presented in Section 6.6.5 of Market Operations BPM.

2.8 Pricing Runs

When the SCUC optimization engine converges, it produces schedules and LMPs for every time interval of the Time Horizon. However, in the event that Generating Units are optimally scheduled or dispatched in the penalty region due to "uneconomic adjustments" required for feasibility, marginal prices reflect the penalty prices of marginal Generating Units scheduled or dispatched in the penalty region. Similarly, if binding constraints are violated for feasibility, marginal prices reflect the penalty prices for these violations.

The solution to this problem requires another run, called the "pricing run," to "filter" these penalty prices out of the dual solution (which produces the prices). Specifically, Generating Units scheduled or dispatched in the penalty region outside their Energy Bid (or their Schedule if there is no Energy Bid) is scheduled or dispatched optimally based on specified configurable priorities, but the appropriate Bid cap is used for pricing purposes.

- For Supply increase or Demand decrease in the penalty region the Energy Bid ceiling (Bid cap) is used.
- For Supply decrease or Demand increase in the penalty region the Energy Bid floor is used.

Also, Generating Units that are not allowed to set the LMP, as identified by a Master File flag (set according to rules stated in Tariff), are also filtered out in the pricing run. Specifically, in the pricing run these Schedules and dispatches are fixed and not re-optimized. The Energy Bid ceiling is used instead of any Bid price greater than the Energy Bid ceiling and the Energy Bid floor is used instead of any Bid price lower than the Energy Bid floor. The Bid caps are configurable and different for Energy and Ancillary Services.

- The Energy Bid ceiling and Energy Bid floor are set currently to $500/MWh and –$30/MWh, respectively.
- The Ancillary Services Bid ceiling and Ancillary Services Bid floor are set currently to $250/MW and $0/MW, respectively.

To maintain consistency between Generating Unit scheduling and commodity pricing, the optimal solution of the scheduling run is preserved in the pricing run to the extent possible. The Generating Unit commitment statuses from the scheduling run are locked in the pricing run, i.e. committed units are “must run” and uncommitted units are “unavailable”. All other constraints are considered in the pricing run.

The optimal Generating Unit Schedules are bounded in the pricing run around the optimal solution of the scheduling run if they are scheduled in the penalty region or at a Bid segment that violates the soft Bid cap (if soft Bid caps exist). These artificial bounds are relatively narrow possible, but large enough to allow a feasible region without creating degeneracy of the optimization model. All other Generating Units, except Constrained Output Generators (COGs), are bounded by their original Minimum and Maximum Operating Limits in the pricing run.

COGs, as identified by a Master File flag, are allowed to set the price in the pricing run if part of their Minimum Load Energy is required to meet Demand. The COGs are allowed to be scheduled continuously between zero MW and their Minimum Operating Limit in the pricing run so that they could set the price at their location if their optimal Schedule turns out to be above zero MW. The Ramping of COGs in the operating region between zero MW and their Minimum Operating Limit is not limited for all time periods of the Time Horizon.

2.9 Energy Pricing

2.9.1 System Marginal Energy Cost

The SCUC co-optimization engine calculates shadow prices as a byproduct of the optimization process. These shadow prices indicate the effect on the objective function of the various constraints. Shadow prices related to the system power balance represent the marginal Energy costs. These shadow prices are the Market Clearing Prices for Energy:

$$MCP^{En;t} = \lambda^{En;t} \; ; \quad t \in T$$

This is known as System Marginal Energy Cost.

2.9.2 Locational Marginal Prices

Load and Generating Unit contributions to the system power balance differ with respect to network Energy losses and eventual transmission congestion. Energy Market Clearing Prices are differentiated according to specific conditions of actual power injections and withdrawals at market participant locations. In general, Energy prices are different at each network node, i.e. they present Locational Marginal Prices. The Locational Marginal Prices for Energy are calculated respecting network losses and eventual transmission Congestion.

The components of Locational Marginal Prices are calculated:

$$LMP_{node}^{En;t} = MCP_{req}^{En;t}$$ - System Marginal Energy Cost

$$+ MCP_{req}^{En;t} \cdot (1 - pf_{node}^{t}) / pf_{node}^{t}$$ - Loss component

$$+ \sum_{line \in N} SF_{line}^{node} \cdot TSC_{line}^{t} \; ; \quad t \in T$$ - Congestion component

Where:

$LMP_{node}^{En;t}$ is Locational Marginal Price for energy at network *node* at time interval *t*

$MCP_{req}^{En;t}$ is market clearing price for energy requirement at time interval *t*

SF_{line}^{node} is shift factor for transmission line and network node

TSC_{line}^{t} is Transmission Shadow Cost for *line* constraint at time interval *t*

All three components of Locational Marginal Price are calculated for each pricing node and each time interval. In an event that a PNode becomes electrically disconnected from the market, LMP at an electrically close PNode is used as the LMP at that location.

This standard definition of Locational Marginal Prices is extended to reflect impact of nomogram constraints. The nomogram price component is calculated as follows:

$$LMP_{node}^{nom;t} = \sum_{line \in NOM} SF_{line}^{node} \cdot ISC_{line}^{t}$$ - Transmission corridor component

Where ISC_{line}^{t} is Interface Shadow Cost for *line* (corridor) at time interval *t*

The Locational Marginal Prices are calculated for aggregated Generation and aggregated Custom Loads directly using aggregated loss penalty factors and aggregated shift factors. These Energy pieces are consistent with the optimal Energy schedules and can be used for settlement of aggregated resources.

2.9.3 Aggregated Energy Prices

To support the settlement process, the Aggregated Market Prices (AMP) are calculated for Aggregated Pricing Locations presenting Default Load Zones, Custom Load Zones and Trading Hubs. The AMPs are calculated in post optimization processing as a weighted sum of Energy Locational Marginal Prices at Pricing Locations belonging to an Aggregated Pricing Location:

$$AMP_{APnode}^{En;t} = \sum_{Pnode \in APnode} w_{Pnode}^{t} \cdot LMP_{Pnode}^{En;t}; \quad t \in T \; .$$

The weighted factors present contribution of individual Energy schedules at Pricing Locations relative to the total Energy schedule at an Aggregated Pricing Location:

$$w_{Pnode}^{t} = \frac{En_{Pnode}^{t}}{\sum_{Pnode \in APnode} En_{Pnode}^{t}}; \quad t \in T .$$

2.9.4 Ancillary Service Marginal Pricing

The marginal cost approach is used for Ancillary Service pricing. According to regional Ancillary Service requirements, the Regional Ancillary Service Marginal Prices (RASMP) are calculated. Separate prices for Regulation Down, Regulation Up, Spinning Reserve and Non-Spinning Reserve are calculated.

The basis for ASMP calculation is shadow costs for minimal and maximal limits for posted Regional Ancillary Service requirements (RASMP). These shadow costs present marginal incremental costs that are calculated as a by-product of the optimization process for each Ancillary Service region. The Ancillary Service requirements are discussed in detail in section 2.5.2.

3 Security Constrained Economic Dispatch (SCED)

SCED is the optimization engine used to run the Real-Time Economic Dispatch (RTED) functions to determine the optimal five-minute Dispatch Instructions throughout the Trading Hour consistent with Generating Unit and transmission constraints within the CAISO Balancing Authority Area. RTED runs every five minutes and utilizes a Time Horizon comprised of up to 13 five-minute intervals, but produces binding Dispatch Instructions only for the first five-minute interval of that Time Horizon. RTED produces LMPs at each PNode that are used for Settlement as described in Section 11.5 of the CAISO Tariff.

3.1 Security Constrained Economic Dispatch Description

The SCED optimization engine determines Energy Dispatch and prices. RTED executes regularly at a Dispatch time before each Dispatch Interval. There is a fixed time delay between each Dispatch time and the following Dispatch Interval. The time delay accounts for the RTED execution time, the Dispatch approval time, and the communication time for Dispatch

Instructions via ADS. The Time Delay is currently set to 5 minutes. The first Dispatch Interval of an hour starts at the start of that hour and the last Dispatch Interval ends at the end of that hour.

3.2 Security Constrained Economic Dispatch Target

The Dispatch Operating Target (DOT) is the optimal Dispatch calculated by RTED based on telemetry. The Dispatch Operating Point (DOP) is the expected trajectory of the dispatched Generating Unit as it responds to Dispatch Instructions taking into account its Ramp Rate capability. DOT is a single point on the DOP trajectory.

3.3 Security Constrained Economic Dispatch Functions

Specifically, RTED performs the following functions:

- Calculate the Imbalance MW requirement for the next Dispatch Operating Target (DOT), which is the middle of the next Dispatch Interval
- Calculate the Dispatch Operating Target for each Participating Generator as the optimal Dispatch for the next DOT to procure the required Imbalance Energy at least cost subject to Generating Unit and network constraints
- Perform a pricing run to determine the Locational Market Prices (LMPs) for the next Dispatch Interval; LMPs are calculated for each PNode and in an aggregate level at LAPs
- Calculate the Dispatch Operating Point (DOP) for each participating Generating Unit as a function of time as the expected trajectory of the Generating Unit operating point subject to Generating Unit capabilities
- Calculate the Ancillary Services capability of participating Generating Units at the start of the next Dispatch Interval based on Generating Unit capabilities, and Ancillary Services Schedules

APPENDIX 2

APPENDIX 2 CONTAINS

CONFIDENTIAL MATERIAL

APPENDIX 3

APPENDIX 3 CONTAINS

CONFIDENTIAL MATERIAL

BEFORE THE PUBLIC UTILITIES
COMMISSION OF THE STATE OF CALIFORNIA

DECLARATION
OF ANDREW SCATES

A.13-05-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 2012, (ii) Costs Related to those Activities Recorded to the Energy Resource Recovery Account and Transition Cost Balancing Account in 2012 and (iii) Costs Recorded in Related Regulatory Accounts in 2012

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, 2012 through December 31, 2012, and (iii) the Entries Recorded in Related Regulatory Accounts. Additionally, as Market Operations Manager, I am thoroughly familiar with the facts and representations in this declaration and if called upon to testify I could and would testify to the following based upon personal knowledge.

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

- that the material constitutes a particular type of data listed in the Matrix;
- the category or categories in the Matrix the data correspond to;
- that SDG&E is complying with the limitations on confidentiality specified in the Matrix for that type of data;
- that the information is not already public; and
- that the data cannot be aggregated, redacted, summarized, masked or otherwise protected in a way that allows partial disclosure.

3. The Protected Information contained in my Testimony constitutes material, market sensitive, electric procurement-related information that is within the scope of Section 454.5(g) of the Public Utilities Code.[1] As such, the Protected Information provided by SDG&E is allowed confidential treatment in accordance with Appendix 1 – IOU Matrix in D.06-06-066.

Confidential Information	**Matrix Reference**	**Reason for Confidentiality**
Section X FOR data	IX.B	Recorded data on specific resources (rather than broad categories of supply sources) used to serve bundled load; Appendix I IOU Matrix does not specify effective period of confidentiality.
Appendix 2 Item 1	V.C	LSE total energy forecast; front 3 years of forecast confidential.
Appendix 2 Item 3	II.A.1	Electric price forecast; confidential for three years.
Appendix 2 Items 2,4, 6, 7	IV.A and B	Forecast of IOU generation resources (not by resource category); confidential for three years.
Appendix 2 Item 5	II.B.1	Generation cost forecast for URG resource confidential for three years.
Appendix 2 Item 8	VI.B	Utility bundled net open position; confidential for the front 3 years.
Appendix 3 all items	IX.B	Recorded data on specific resources (rather than broad categories of supply sources) used to serve bundled load; Appendix I IOU Matrix does not specify effective period of confidentiality.

[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.

4. I am not aware of any instances where the Protected Information has been disclosed to the public. To my knowledge, no party, including SDG&E, has publicly revealed any of the Protected Information.

5. I will comply with the limitations on confidentiality specified in the Matrix for the Protected Information.

6. The Protected Information cannot be provided in a form that is aggregated, partially redacted, or summarized, masked or otherwise protected in a manner that would allow further disclosure of the data while still protecting confidential information.

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

Executed this 20th day of May, 2013, at San Diego, California.

Andrew Scates
Market Operations Manager
San Diego Gas & Electric Company