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STATE OF CALIFORNIA
State Energy Resources
Conservation and Development Commission

In the Matter of:	DOCKET NO: 07-AFC-6
CARLSBAD ENERGY CENTER PROJECT	CENTER FOR BIOLOGICAL DIVERSITY'S RESPONSE IN SUPPORT OF CITY OF CARLSBAD'S MOTION TO TAKE OFFICIAL NOTICE AND THE CENTER'S MOTION TO TAKE OFFICIAL NOTICE AND RE-OPEN THE EVIDENTIARY RECORD

I. INTRODUCTION

The Center for Biological Diversity ("Center") hereby files the following response in support of the City of Carlsbad and Carlsbad Redevelopment Agency's Motion to Take Official Notice ("Carlsbad Motion") pursuant to Cal. Code of Regs., tit. 20 Sec. 1716.5. The Center also makes a Motion to Take Official Notice for documents not currently included in the Evidentiary Record and a Motion to Reopen the Evidentiary Record for those documents not subject to Official Notice. All of these documents contain information that is relevant to the proceeding and address factual errors in the Presiding Member's Proposed Decision ("PMPD") and/or new information relevant to the PMPD. Alternatively, if the Commission denies the request for Official Notice, the Center moves to reopen the Evidentiary Record to include all of the documents discussed in this Response and Motion.

II. ARGUMENT

A. The Commission Should Grant the Carlsbad Motion.

The Carlsbad Motion requests Official Notice of the Application of SDG&E for Authority to Enter into Purchase Power Tolling Agreements with Escondido Energy Center, Pio Pico Energy Center, and Quail Brush Power. (Carlsbad Motion.) The Commission may take Official Notice of any generally accepted matter within its field of competence. (20 Cal. Code Reg. § 1213.) The Public Utilities Commission filings are within the field of competence of the Energy Commission, provide a basis for a No Project Alternative that was not discussed in the PMPD, and demonstrate that the PMPD relies upon a faulty No Project Alternative analysis. (See also Center for Biological Diversity's Comments on the PMPD ("Comments") Sec. I.C.3 & I.D.) Furthermore, SDG&E's Application sets forth new facts that will alter the PMPD's cumulative impacts analysis. (See also Comments at 17-18.)

B. Request to Take Official Notice

The following documents are within the competence of the Energy Commission because they relate to local reliability, the status of reliability-must-run contracts, solar pricing, renewable integration, and use of LNG at the Carlsbad Energy Center Project. Pursuant to California Code of Regulations, title 20, section 1213, the Center respectfully requests the Commission take Official Notice of the following matters:

Exhibit A: CPUC Final Report on the Audit of the Encina Power Plant, December 10, 2010.

Exhibit B: CAISO 2009 RMR/Black Start/Dual Fuel Contract Status

Exhibit C: CAISO 2008 RMR/Black Start/Dual Fuel Contract Status

Exhibit D: CAISO Letter to Mr. Randy Hickok re: RMR status terminated, October 15, 2010

Exhibit E: CAISO 2012 Local Capacity Technical Analysis, April 29, 2011

Exhibit F: SCE Submission of Contracts for Procurement of Renewable Energy Resulting from Renewables Standard Contracts Program, January 31, 2011

Exhibit G: San Diego County Air Pollution Control District Comments on the Air Resources Board May 19, 2010, Public Meeting on Revising the Compressed Natural Gas Fuel Specifications for Motor Vehicles, June 14, 2010.

Exhibit H: CEC West Coast LNG Projects and Proposals at 4, December 2010.

Exhibit I: CAISO Integration of Renewable Resources – 20% RPS, August 31, 2010.

Exhibit J: CAISO Summary of Preliminary Results of 33% Renewable Integration Study – 2010 CPUC LTPP Docket No. R.10-05-006, May 20, 2011.

Exhibit K: CEC News Release "Energy Commission Licenses Two East Bay Power Plants," May 18, 2011.

Exhibits A – D are relevant to the determinations to be made by this Commission because they show that the PMPD relies upon factual errors regarding the reliability must run ("RMR") status of plants in the San Diego area in support of its conclusion that the CECP is necessary in order to displace GHG emissions from these older, less-efficient plants within the electricity system. These documents show that the RMR contract of the Encina plant was released at the end of 2007 and that the RMR contract for South Bay was released at the end of 2010, proving that, in fact, the CECP is not necessary to allow the release of these RMR contracts. (See also Comments Sec. I.C.1.)

Exhibits D and E are also relevant to the determinations to be made by this Commission because they illustrate how the electric system and the assumptions based upon it have changed since the application for CECP was first reviewed and, together with the SDG&E Testimony submitted by the City of Carlsbad, undermine the PMPD's argument that the CECP is needed for local reliability and to allow full retirement of the South Bay and Encina power plants. These documents explain that consumption and generation needs have changed in the San Diego region, that South Bay has already been retired, and that with contracts from expected new generation (which do not include CECP), there will be enough capacity to meet San Diego's local reliability needs and to allow full retirement of the Encina plant prior to the 2017 deadline for compliance with new once-through cooling regulations. (See also Comments Sec. I.C.2.)

Exhibit F is relevant to the determinations to be made by this Commission because in the proposed decision the PMPD concludes that "alternative technologies are not capable of meeting the project objectives" (PMPD Alternatives at 18) and dismisses the most promising of these alternatives – rooftop solar PV, which the PMPD admits is technically capable of providing all of San Diego's peak energy needs – as being too expensive to compete with a project like CECP. (*Id.* at 14-15.) However, Exhibit F shows that, contrary to these claims, utility-scale rooftop solar projects are cost effective and one southern California utility is entering into contracts for 250MW worth of rooftop PV for less than the cost of a facility like CECP. (See also Comments Sec. I.C.6.)

Exhibits G and H are relevant to the determinations to be made by this Commission in that they show that LNG use in the San Diego region is not, as the PMPD asserts, speculative. (PMPD GHG at 15.) LNG use in San Diego has been occurring for some time and is likely to ramp up significantly (to near 100 percent) in light of recent actions by the California Air Resources Board. This reasonably foreseeable scenario must be analyzed as part of the environmental review. (See also Comments Sec. I.C.5.)

Exhibits I and J are relevant to the determinations to be made by this Commission because they undermine the PMPD's main argument that the CECP is necessary for the integration of renewables. These documents show that, in fact, the California ISO has determined that the existing fleet provides sufficient operational flexibility to reliably integrate renewables for the 20 percent RPS goal and will likely be sufficient to meet the 33 percent RPS goal as well. These documents counter the assertions made in the PMPD that more gas-fired generation is needed as more renewables are added to California's electricity system. (See also Comments Sec. I.C.4.)

Exhibit K is relevant to the determinations to be made by this Commission because it identifies two newly approved power plants that were not considered in the cumulative impacts analysis in the PMPD. (See also Comments at 18.)

C. Alternatively, the Commission Should Reopen the Administrative Record to Include All Documents Discussed in Sections A and B.

By taking Official Notice of Exhibits A – K, those documents become part of the Evidentiary Record. As discussed above, each of the documents contains information that shows that the PMPD rests parts of its analysis on factual errors. Alternatively, if the Commission does not take Official Notice of all or some of Exhibits A – K and grant the Carlsbad Motion, the Commission should grant the motion to reopen the evidentiary record and allow the inclusion of this information in order to have a final decision that is predicated on accurate statements that inform the public and decision makers about the environmental effects of the project. (See Cal. Public Resources Code § 21000 et. seq.)

The Center also moves to reopen the administrative record to include:

Exhibit L: January 6, 2011 Unified Port of San Diego article "South Bay Power Plant Ceases Operations."

Exhibit M: May 20, 2011 Unified Port of San Diego article "Update on South Bay Power Plant Removal."

Exhibit N: February 1, 2011 Clean Technica article "SCE Buys 20 Years of Solar Power for Less than Natural Gas"

Exhibit O: February 8, 2011 Renewable Energy World article "Solar PV Becoming Cheaper than Gas in California."

Exhibit P: San Diego Union Tribune article "Gas from afar pollutes here, critics say"

Exhibit Q: "Mexico's Costa Azul re-exports first LNG cargo," Platts, January 10, 2011.

Facts in each of these articles undermine the veracity of certain statements or findings in the PMPD. Facts in Exhibits L and M are relevant to the determinations to be made by this Commission because they further undermine the PMPD's conclusion that the CECP was needed for the retirement of the South Bay power plant, which has already been shut down. (See also Comments Sec. I.C.2.) Exhibits N and O are relevant to the determinations to be made by this Commission because they highlight the cost-effectiveness of rooftop solar PV in stories regarding SCE's new 250MW-worth of rooftop solar contracts for below market price referent. (See also Comments Sec. I.C.6.) Exhibits P and Q are relevant to the determinations to be made by this Commission as they further illustrate that LNG use in San Diego is not speculative. (See also Comments Sec. I.C.5.)

Due process requires that the Commission consider the information in Exhibits A-Q and in the Carlsbad Motion documents. (See Cal. Code of Regs., tit. 20 § 1754(b) [(the commission shall consider additional evidence at the hearing if "due process requires"].) Factual errors in the decision also require consideration of this information. (See Cal. Code of Regs., tit. 20 § 1720 [a petition for reconsideration can set forth "an error in fact"].)

III. CONCLUSION

For the foregoing reasons, the Center respectfully requests that the Commission grant this motion and include all the documents discussed in the Response and Motion in the proceeding's evidentiary record.

DATED: June 8, 2011

William Rostov

William B. Rostov
Earthjustice
Attorney for Center for Biological Diversity

EXHIBIT A

Docket No. 07-AFC-6

CENTER FOR BIOLOGICAL DIVERSITY'S RESPONSE IN SUPPORT OF CITY OF CARLSBAD'S MOTION TO TAKE OFFICIAL NOTICE AND THE CENTER'S MOTION TO TAKE OFFICIAL NOTICE AND RE-OPEN THE EVIDENTIARY RECORD

FINAL REPORT ON THE AUDIT OF THE ENCINA POWER PLANT

CONDUCTED UNDER GENERAL ORDER 167
TO DETERMINE COMPLIANCE WITH
OPERATION, MAINTENANCE, AND LOGBOOK STANDARDS

ELECTRIC GENERATION PERFORMANCE BRANCH
CONSUMER PROTECTION AND SAFETY DIVISION
CALIFORNIA PUBLIC UTILITIES COMMISSION
505 VAN NESS AVENUE
SAN FRANCISCO, CA 94102

December 10, 2010

Richard W. Clark, Director
Consumer Protection and Safety Division

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EXECUTIVE SUMMARY

This is the Final Report on the August 2008 audit of the Encina Power Plant ("Encina" or "the plant") prepared by the Commission's Consumer Protection and Safety Division (CPSD). CPSD audited the plant for compliance with the California Public Utilities Commission's ("CPUC's" or "Commission's") General Order 167, which includes Operation, Maintenance, and Logbook Standards for power plants.

In June 2008, CPSD notified Encina of the audit and requested pertinent documents. CPSD visited the plant site in August 2008 in order to observe plant operations, inspect equipment, review documents, and interview plant staff. From these activities, CPSD evaluated whether the plant needed improvements in operation or maintenance policies and whether the plant's programs and procedures met various Operation, Maintenance, and Logbook Standards.

CPSD found 16 violations[1] of Operation and Maintenance Standards. In September 2009, CPSD sent Encina a Preliminary Audit Report which discussed all 16 violations and requested the plant to submit a Corrective Action Plan (CAP). In October 2009, the plant submitted a CAP to address CPSD's concerns on the violations. In March 2010, CPSD held a teleconference with Encina to discuss the plant's CAP and requested the plant to submit more supporting documents. In April 2010, the plant submitted supplemental data to address CPSD's outstanding concerns on the violations. CPSD held a meet-and-confer meeting with Encina on June 22, 2010 to resolve five remaining violations. CPSD now issues this Final Audit Report.

[1] The term "violation" as used in CPSD's Final Audit Report refers to conditions or events where auditors determined that the facility failed to meet G.O. 167 standards. Identification of conditions or events as "violations" in this Final Audit Report does not constitute a formal determination of a G.O. 167 violation by the CPUC. A definitive finding of a G.O. 167 violation requires a formal Commission enforcement proceeding.

INTRODUCTION

In August 2008, a team from the Consumer Protection and Safety Division (CPSD) of the California Public Utilities Commission ("CPUC" or "Commission") audited the Encina Power Plant ("Encina" or "the plant") to determine whether the plant was in compliance with General Order (GO) 167, which includes Operation, Maintenance, and Logbook Standards for power plants.

The team first notified Encina of the audit on June 24, 2008 and requested pertinent documents. The team consisted of Ben Brinkman, Alan Shinkman, and Rick Tse. During the site visit from August 18 to 22, 2008, the team observed plant operations, inspected equipment, reviewed documents, and interviewed plant staff. The team found 16 violations of Operation and Maintenance Standards.

In September 2009, CPSD sent Encina a Preliminary Audit Report which identified the 16 violations and asked the plant to submit a Corrective Action Plan (CAP). In October 2009, the plant submitted a CAP to address CPSD's concerns on the violations. In March 2010, CPSD held a teleconference with Encina to discuss the plant's CAP and asked the plant to submit more supporting documents. In April 2010, the plant submitted additional documents to address CPSD's outstanding concerns. CPSD subsequently held a meet-and-confer meeting with Encina on June 22, 2010 to resolve five remaining violations. The violations and their final outcome and follow-up are detailed in Section 2 and summarized below:[2]

Finding 2.1 Encina failed to inspect and monitor flow-assisted corrosion in high-energy pipes and components. Over time, corrosion wears down pipe walls, particularly at elbows, bends and flow restrictions. If high-energy pipes rupture, they will release high pressure steam and potentially damage equipment, and injure or kill workers. In response, the plant stated that it has conducted periodic spot inspections on both Units 4 and 5 to monitor flow-assisted corrosion. Spot inspections, however, do not qualify as full inspections. The plant cannot fully address the risks of corrosion without a full inspection. Although the plant has conducted more spot inspections in April 2010, the plant should do a full inspection as soon as possible and to develop a formal inspection program. The plant stated that it has allocated more funds toward FAC inspection in next year's budget. The plant will also develop a Piping Assessment Program pursuant to NRG's corporate directive. The program will identify and establish inspection method, location, and frequency. CPSD will inspect Encina and request additional data to determine if the program addresses the risks of high-energy pipe corrosion.

[2] Unless specified otherwise, CPSD auditors made these findings based on plant conditions at the time of the site visit, and information obtained pursuant to data requests. Actual plant conditions may have changed since the time of the site visit.

Finding 2.2 Encina delayed repairs on Unit 4’s high pressure steam turbine, through which high pressure and temperature steam flows. This steam inflicts serious wear and tear on components along its path, particularly on stator vanes and rotating blades. Over time, its components corrode, erode, and undergo metal fatigue and creep. If turbine blades crack, fail, and fly through the turbine, they can cause serious damage and shut down the plant for many months. In response, the plant explained that it deferred the repairs because the recommendation to do so was based on old operating characteristics. Since the recommendation, the number of operating hours and starts has decreased significantly. The steam turbine also runs mostly at low loads and subject to lower pressure and temperature steam. The plant, therefore, extended the repair interval. Nonetheless in February 2010, the plant overhauled Unit 4's HP steam turbine. No further corrective action is required.

Finding 2.3 The plant failed to evaluate or establish a schedule to complete safety improvements that would reduce the plant’s exposure to fires. A fire can injure or kill workers and damage equipment that may shut down the plant for many months. In response, the plant completed several safety recommendations to reduce fire risks. The plant also declined several other recommendations, but provided reasonable justification for its decision. See Finding 2.3 in Section 2 for details.

Finding 2.4 The plant’s Emergency Response Plan (ERP) lacks information on how to respond to earthquakes and wildfires, lacks information on what steps the plant should take after an emergency, and failed to assign certain emergency duties in case of a fire. Emergencies occur without warning. Without proper planning and procedures, the plant cannot effectively respond to emergencies. In response, the plant updated is ERP accordingly. No further corrective action is required.

Finding 2.5 Encina lacks a procedure for processing work orders in its new work management database. Encina still uses the procedure prepared for a database it no longer uses. An updated procedure would explain how the plant initiates, tracks, plans, and schedules work orders, and draw a clear line of responsibility for staff. In response, the plant explained it was transitioning to a new work management database during the audit. And that the new and old databases share similar workflow process. The lack of a procedure for the new database would not have impeded work order planning. The plant explained that it has since completed the transition and fully trained its staff on the new system; therefore CPSD requires no further corrective action.

Finding 2.6 The plant failed to follow its root-cause procedure when it investigated a November 2006 outage when an expansion joint failed. A root-cause analysis (RCA) is a systematic way to identify the ultimate causes of failures to prevent recurrence. Failure to conduct systematic investigations can lead to misdiagnosis and improper correction. In response, the plant explained that the RCA for the November 2006 incident was done per the old procedure. Since July 7, 2008, the plant has adopted a newer and more detailed procedure that governs how staff conducts RCA. In April 2010, the plant submitted a RCA investigation which conformed to the new procedure. No further corrective action is required.

Finding 2.7 The lead operator could not explain the function of a digital display, or why the display was tagged out. The lead operator takes charge in the control room and therefore should know the function and status of controls at all times. This lack of awareness compromises operational reliability and workers' safety. In response, the plant explained that the lead operator at the time did not understand the auditor's question. The auditor's intent, however, was to test how well a lead operator knows his or her controls. Nonetheless, in October 2009, the plant had retrained its operators on this system, which is used to control Unit 4's SCR. No further corrective action is required.

Finding 2.8 The plant has two conflicting black-start test procedures. The plant uses the procedures to test whether the gas turbine can black-start the steam units. The conflicts may confuse staff and cause test errors or inconsistent test results. In response, the plant explained that one of the procedures is a corporate-wide procedure and the other is a plant-specific standard operating procedure. The two procedures work in conjunction with each other. However, the fact that two procedures exist for the same thing may confuse staff. CPSD asked and the plant added a note to cross-reference the two procedures. No further corrective action is required.

Finding 2.9 The plant delayed repairs on its circulating water tunnel. The deteriorating tunnel poses safety risks for workers, and could shut the plant down. Falling concrete can injure or kill workers who go inside to clean and inspect the tunnel. While walking atop the tunnel, operators on routine inspections can trip and fall over deteriorating concrete and uneven walk surfaces. In response, the plant provided pull-test records on Unit 4's tunnel that were conducted in 2006. The records indicated that the tunnel is structurally sound and in good condition. The plant also provided documents to show that it cleaned and inspected all four tunnels in 2009. In regards to surface de-lamination atop the tunnel, the plant made multiple repairs, and erected orange cones and barrier tapes as mitigating measures, where necessary. The plant also agreed to add inspection requirements to its tunnel cleaning procedures and checklists. No further corrective action is required.

Finding 2.10 The plant delayed repairs on a recirculation fan bearing. The defective bearing registered higher than normal operating temperature and could fail. If the bearing fails, it will take the recirculation fan out-of-service and limit the unit's power output. In response, the plant explained that the outboard seal on the re-circ fan failed and not the bearing. On October 29, 2008, the plant repaired the outboard fan seal via Work Order #08-282124. No further corrective action is required.

Finding 2.11 The plant delayed repairs on asbestos-laden insulation. Inhaled asbestos can cause cancer. Also, damaged insulation exposes hot pipes, which can burn workers. In response, the plant analyzed the insulation to confirm it did not contain asbestos. To mitigate burn risk hazards, the plant repaired the broken insulation. No further corrective action is required.

Finding 2.12 The plant delayed high-priority repairs to an oil leak onto hot piping, moisture removal equipment for instrument air, and a defective flood-chamber valve. In response, the plant explained that those repairs are not high-priority repairs because the deficiencies posed no imminent safety hazards. However, operators apparently designated the work orders a priority five, the highest priority in the work order system. At CPSD's request, the plant retrained its staff on work order priority in June 2010. All personnel who enters, prioritizes, and approves work orders attended the training. No further corrective action is required.

Finding 2.13 The plant lacks a knowledge retention program. If senior staff retire in the near future, they will take away with them detailed and valuable knowledge about operation and maintenance. Without a program to retain and transfer institutional knowledge to other staff, upcoming retirements may affect the plant's operation. In response, the plant stated that in 2007 it filled six "transition positions", which are positions filled early on to replace outgoing employees. At the meet-and-confer meeting, the plant explained that knowledge retention is only critical for positions in operations and instrumentation and control. In that regards, the plant has an extensive training and certification program for those positions, which includes mentoring, skill assessment, written and hands-on tests. In addition, experienced operators are often involved in many levels of work processes, such as creating checklists and work procedures to capture institutional knowledge. CPSD requires no further corrective action.

Finding 2.14 The plant failed to post evacuation maps and signs throughout the facility. Contractors or new employees who are unfamiliar with the plant's layout may become disoriented in emergencies and face unnecessary risks; such confusion may slow the plant's response to the emergency. In response, the plant posted evacuation maps and added more exit signage. The plant marked exit pathways with luminescent tape. The plant also placed warning signs at doors and stairways that are ***not*** exit paths. No further corrective action is required.

Finding 2.15 The plant failed to maintain an attendance list at one of the assembly areas. In an evacuation, the safety manager uses the attendance list at the assembly area to take roll call. Without an attendance list, the safety manager cannot accurately account for onsite staff. This may slow the plant's response to an emergency. In response, the plant updated all attendance lists at each of the assembly areas in July 2009. CPSD asked and the plant created a recurring work order to update the attendance list on a regular basis. No further corrective action is required.

Finding 2.16 The plant failed to label critical system components to identify what equipment belongs to which unit; doing so may help operators orient and familiarize themselves with the equipment which they operate, and prevent operational errors. In response, the plant started labeling critical system components. The plant has already labeled about 84% of all valves in all units. The plant has also labeled about 80% of its feedwater system components, which include feedwater heaters. CPSD asks that by April 13, 2011, the plant reports on the progress of its labeling effort.

POWER PLANT DESCRIPTION

Encina Power Plant is located next to the Coastal Highway in Carlsbad, California, about 32 miles North of San Diego. San Diego Gas and Electric (SDG&E) built the plant in the 1950s and operated it until 1999. In May 1999, after California restructured the electric industry, SDG&E sold the plant to Cabrillo Power, a joint venture between Dynegy and NRG. In March 2006, NRG acquired Dynegy's interests in Cabrillo Power and now wholly owns and operates Cabrillo Power.

Photo 1. Encina Power Plant as seen from Carlsbad Boulevard.

The 965-megawatt plant has six generation units; all but Unit 6 are conventional steam units. Units 1, 2, and 3, built in the 1950s, generate 106, 104, and 110 megawatts, respectively. Units 4 and 5, built in the 1970s, generate 300 and 330 megawatts, respectively. The plant also has a 15-megawatt gas turbine. All six units can burn either natural gas or fuel oil, though they typically use the former due to air quality regulations. The plant's 138-kV and 230-kV switchyards deliver the plant's power to the grid.

Table 1. Encina Power Plant has five steam units and one gas turbine unit.

	Year Built	Capacity (megawatts)[3]	Primary Fuel	Backup Fuel
Unit 1	1954	106	Natural Gas	Number 6 Fuel Oil
Unit 2	1956	104	Natural Gas	Number 6 Fuel Oil
Unit 3	1958	110	Natural Gas	Number 6 Fuel Oil
Unit 4	1973	300	Natural Gas	Number 6 Fuel Oil
Unit 5	1978	330	Natural Gas	Number 6 Fuel Oil
Gas Turbine	1968	15	Natural Gas	Diesel Fuel

Unlike most power plants, Encina houses its steam units inside a building. The building protects the units from corrosive sea air and hides the plant's industrial-scale equipment, which some find unaesthetic. Flue gas from all five units exhausts through one smoke stack. The units also share one water intake, which channels seawater from the Agua Hedionda Lagoon to the condensers for cooling. Every two years, the plant dredges the Lagoon to prevent sediment from restricting water flow into the intake structure.

The gas turbine unit is located outside the power plant building. It is of an aero-derivative design; in other words, it closely resembles jet engines used on aircrafts. Although the gas turbine is cheaper to construct than the steam units, it is less fuel efficient and was designed to

[3] CAISO SLIC Database pMAX values

generate power during “peak” days when electricity demand is high. The gas turbine has black-start capability, that is, it can help the grid recover from major blackouts because it can start up without external power.

Encina recently upgraded the plant to reduce nitrogen oxides (NOx) emissions, which contribute to smog and accelerate global warming. In July 2003, the plant replaced the steam units’ burners with “low-NOx” burners, which operate below the temperature at which NOx forms. The plant also installed a Selective Catalytic Reduction (SCR) system on each of the steam units. These systems inject ammonia into the flue gas and pass the mixture over a catalyst to reduce NOx. With these upgrades, Encina meets current State of California air standards.

In November 2008, the plant changed Unit 4’s control system from analog to digital.[4] The plant did the same on Unit 5 in May 2009. Digital controls allow operators to gather operating data more easily, are easier to operate, and less likely to fail. With access to data, operators can generate trends and statistics and run the unit more efficiently and reliably. The plant has no plans to upgrade controls on Units 1, 2 or 3 because the plant wants to retire these units in the near future.

In September 2007, NRG applied for a license with the California Energy Commission (CEC) to build two new combined-cycle units in the area currently occupied by the plant’s fuel tanks.[5] The new units will add 540-megawatts to the plant’s capacity. The increased capacity will allow the plant to retire Units 1, 2, and 3, but the company plans to operate Units 4 and 5 through at least 2017. The license application is still under CEC review. However, with the State’s new once-through cooling (OTC) regulation, it is uncertain whether NRG will move forward with its plan to construct the new combined-cycle units.

Encina no longer has an RMR[6] contract. The manager of the state’s electric grid, the California Independent System Operator (CAISO), ended the plant’s RMR contract in December 2007. However, because the plant can burn dual fuel and black-start on its own, the CAISO awarded the plant a contract to provide those services. Once a year, the CAISO requires the plant to test and re-certify those capabilities in order to maintain its contract. However as of January 2009, CAISO terminated its dual fuel contract with Encina.

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[4] Analog systems use hydraulic or compressed air controls. Digital systems are electronic.

[5] Docket Number 07-AFC-06 (Application for Certification)

[6] RMR stands for Reliability-Must-Run. Where demand within a local area exceeds the transmission capacity into that area, the CAISO signs RMR contracts with one or more generators in the area to assure that power is available at reasonable prices.

POWER PLANT PERFORMANCE

CPSD used data collected by NERC GADS[7] and analyzed four performance factors to study Encina's operating performance in the last five years:

(1) Net Capacity Factor (NCF),
(2) Equivalent Availability Factor (EAF),
(3) Start Reliability (SR), and
(4) Forced Outage Factor (FOF).

Together, the factors give an insight as to how well the plant has performed in recent years.

NCF measures how close a plant operates to its full capacity. For example, a 50% NCF means a plant generates just half of what it can produce. Table 2 shows Encina's NCF in the last 14 years.

Table 2. Encina's NCF in the last 14 years.

Years	NCF (%)
1995	23
1996	26
1997	28
1998	35
1999	No Data Available
2000	No Data Available
2001	47
2002	No Data Available
2003	No Data Available
2004	37
2005	22
2006	15
2007	8
2008	12

In 2007, Encina generated just 8% of the electricity it can produce. That number is about the same as what other California steam plants had produced in that same year. However, it is dwarfed compared to other North America steam plants, which produced 60% of their total megawatt capacity in 2007. Encina's NCF in 2007 reinforces the fact that California's aging steam plants are becoming less efficient and competitive, and therefore are less likely called upon to run. These steam plants now generally run only during the summer months when demand for electricity is high. During off-peak seasons, these plants idle while hydro and the more efficient combined-cycle plants supply the needed electricity.

[7] NERC is a self-regulatory agency which develops and enforces standards to ensure that the North America power system remains reliable. The agency also maintains the GADS database which it developed in 1982. The GADS database stores operating data that participating power plants submit voluntarily. However, the CPUC's GO 167 makes GADS participation mandatory for California power plants.

Although Encina now runs less, the plant is still able to upkeep with maintenance and operators' skill to keep the plant available. EAF measures a plant's availability to produce power. For example, if a plant breaks down frequently, which makes it unavailable to produce power, then the plant will have a low EAF. Table 3 shows Encina's EAF in the last 14 years.

Table 3. Encina's EAF in the last 14 years.

Years	**EAF (%)**
1995	96
1996	91
1997	93
1998	84
1999	No Data Available
2000	No Data Available
2001	86
2002	No Data Available
2003	No Data Available
2004	87
2005	88
2006	90
2007	89
2008	91

Encina's average EAF remained much about the same before and after deregulation. A high EAF is always desirable, especially for plants that hardly run. In such a case, a high EAF means that even when the plant has been offline for awhile, it can still startup and produce power if it needs to.

Encina's ability to startup reliably also attributes to the plant's high EAFs. SR calculates the ratio of actual starts to attempted starts. It measures how often a plant actually started when it was attempted to start. This index suggests how well a plant is maintained, i.e. a well-maintained plant starts reliably. It also indicates how well operators are trained. Table 4 shows Encina's SR in the last 5 years.

Table 4. Encina's SR in the last 5 years.

Years	**SR (%)**
2004	100
2005	100
2006	100
2007	100
2008	98

Finally, FOF measures how often a plant is in forced outages. Obviously, a low FOF is desirable. Table 5 shows Encina's FOF in the last 5 years.

Table 5. Encina's FOF in the last 5 years.

Years	FOF (%)
2004	2
2005	3
2006	1
2007	2
2008	1

Encina underwent forced outages infrequently; predictably because it had such high EAFs. In 2008, the plant spent just 1% of the time in forced outages; that's only 87.6 hours out of 8,760 hours in a year. That number is slightly better than other California steam plants, which were out 1.5% in 2008, and much better than other North America steam plants, which were out 5% in the same year. This suggests that Encina does well in terms of maintenance to avoid forced outages.

SECTION 1 – SAFETY HAZARDS REQUIRING IMMEDIATE CORRECTION

Staff found no safety hazards that require immediate correction.

SECTION 2 – VIOLATIONS REQUIRING CORRECTION

FINDING 2.1 – THE PLANT FAILED TO REGULARLY INSPECT AND MONITOR FLOW-ASSISTED CORROSION IN HIGH-ENERGY PIPES AND COMPONENTS.

The plant failed to regularly inspect for, monitor, trend, and correct flow-assisted corrosion in high-energy pipes and components, violating operation standards.[8] Flow-assisted corrosion is erosion-corrosion[9] caused by a fast moving fluid at high temperature or by a two phase flow (fluid and steam). Over time, it wears down pipe walls, particularly at elbows, bends and flow restrictions. If the plant fails to monitor and correct the corrosion, pipes can rupture and release high pressure steam, which can damage equipment, and injure or kill workers nearby. Plants must therefore monitor and correct corrosion over time.

The plant has never fully inspected Units 1, 2, and 3 for flow-assisted corrosion, and last inspected Units 4 and 5 in 1997 and 1998 respectively. While those inspections found acceptable remaining wall thicknesses[10], substantial additional corrosion may have occurred because both units have subsequently operated many hours.

Outcome and Follow-up

In response, the plant reiterated that it fully inspected Units 4 and 5 for flow-accelerated corrosion in 1997, and 1998 respectively. CPSD acknowledged the adequacy of those inspections, but those inspections were conducted more than 10 years ago. Substantial corrosion may have occurred because both units have subsequently operated many hours.

The plant stated that since the 1997 and 1998 inspections, it has conducted spot inspections. For example, in December 2001, the plant reexamined the boiler feed pump (BFP) discharge pipe wall, an area where the 1998 inspection revealed possible FAC indications. The 2001 inspection did not detect any wall loss at that location. And then in May 2009, subsequent to the CPUC audit, the plant again reexamined the same location for FAC. Again, the inspection detected no change in wall thickness.

While spot inspections are better than no inspection, CPSD feels that the plant is overdue for a full inspection, particularly on Units 4 and 5, which run more frequently than Units 1, 2, and 3. Flow-assisted corrosion is a complex phenomenon and is affected by multitude of variables. Pipe configuration, design, metallurgy, water chemistry, and operating characteristics are just a few. Consequently, just because the plant reexamined the most prone location and found no corrosion does not mean that there are no corrosion elsewhere in the system. Because of the range of variables involved, one cannot fully address the risks of FAC without a full inspection.

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[8] Operation Standard 27: Flow Assisted Corrosion; Guidelines A, B, C & D

[9] Erosion-corrosion occurs when a metal surface erodes and corrodes at the same time. First, a pipe surface's protective oxide layer (called "magnetite") breaks down. This allows the pipe surface to corrode. As it corrodes, a fast-moving fluid carries away rusts and erodes the pipe. This exposes the pipe surface and allows it to corrode further. And the self-sustaining process continues.

[10] Per ASME Power Piping Code B31.1

Spot inspections do not qualify as full inspections. As such, CPSD expects the plant to do a full inspection as soon as possible and to develop a FAC inspection program going forward.

To the plant's credit, the plant has already taken the initial steps toward creating a FAC inspection program. For example, in November 2008, plant engineers attended an Aptech seminar to learn to develop and implement a FAC monitoring program. The plant will also develop a Piping Assessment Program to comply with a NRG corporate directive. Plant engineers also attended demonstration of advanced FAC inspection equipment, which enable offline inspection without insulation removal. The plant is also evaluating the need to contract outside experts to identify and select pipe locations for FAC inspection. And finally in the interim, the plant plans to do more spot inspections during overhauls in 2010 and 2011 for Units 4 and 5, respectively.

At the meet-and-confer meeting, the plant provided a report of a FAC inspection conducted in April 2010.[11] A company called Q. PRO Technical Services conducted a Pulse Eddy Current (PEC) inspection. PEC is an inspection technology that can inspect insulated carbon steel piping for internal and external corrosion and erosion through the insulation without disturbing the insulation or coating. Q. PRO inspected some piping and pumps for each of the 5 units and presented the data it collected to the plant. However, the report contains no conclusions or recommendations from the inspection. CPSD asks that the plant's engineering staff evaluate the results of the PEC examination and to determine whether corrosion or erosion has occurred which warrant repairs.

CPSD will continue to monitor the plant's progress to meet NRG's corporate directive, which requires the plant to develop a Piping Assessment Program. The program will identify and establish inspection method, location, and frequency. CPSD will inspect Encina and request additional data to determine if the program addresses the risks of high-energy pipe corrosion.

FINDING 2.2 – THE PLANT DELAYED REPAIRS ON UNIT 4'S HIGH PRESSURE STEAM TURBINE.

The plant delayed repairs on Unit 4's high pressure steam turbine, which violates maintenance standards.[12] The steam turbine is a critical piece of equipment. High-pressure and temperature steam flows through the turbine. This causes wear and tear on components along the steam path, particularly on stator vanes and rotating blades. Over time, the metal parts corrode, erode, and undergo metal fatigue and creep. If turbine blades crack and fail, they can fly through the turbine, destroy other blades and puncture the turbine casing. Such incidents can injure or kill workers, and can shut down the plant for many months.

The plant last inspected Unit 4's high pressure steam turbine in 1999.[13] At the time, the 10th stage rotating blades showed initial signs of creep[14]. The contractor who inspected the turbine

[11] PEC Examination for FAC at the NRG Cabrillo Power Plant, Carlsbad, CA dated April 24, 2010
[12] Maintenance Standard 7: Balance of Maintenance Approach; Guidelines A & L
Maintenance Standard 9: Conduct of Maintenance; Guideline H
[13] APTECH report dated June 2008

recommended that the plant replace the blades when the machine reaches 40,000 Equivalent Operating Hours (EOH).[15] At the time of the audit, the machine had already reached 59,000 EOH, but the machine continues to run on its old blades.

Outcome and Follow-up

In response, the plant explained that the contractor's recommendation to replace the 10th stage rotating blades was based on old operating characteristics. The steam turbine now runs mostly at low loads and subject to lower pressure and temperature steam. Furthermore, the unit now runs less. In 1999, the unit operated over 7,300 hours per year with 27 startups. Between 2006 and 2008, the unit operated less than 5,300 hours per year with just 17 startups. The contractor's recommendation to replace the blades at 40,000 EOH did not take into account these new operating characteristics, which resulted in a longer service life. In light of this, the plant extended the replacement interval from 40,000 to 60,000 EOH. Nonetheless in February 2010, the plant overhauled Unit 4's HP steam turbine and replaced all 10th stage rotating blades. No further corrective action is required.

FINDING 2.3 – THE PLANT FAILED TO EVALUATE OR ESTABLISH A SCHEDULE TO COMPLETE SAFETY IMPROVEMENTS TO REDUCE FIRE RISKS.

The plant failed to evaluate or establish a schedule to complete safety improvements to reduce fire risks, violating operation and maintenance standards.[16] The safety improvements reduce the plant's exposure to fires. A fire can injure or kill workers and destroy plant equipment that may shut down the plant for many months. In particular, fires fueled by high-pressure oil sprays can quickly become conflagrations that threaten the entire plant.

In June 2008, Encina's insurer assessed the plant for fire risks. The insurer recommended that the plant:

1) Install fire sprinklers over the turbine bearings. If bearing seals fail, lube oil under high pressure can spray over a wide area. Hot bearing surfaces can ignite the lube oil.
2) Install sprinklers over the lube oil tank. If the tank or its piping ruptures, a large quantity of lube oil can release. If ignited, the lube oil will result in a pool fire. Such a fire can damage the turbine and generator directly above.
3) Develop a procedure to safely shut down the lube oil system when it catches on fire. An oil fire will burn as long as the oil continues to flow. Cutting off the oil too early will damage the turbine, and shutting it off too late will fuel the fire. A safe shutdown procedure will ensure that oil flow will stop as soon as practical.

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[14] Creep occurs when a metal slowly deforms when exposed to prolong periods of stress and heat.
[15] Equivalent operating hours differ from actual operating hours because it takes into account how many start/stop cycle a unit goes through, the amount of time a unit spends over-firing, and other factors which shorten a unit's service life.
[16] Operation & Maintenance Standard 1: Safety; Guideline C3.

4) Install sprinklers over the hydraulic fluid and hydrogen seal oil system. Flange gaskets and fittings may leak and spray a mist of hydraulic and seal oil. Hot surfaces can ignite the oil and result in a spray-fire.
5) Install fire sprinklers over the auxiliary transformers. Transformers use oil to insulate its interior. If the oil loses its insulating property, arcing may occur inside the transformer, sparking an explosion.
6) Install fire sprinklers in the Administration Building. Sprinklers can control a fire before the fire department arrives, greatly reducing total damage.
7) Install a seismic gas shutoff valve for the Storage and Administration Building. The seismic shutoff valve will automatically shut off the gas supply in earthquakes, which are common in Southern California. A strong earthquake can rupture gas lines and release flammable gas that could ignite inside buildings.
8) Perform a periodic leak test of its boiler gas safety shutoff valves.
9) Test the heat sensors and smoke detectors.

At the time of the audit, the plant has not yet evaluated, nor established a schedule to complete these recommendations. While CPSD does not specifically require plants to follow contractor recommendations, it does expect plants to evaluate those recommendations and to provide justifications when the plant declines them.

Outcome and Follow-up

In response, the plant directly complied with the requirements of Items 3, 8, and 9 listed above, and provided explanations and documentation to address the other items in the list. First, in response to Items 3, 8, and 9 above, the plant developed lube-oil shut-off procedures (Item 3), installed a gas seismic shutoff valve[17], and provided documentation showing regular contractor inspections of smoke detectors and gas safety shutoff valves (Items 8 and 9).

Second, in response to the portion of Item 4 relating to electro-hydraulic oil, the plant explained that it uses fire resistant and self extinguishing Fyrquel® Electro-Hydraulic oil[18].

Third, in response to Item 6, lack of automatic sprinklers in the administration building, the plant stated that although its original intention was to install these sprinklers, the administration building is very small, and with multiple exits, making these sprinklers unnecessary. The plant also believes installing water sprinklers in the building could damage critical computer systems, and plans to install an Argonite extinguisher system in the administration building's server rooms later this year. CPSD asks that by April 13, 2011, the plant reports on the installation of this system.

In response to the remaining items, which recommend automatic sprinklers for the turbine bearings (Item 1), lube oil tanks (Item 2), hydrogen seal oil system (Item 4), and auxiliary transformers (Item 5), the plant stated that it relies on portable CO_2 fire extinguishers, staff monitoring for potential fire hazards, and the local fire department, which is only three minutes

[17] Work Order 09-21031, Purchase Requisition MX140118, PO # 66405, and Vendor Invoice #161709.

[18] Fyrquel® Electro-Hydraulic Control Fluids are phosphate ester based fire-resistant fluids formulated with trixylenyl and or butylated phenyl phosphates. The fluids are in the class of "non aqueous hydraulic fluids" sometimes referred to as "synthetic fire resistant fluids".

away. At the meet-and-confer meeting, CPSD verified multiple fire extinguisher systems near the steam turbines (See Photos 2 and 3).


Photo 2. Fire extinguishers are readily available on the turbine deck.

Photo 3. Fire blankets are available near the control room.

Additionally, the plant originally claimed that the use of automatic sprinklers for this equipment was not recommended industry standard, and could cause worse equipment damage. CPSD researched NFPA Codes[19] and FM Global data sheets and found that this claim is not fully supported by current industry practice. In fact, several jurisdictional plants, particularly newer combine-cycle plants, utilize this fire protection technology. CPSD discussed this with the plant

[19] National Fire Protection Association (NFPA) 850. Recommended Practice for Fire Protection for Electric Generating Plants and High Voltage Direct Current Converter Stations.

in a teleconference, and asked the plant to provide further data and justification for its claims, along with a cost-benefit analysis.

The plant provided a cost-benefit analysis, based on EPRI report NP-4144, which indicated only minor financial risk and little cost benefit to a fully engineered automated fire system. The plant found that only 10% of NRG plants nationwide utilize such systems. Additionally, the plant correctly maintains that FM Global, an insurer known for strict standards, still chose to insure the plant.

CPSD notes that Encina completed several other risk mitigation measures that FM Global recommended, which includes:

- Sealing the cable penetrations in Unit 3-4 Control Room,
- Installing locks on sprinkler position control valves,
- Improving the existing sprinkler control valve inspection procedure,
- Developing a Fire Protection System valve list with system designators keyed to the plant fire system site map, and
- Providing exposure protection for control room windows.

FINDING 2.4 – THE PLANT'S EMERGENCY RESPONSE PLAN NEEDS IMPROVEMENT.

The plant's Emergency Response Plan (ERP) violates operation standards[20] because it fails to specify: 1) the steps the plant should take after an emergency, 2) how to respond to earthquakes and wildfires, and 3) who should assume certain emergency duties in case of a fire. Emergencies occur without warning and without proper planning and procedure, the plant cannot effectively respond to emergencies. As a result, emergencies may unnecessarily delay the plant's return-to-service.

First, the ERP lacks response information for earthquake or wildfires, events which have recently occurred in Southern California. The plant's insurer recommends that the plant include specific earthquake response measures in its ERP.

Second, the plant's ERP failed to include information on what steps the plant should take following an emergency, such as which authorities to notify. Although the plant includes some of this information in its Injury and Illness Prevention Plan, the information is lacking in its ERP. Information on how to report safety incidents to the CPUC does not appear in either plan.

Finally, the plant's ERP failed to assign certain emergency duties in the event of a fire. The plant's insurer recommends that the ERP assign someone to monitor fire pumps and sprinkler valves during a fire.

[20] Operation Standard 20: Preparedness for On-Site and Off-Site Emergencies; Guidelines A-E

Outcome and Follow-up
In response, the plant updated its ERP to include: 1) a new procedure for wildfires, 2) instructions for reporting safety incidents to CPSD, and 3) descriptions of staff responsibilities during an emergency. At CPSD's request, the plant also corrected an inaccurate telephone number and added the CPUC safety reporting website information to its ERP.

In addition, the plant updated its Standard Operating Procedures[21] which describe staff duties during an earthquake. These duties include monitoring lagoon level and boiler drafts. The instructions emphasize safety, and require staff to evacuate and congregate in the Emergency Assembly Area until it is safe to return. No further corrective action is required.

FINDING 2.5 – THE PLANT LACKS A PROCEDURE FOR ITS COMPUTERIZED WORK MANAGEMENT DATABASE.

The plant lacks a procedure for processing work orders (WO) entered into Maximo (a software program), violating maintenance standards.[22] A procedure would explain how the plant initiates, tracks, plans, and schedules WOs, which draw a clear line of responsibility for staff. The plant replaced MainSaver with Maximo in May 2008, but did not update the relevant procedure. Without such a procedure, staff may process WOs inconsistently and fail to make timely repairs.

Outcome and Follow-up
In response, the plant explained that it was transitioning from one WO database to another during the audit. At the time, the plant did not have a WO procedure for the new system. Auditors felt that a new procedure should have been in place to avoid workflow confusion. The plant contests that the two systems are very similar and that both systems share a similar process to initiate, plan, schedule, and track WOs. Therefore, the lack of a new procedure would not have caused workflow confusion. Auditors did not investigate in-depth enough to decide whether differences between the two systems may have impeded WO planning. However, since Encina completed the transition and fully trained its staff on the new system, CPSD requires no further corrective action.

FINDING 2.6 – THE PLANT FAILED TO FOLLOW ITS ROOT-CAUSE PROCEDURE WHEN IT INVESTIGATED A NOVEMBER 2006 INCIDENT.

The plant failed to follow its root-cause procedure[23] when it investigated a November 2006 outage when an expansion joint failed, violating operation standards.[24] A root-cause investigation is a systematic way to identify the ultimate causes of failures to prevent recurrence. Failing to follow the procedure to investigate systematically may lead to misdiagnosis and improper correction.

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[21] Operator Instruction Manual, Instruction 820.10.1.5, dated September 29, 2009.
[22] Maintenance Standard 8: Maintenance Procedures and Documentation; Guideline H
[23] Directive No. – OPO – 207 dated July 7, 2008
[24] Operation Standard 4: Problem Resolution and Continuing Improvement; Guideline B

An auditor reviewed three root-cause analyses that the plant conducted in recent years. The auditor also reviewed the plant's procedure for root-cause investigations. The auditor noticed that at least one analysis did not conform to the procedure. In November 2006, a failed expansion joint took Unit 4 out-of-service. The plant investigated and attributed the failure to improper operating procedures. While the plant has identified the root cause and has since revised that procedure to prevent recurrence, the plant failed to follow its root-cause procedure when it conducted the analysis. According to the root-cause procedure, each person who is involved in an incident must fill out an interview form. The plant uses the form to collect factual information so that the plant can investigate a failure thoroughly. The analysis for the expansion joint incident lacks those interview forms.

Outcome and Follow-up

In response, the plant explained that the root-cause analysis for the November 2006 incident was conducted per the old procedure. Since July 7, 2008, the plant has adopted a newer and more detailed procedure that governs how staff conducts RCA. The old procedure was more general and did not prescribe the forms that were required under the new procedure.

In December 2008, since the plant adopted the new procedure, twenty plant staff attended a problem-solving class to learn how to properly investigate and conduct RCA. The plant also designated its Technical Service Group to oversee all root-cause investigations. In January 2009, the plant fully implemented the newly RCA process. NRG is also currently developing a company-wide RCA database to keep record of RCA investigations which would enable staff to offload lessons learned from incidents across NRG's fleet of power plants.

CPSD asked that the plant provide a copy of RCA done per the new procedure, if any. In April 2010, the plant submitted a RCA investigation conducted under the new procedure. The investigation used the Kepner-Tregoe RCA technique to investigate a discharge pipe failure on Unit 5's electro-hydraulic pump. The failure, which took place in January 2009, was the second failure in recent history. The RCA identified the root cause to be improper weld preparation during the initial repair. The RCA conformed to the plant's new procedure. No further corrective action is required.

FINDING 2.7 – THE LEAD OPERATOR COULD NOT EXPLAIN A DIGITAL DISPLAY'S FUNCTION AND COULD NOT EXPLAIN WHY THE DISPLAY WAS TAGGED OUT.

The lead operator could not explain the function of a digital display, or why the display was tagged out, which violates operation standards.[25] The lead operator takes charge in the control room and therefore should know the function and status of controls at all times. This lack of awareness compromises operational reliability and workers' safety.

An auditor toured the control room and saw a deficiency tag on a digital display. He then asked the lead operator at the time to explain the display's function and the reason for the tag. The lead operator was unable to explain the display's function or why it was tagged.

[25] Operation Standard 8: Plant Status and Configuration; Guideline A1

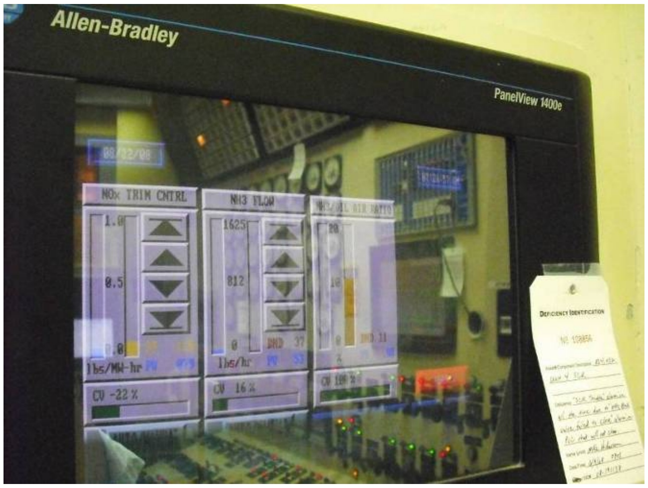

Photo 4. Deficiency tag on a digital display in the control room.

Outcome and Follow-up

In response, the plant explained that the digital display is used to control Unit 4's SCR system.[26] The plant tagged the display because the display annunciated a false alarm. The plant explained that the lead operator at the time did not understand the auditor's question or the implication of the auditor's question. However, the auditor's question was simple and direct, and the implication is to test how well a lead operator knows his or her controls.

In light of this finding, the plant has traced the deficiency to a faulty solenoid valve. The plant has since replaced the valve, cleared all alarms, and restored the system to service. In October 2009, the plant had also retrained its operators on this system. No further corrective action is required.

FINDING 2.8 – THE PLANT HAS TWO BLACK-START TEST PROCEDURES THAT CONFLICT WITH EACH OTHER.

The plant has two black-start test procedures that conflict with each other, violating operation standards.[27] The plant has a two-page, informal, procedure and as well as a more detailed and formalized procedure that was a part of the plant's operator manual.[28] The plant uses the procedure to test whether the gas turbine can black-start the steam units. The conflict may confuse staff and cause test errors or inconsistent test results.

Outcome and Follow-up

In response, the plant explained that the two black-start procedures work in conjunction with each other. The two-page informal procedure is a corporate-wide black-start procedure for all NRG facilities. The detailed procedure is a plant-specific standard operating procedure. The

[26] The SCR system injects ammonia into the flue gas stream. The mixture passes through and reacts with catalysts to reduce Nitrogen Oxide. The plant relies on this system to comply with air emission limits.
[27] Operation Standard 12: Operations Conduct; Guidelines A-E
[28] NRG Cabrillo Power Operations Inc, Operator Instruction Manual, Gas Turbine – Test of Black Start Capabilities

plant reviewed the two procedures and confirmed that following each procedure correctly will not yield test errors or inconsistent test results. However, the fact that two procedures exist for the same thing may confuse staff. CPSD asked and the plant added a note on its standard operating procedure to refer to the corporate-wide procedure. No further corrective action is required.

FINDING 2.9 – THE PLANT DELAYED REPAIRS ON ITS CIRCULATING WATER TUNNEL.

The plant delayed repairs on its circulating water tunnel, violating maintenance standards.[29] The circulating water tunnel channels seawater from the lagoon to each unit's condenser for cooling. The deteriorating tunnel poses safety risks for workers and threatens the plant's reliability.

The deteriorating tunnel poses safety risks for workers. On several occasions, concrete actually fell from the tunnel's ceiling. Falling concrete can injure or kill workers who go inside to clean and inspect the tunnel. Operators who walk atop the tunnel to routinely inspect the units can trip and fall over deteriorating concrete and uneven walk surfaces.

In addition, because the deteriorating tunnel might collapse, the repair delays threaten the plant's reliability. Even a partial collapse would restrict water flow to the condensers. This would reduce a condenser's cooling capacity and limit a unit's power output.

As a precaution, the plant erected a warning sign at the tunnel's entry. The plant also said it will hire a contractor to use a special epoxy to repair the tunnel. At the time of the audit, the plant has not yet repaired the deteriorating tunnel.

Photo 5. Sinking concrete atop the circulating water tunnel.

Outcome and Follow-up

In response, the plant acknowledged that the circulating water (CW) tunnel is a critical plant asset, of which if not properly maintained, may threaten the plant's reliability. In 2006, the plant evaluated bio-fouling coatings on the tunnel. At the time, the plant pull tested random areas of

[29] Maintenance Standard 7: Balance of Maintenance Approach; Guidelines A & L
Maintenance Standard 9: Conduct of Maintenance; Guideline H

Unit 4's tunnel per ASTM D4541 standards[30]. The test results indicated that the tunnel is structurally sound and in good condition. The plant also stated that it regularly cleans and maintains its tunnel. The plant provided documents that showed it cleaned all four tunnels in 2009.[31]

However, the plant did not provide "pull-test" records for other tunnels. The plant must maintain the integrity of its circulating water tunnels. If it chooses not to conduct more extensive testing, at a minimum it must conduct regular and frequent visual inspections, and insure that the tunnels experience no instances of falling concrete or debris. The plant also admits that the CW deck does have areas of de-lamination, which the plant had repaired before, but which delaminated again. The plant further states that:

> "The concrete in the picture is not in danger of breaking or falling into the circulating water tunnel, but it can present a tripping hazard to employees; the bright orange cones and barrier tape are mitigating actions. Any areas on the CW deck providing critical access have been promptly repaired; areas that are not providing critical access are isolated and marked, and will be repaired in normal course."

The plant made multiple repairs (See Photo 6), and allocated funds in the budget for future repairs. The plant also agreed to add inspection requirements to its tunnel cleaning procedures and checklists. No further corrective action is required.

Photo 6. The plant repaired areas of surface delamination.

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[30] ASTM (American Society for Testing and Materials) D4541 - 09 Standard Test Method for Pull-Off Strength of Coatings Using Portable Adhesion Testers. According to their website, "ASTM International is one of the largest voluntary standards development organizations in the world-a trusted source for technical standards for materials, products, systems, and services."

[31] The work order (WO) numbers for the tunnel cleanings are as follows: Units 1-3 WO#09-5790, Unit 4 WO#09-38067 and Unit 5 WO#09-71843

FINDING 2.10 – THE PLANT DELAYED REPAIRS ON A RECIRCULATION FAN BEARING.

The plant delayed repairs on a recirculation fan bearing, violating maintenance standards.[32] The recirculation fan recycles flue gas into the furnace for re-burn. The defective bearing has registered higher than normal operating temperature. At the time of the audit, the plant used an air blower to blow ambient air to the bearing to keep it from overheating. The bearing can fail if operators continue to operate it above its normal temperature. If the bearing fails, it will take the recirculation fan out-of-service and limit the unit's power output.

Photo 7. The plant blows air to the bearing to keep it from overheating.

Outcome and Follow-up
In response, the plant clarified that the outboard seal on the re-circ fan failed and not the bearing. The defective seal allowed hot flue gas to leak out. The plant, therefore, placed an air blower to disperse the heat to mitigate burn risks hazards. Subsequently on October 29, 2008, the plant repaired the outboard fan seal via Work Order #08-282124. No further corrective action is required.

FINDING 2.11 – THE PLANT DELAYED REPAIRS ON ASBESTOS-LADEN INSULATION.

The plant delayed repairs on asbestos-laden insulation, which violates operation and maintenance standards.[33] Asbestos is resistant to heat and is often used in pipe insulation. Asbestos insulation was exposed at a valve on Unit 4. Workers who inhale asbestos face an increased risk of cancer. Also, broken insulation poses burn-risk hazards to operators who walk the area routinely to inspect the unit.

[32] Maintenance Standard 7: Balance of Maintenance Approach; Guidelines A & L
Maintenance Standard 9: Conduct of Maintenance; Guideline H
[33] Operation & Maintenance Standard 1: Safety; Guidelines A2 & C3

Photo 8. Asbestos insulation exposed at a valve on Unit 4.

Outcome and Follow-up

In response, the plant hired an insulation contractor to analyze the insulation for asbestos. The result was negative and the plant provided a copy of the analysis. To mitigate burn risk hazards, the plant repaired the broken insulation. No further corrective action is required.

(Before)

(After)

FINDING 2.12 – THE PLANT DELAYED HIGH-PRIORITY CORRECTIVE REPAIRS.

The plant delayed high-priority corrective repairs, violating operation and maintenance standards.[34] Corrective repairs are repairs ordered after something has already failed. Delaying corrective repairs, especially those of high-priority, can inflict more damage and result in longer

[34] Operation & Maintenance Standard 1: Safety; Guidelines A1 & C3
Maintenance Standard 7: Balance of Maintenance Approach; Guidelines A & L

outages. At the time of the audit, the plant had 266 pending corrective repairs.[35] Three of them were of highest priority and were three months overdue at the time:

(1) Work Order # CB1C119045 reported an oil leak from a boiler-feed-pump throttle valve. Although the work order stated that "*oil was dripping onto hot piping causing an extremely high risk of fire*", the leakage posed no immediate fire hazard because the oil leak is slow (about one drop per second) and that the plant has temporarily installed metal sheeting which redirects the oil away from hot surfaces. Nevertheless, the plant has delayed this repair and the plant must repair the leak before it gets worse.

Photo 9. The plant temporarily installed metal sheeting which redirects oil drips away from hot surfaces.

(2) Work Order # CB1C119011 reported a broken Hankison RefrigiFilter. This equipment removes moisture from the air that the plant uses to control pneumatic instruments. Moist air can cause instruments to malfunction and affect the plant's operation.
(3) Work Order # CB1C117554 reported a defective flood-chamber valve. The defective valve has caused large water puddle to form on the ground near Site Column 20A. Water puddle is a breeding ground for algae and poses slip-and-fall hazards for workers who walk the area to routinely inspect equipment.

[35] Corrective Maintenance (CM) Work Order Backlog Report dated 8/15/08

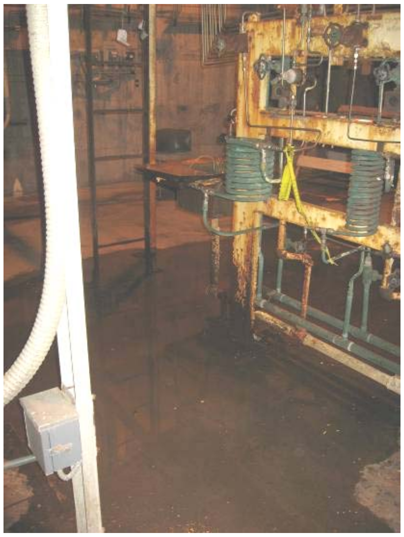

Photo 10 and 11. A defective chamber valve causes large water puddle to form on the ground near Site Column 20A.

Outcome and Follow-up

In response, the plant explained that the three work orders cited were not fix-it-now (FIN) repairs because the deficiencies posed no imminent safety hazards. To the contrary, operators entered the work orders and designated them a priority five, the highest priority in the work order system. If the repairs were not urgent, as the plant explained, then the plant needs to retrain its operators to distinguish FIN repairs from non-urgent repairs so that they will correctly prioritize work orders in the system. Proper work order priorities enable the plant to allocate resources in the most effective manner.

At CPSD's request, the plant retrained its staff on work order priority. The plant conducted training in June 2010. All personnel who enters, prioritizes, and approves work orders attended the training. The plant provided a presentation and an attendance report for the training. CPSD requires no further corrective action.

FINDING 2.13 – THE PLANT LACKS A KNOWLEDGE RETENTION PROGRAM.

The plant lacks a knowledge retention program, which violates operation and maintenance standards.[36] Such a program would collect what is sometimes called “Tribal knowledge”, undocumented processes, procedures, and expertise that an organization develops over time. Many of Encina’s senior staff worked for SDG&E and will retire in the near future. Unless Encina develops a program to retain and transfer tribal knowledge to other staff, upcoming retirements may affect the plant’s operation.

[36] Operation Standard 3: Operations Management and Leadership; Guideline C1
Operation Standard 4: Problem Resolution and Continuing Improvement; Guideline C
Maintenance Standard 3: Maintenance Management and Leadership; Guideline C1

Outcome and Follow-up

In response, the plant submitted a spreadsheet that projects Encina's staffing needs through 2011. The spreadsheet shows that in 2007 the plant filled six "transition positions".[37] Transition positions are positions filled early on so new employees can transition into their new roles as they replace outgoing employees. While the plant anticipates retirements and actively fills transition positions, auditors found no evidence that the plant has a knowledge retention program or strategy, such as mentorship, knowledge transfer training, or exit interviews. CPSD believes the plant benefits if it develops a program to retain critical and undocumented knowledge before an exodus of veteran employees.

At the meet-and-confer meeting, the plant explained that knowledge retention is only critical for positions in operations and instrumentation and control. In that regards, the plant has an extensive training and certification program for those positions. Operators are classified into one of four different skill levels (OMT-1 to OMT-4). At each level, an operator attends training classes, mentors with an experienced operator, takes written and hands-on performance tests. Upon successful completion, the O&M Manager has to approve before an operator progresses to the next skill level. At the top level, OMT-4 operators are often involved in many levels of work processes, such as creating checklists and work procedures to capture institutional knowledge. The plant briefed auditors on its operator training and certification process and provided a current training status of its operators. CPSD requires no further corrective action.

FINDING 2.14 – THE PLANT FAILED TO POST EVACUATION MAPS AND SIGNS THROUGHOUT THE FACILITY.

The plant failed to post adequate maps and signs, a violation of operation standards.[38] Although the plant maintains a thorough evacuation procedure and identifies its assembly areas clearly, the plant failed to post maps of evacuation routes and assembly areas. Contractors or new employees who are unfamiliar with the plant's layout may become disoriented in emergencies and face unnecessary safety risks. Assembling such workers may slow the plant's response to the emergency.

Outcome and Follow-up

In response, the plant posted evacuation maps and added additional exit signage. Additionally, the plant marked exit pathways with luminescent tape (See Photo 12). The plant also placed warning signs at doors and stairways that are ***not*** exit paths. The plant notes that it already discusses emergency exit procedures with contractors during its pre-outage safety orientation. No further corrective action is required.

[37] Four auxiliary operators and two shift supervisors
[38] Operation Standard 20: Preparedness for On-Site and Off-Site Emergencies

Photo 12. The plant marked this exit stairwell with luminescent tape.

FINDING 2.15 – THE PLANT FAILED TO MAINTAIN AN ATTENDANCE LIST AT ONE OF THE ASSEMBLY AREAS.

The plant failed to maintain an attendance list at one of the assembly areas, a violation of operation standards.[39] In an evacuation, plant staff gathers at one of three assembly areas. The safety manager uses the attendance list at the assembly area to take roll call. Without an attendance list, the safety manager cannot accurately account for onsite staff. This slows the plant's response to the emergency.

Outcome and Follow-up

In response, the plant stated that on September 25, 2008 it held an evacuation drill, at which time it verified that each assembly areas had attendance sheets in place. In addition, the plant grouped these attendance sheets based on job classification in order to facilitate checking attendance during an evacuation. The plant explained that the security guard keeps a real-time list of all staff and visitors on site. During an evacuation, the safety manager at each assembly areas takes roll call on an attendance sheet, and then brings these sheets to the guard's station to reconcile with the real-time list. In July 2009, the plant updated all attendance lists at each of the assembly areas. CPSD asked and the plant created a recurring work order to update the attendance list on a regular basis. No further corrective action is required.

[39] Operation Standard 20: Preparedness for On-Site and Off-Site Emergencies

FINDING 2.16 – THE PLANT FAILED TO LABEL CRITICAL SYSTEM COMPONENTS.

The plant failed to label critical system components, a violation of operation standards.[40] In particular, the plant did not label feed-water heaters for Units 1 and 2 that are near each other. Without clear signage, operators can mistake one unit's heater for another's, leading to maintenance or operational errors, reducing the plant's reliability and safety.

Outcome and Follow-up

In response, the plant stated that it has started labeling critical system components. The plant has already labeled about 72% of all valves in all units. The plant's goal is label all critical control, isolation, and pressure relief valves. The plant has also labeled about 50% of its feedwater system components, which include feedwater heaters.

At the meet-and-confer meeting, the plant stated that it has labeled about 84% of all valves in all units. For its feedwater system, labeling is about 80% complete. The plant has committed to complete all labeling by December 2010. CPSD asks that by April 13, 2011, the plant reports on the progress of its labeling effort.

Photo 13. A metal valve tag on an attemperator.

[40] Operation Standard 5: Operations Personnel Knowledge and Skills; Guideline D

Photo 14. The plant labeled Unit 1's feedwater heater.

Photo 15. The plant labeled Unit 2's induced draft fan motor.


Photo 16. Unit 1's condensate storage tank to be labeled.

SECTION 3 – OBSERVATIONS

OBSERVATION 3.1 – THE PLANT FOLLOWS A STRICT PROCESS TO SELECT AND QUALIFY CONTRACTORS.

The plant maintains a list of qualified suppliers and contractors. The plant contracts only with firms on this list. The plant adds new suppliers to the list only after a strict qualification process.

The plant uses a web-based program called "Ariba" to pre-qualify suppliers. Potential suppliers answer an extensive list of questions, concerning the company's experience, qualification and employees' certification. The plant also looks at the company's Experience Modification Rating (EMR) to determine the company's safety history. EMR measures how many claims a company has filed for workers' compensation, and compares that number to those of similar companies. A lower EMR means a company has had fewer accidents.

Once a potential supplier completes the questionnaire, the plant's safety manager must review and approve it before the plant can award the supplier a contract. An auditor reviewed the completed questionnaire of Total Western, a company contracted to provide repair service to Encina. The questionnaire conformed to the plant's qualification process.

OBSERVATION 3.2 – THE PLANT REQUIRES CONTRACTORS TO COMPLETE A CONTRACTOR SAFETY NOTICE BEFORE THEY CAN START WORK.

Before contractors can start work, the plant requires them to fill out a 31-page contractor safety notice. The plant issues contractors this notice at the pre-job briefing, held before the contractor commences work on the first day. The contractor must read the notice and initial each section to acknowledge that he or she understands it. At this time, the plant also discusses with the contractor any specific safety issues that relates to the job at hand. The contractor receives a copy of the notice while the plant keeps the original on-file. An auditor reviewed the contractor safety notices of three companies and found them consistent with the process.[41]

OBSERVATION 3.3 – THE PLANT USES CHECKLISTS FOR ROUTINE INSPECTION.

The plant uses checklists for routine inspection. An auditor walked-down Unit 4 alongside an operator. While the operator did not carry a checklist with him, he did have a note pad to write down any deficiencies he observed. After the walk-down, the operator returned to the control room where he filled out a checklist and filed it away in the shift supervisor's office. The auditor reviewed several completed checklists, which conformed to the routine inspection.[42] However

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[41] Contractor safety notice for Preferred Piping, dated 12/19/07, to repair #3 basement air compressor
Contractor safety notice for Laser Electric, dated 12/18/07, to maintain office's air conditioning unit
Contractor safety notice for Vortex, dated 12/17/07, to inspect crane at circulating water deck

[42] NRG Cabrillo Basement Log Sheet Units 1, 2, and 3

during the walk-down, the auditor saw several equipment defects. See Findings 2.9, 2.10, and 2.11.

OBSERVATION 3.4 – THE PLANT MAINTAINS A LOGBOOK COMPLIANCE DOCUMENT ONSITE.

General Order 167 Section 5.6 requires plants to maintain onsite a logbook compliance document. This document explains how and where plants record their logbook data. An auditor reviewed Encina's operators' log manual, which met the requirement of GO 167. The auditor also reviewed a copy of an actual log which conformed to the plant's log manual.[43]

OBSERVATION 3.5 – THE PLANT IMPLEMENTS A LOCK-OUT TAG-OUT PROGRAM.

The plant uses a lock-out tag-out program and follows a strict clearance procedure. If a piece of equipment needs repair, the plant not only tags and de-energizes it, but it also locks it such that the equipment stays electrically isolated. This prevents someone from accidentally turning the equipment on while a worker repairs it. Under this program, only the technician in charge of the repair can take the equipment out-of-service, and only the person who placed the lock can remove it. If the person who placed the lock is absent, only the shift supervisor can override his or her authority and remove the lock. The plant has a shack where it keeps all the locks and binders that track all active clearances. The plant also trains its staff on the clearance procedure regularly.

NRG Cabrillo Sub-basement Log Sheet Units 4 and 5
NRG Cabrillo Unit 1, 2, and 3 Boiler Casing Leak Inspection Log
NRG Cabrillo Unit 4 and 5 Boiler Casing Leak Inspection Log

[43] Unit 5's control operator's log dated 8/4/08

Photo 17 and 18. On the turbine deck, the plant has a shack where it keeps its locks and binders that track all active clearances.

OBSERVATION 3.6 – THE PLANT CONDUCTS EVACUATION DRILLS REGULARLY.

The plant conducts evacuation drills regularly. The plant conducts two evacuation drills annually. The plant seeks continuous improvements by evaluating every drill. An auditor reviewed drill evaluations and verified that the plant conducted at least two drills in each of the last two years. The evaluations stated that all staff was accounted for in each of the drills and did not note any deficiencies.

OBSERVATION 3.7 – THE PLANT KEEPS ITS FACILITY ORDERLY AND CLEAN.

The plant keeps its facility orderly and clean. The plant is clean, particularly inside the power plant building. The plant stores unused equipment properly; secured and away from walk-aisles. During the plant tour, an auditor saw the shift supervisor repeatedly picking up and properly disposing trash and debris.

Photo 19. The plant keeps the turbine deck clean and orderly.

OBSERVATION 3.8 – THE PLANT MAINTAINS ITS CATHODIC PROTECTION SYSTEM.

The plant inspects and maintains its cathodic protection system regularly. A cathodic protection system prevents underground pipes from corrosion, particularly cooling water pipes. It works by applying an electric current to an anode on the pipe. This forces the anode to corrode rather than the pipe. As such, the anode is called a “sacrificial” anode. Once the anode corrodes completely, the plant must replace it with a new anode in order to continue to protect the pipe. If the plant does not upkeep its cathodic protection equipment, underground pipes will corrode rapidly and will eventually fail.

An auditor reviewed the cathodic protection report for 2003, and for 2005 through 2008.[44] In each of these years, the plant hired a specialist (Norton Corrosion) to inspect its cathodic protection systems on all five units. The specialist inspected the rectifiers, anodes and reference cells[45] on the traveling screens, condenser waterboxes, and cooling water pipes.[46]

The plant repaired all defects found by the inspections. For example, the 2003 inspection report lists several defective anodes and reference cells.[47] The 2005 report indicates that the plant had replaced these items. The most recent report, completed in June 2008, lists several defective parts. The plant has created work orders to repair them.[48]

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[44] Norton Corrosion Limited – Cathodic Protection Annual Survey for 2003, 2005, 2006, 2007, and 2008

[45] A rectifier converts AC voltage to DC voltage for the impressed current. Reference cells provide a known voltage level and are used in testing.

[46] Traveling screens filter the intake cooling water for the condensers. The condenser waterbox is where the cooling water enters the condenser to cool the steam from the turbine.

[47] U5 – East Reference Cell #2 South pipe, Reference Cell #4 North pipe, U5 – West Anodes 21, 22, 23 & 24 North pipe

[48] WO# 08-335468, #08-335462, and #08-335472

OBSERVATION 3.9 – THE PLANT IS WELL-STAFFED IN A NUMBER OF AREAS.

The plant has staff in the operational, maintenance, and technical area. The plant employs six engineers, five planners, and has dedicated trainers, environmental and safety specialists. Twenty-five Total Western maintenance staff, including a foreman, work full-time at the plant. The plant employs a full-time chemist and a document-control clerk. During each shift, a supervisor directs the work of a staff of three for each pair of units: a control operator, assistant control operator, and an auxiliary operator.

OBSERVATION 3.10 – THE PLANT VERIFIES CONTRACT EMPLOYEES' QUALIFICATIONS.

The plant verifies contract employees' qualifications. The plant employs 25 contract employees who work for Total Western. These employees work full time onsite. The plant relies on them for many of its maintenance and repairs. While contract employees get their training from Total Western, the plant does due-diligence to verify whether the training actually took place. For example, contract employees clean the traveling screens regularly. The plant keeps a record that shows who received the proper training and, therefore, can do the job. Additionally, the plant checks to ensure contract employees are competent to do their jobs. For example, Total Western has welders whose welding skills meet American Society of Mechanical Engineers (ASME) specifications. The plant verifies the welders' certification before it allows the welders to weld.

OBSERVATION 3.11 – THE PLANT INSPECTS ITS CRANES AND FORKLIFTS REGULARLY.

The plant inspects its cranes and forklifts and maintains records of those inspections. An auditor selected two records at random and verified that the plant has inspected its cranes and forklifts within the last year.

OBSERVATION 3.12 – THE PLANT CONTROLS AND UPDATES ITS EQUIPMENT DIAGRAMS.

The plant manages its equipment diagrams and has a well-defined process to update them. The plant stores its drawings and schematics at one central location and assigns a clerk to manage them. The room has copiers and plotters so staff can make copies of drawings and not take the originals away. The plant keeps those drawings electronically, but also maintains a set of hardcopies. The plant keeps its drawings organized and maintains a catalog of those drawings.

The plant has a well-defined process to update its drawings. If the plant upgrades or replaces a piece of equipment, it also updates its drawing to reflect the changes. The plant maintains two sets of drawings. It keeps a set of "as-built" master drawings and a set of "working" drawings. If new equipment or an upgrade changes the plant's configuration, technicians make the necessary changes on the "working" drawings. Engineers must review and approve the changes before the technician can replace the "as-built" masters with the new drawings.

The plant keeps its drawings organized and maintains a catalog of those drawings. The plant catalogs its "as-built" drawings both electronically and on paper. The drawings themselves are also available electronically and on paper. An auditor asked to see the drawing of Unit 4's cathodic protection system.[49] The clerk and the engineer searched the two cataloging systems at the same time, and within seconds they both located the electronic and hard-copy drawing.

[49] Project # 13-7972, Drawing E-101, Revision C. "Condenser Cathodic Protection Conduit Run and Wiring Diagram"

EXHIBIT B

Docket No. 07-AFC-6

CENTER FOR BIOLOGICAL DIVERSITY'S RESPONSE IN SUPPORT OF CITY OF CARLSBAD'S MOTION TO TAKE OFFICIAL NOTICE AND THE CENTER'S MOTION TO TAKE OFFICIAL NOTICE AND RE-OPEN THE EVIDENTIARY RECORD

California ISO
Your Link to Power

2009 RMR / Black Start / Dual Fuel Contract Status
(Based on CAISO Actions and FERC Filings by Unit Owners)

RMR Unit Extension Status (Modified December 1, 2008) *Extended RMR Contracts are effective January 1, 2009 thru December 31, 2009* *Released RMR Contracts terminate effective Midnight on December 31, 2008*				
Owner	***RMR Contract***	***Unit***	***MW[1]***	***Status***
CalPeak Power – Border, LLC	Border	Border Unit	43.8	Extended
CalPeak Power – El Cajon, LLC	El Cajon	El Cajon Unit	42.2	Extended
CalPeak Power – Enterprise, LLC	Enterprise	Escondido Unit	45.5	Extended
Geysers Power Company, LLC (Calpine)	Geysers Main	Geysers Main, Units 6	40	Released
Gilroy Energy Center, LLC (Calpine)	Gilroy EC	Feather River EC Unit	45	Extended
		Gilroy EC, Unit 1	45	
		Gilroy EC, Unit 2	45	
		Yuba City EC Unit	45	
Los Medanos Energy Center, LLC (Calpine)	LMEC	Los Medanos Energy Center	556	Extended
Mirant Potrero, LLC	Potrero	Potrero, Unit 3	206	Extended
		Potrero, Unit 4	52	
		Potrero, Unit 5	52	
		Potrero, Unit 6	52	
Dynegy Oakland, LLC	Oakland	Oakland, Unit 1	55	Extended
		Oakland, Unit 2	55	
		Oakland, Unit 3	55	
Dynegy South Bay, LLC	South Bay	South Bay, Unit 1	145	Extended
		South Bay, Unit 2	149	
		South Bay, Unit 3	174	
		South Bay, Unit 4	221	
		South Bay, CT	13	
Cabrillo Power II LLC (NRG)	Cabrillo II	Kearny 2A CT	14	Released
		Kearny 2B CT	14	
		Kearny 2C CT	14	
		Kearny 2D CT	13	
		Kearny 3A CT	15	
		Kearny 3B CT	14	
		Kearny 3C CT	14	
		Kearny 3D CT	14	
		Miramar 1A CT	17	
		Miramar 1B CT	16	

[1] Capacity values shown indicate the summer maximum net dependable capacity (MNDC) values for the combustion turbines with both summer and winter MNDC values specified in the Cabrillo I, Cabrillo II, and South Bay RMR contracts.

California ISO
Your Link to Power

2009 RMR / Black Start / Dual Fuel Contract Status
(Based on CAISO Actions and FERC Filings by Unit Owners)

Black Start Units Extension Status (Modified December 1, 2008) *Extended Black Start Contracts are to be effective January 1, 2009 thru December 31, 2009*				
Pacific Gas and Electric Company	Humboldt Bay	Humboldt Bay, MEPP 2	15	Extended
		Humboldt Bay, MEPP 3	15	
	Kings River WS	Kings River Watershed II Units	335.8	Extended
	San Joaquin WS	San Joaquin Watershed Units	214.7	Extended
Southern California Edison		Hoover	525	Extended
		Big Creek Physical Scheduling Plant	368.9	
		Barre Peaker	47	
		Center Peaker	47	
		Grapeland Peaker	46	
		Mira Loma Peaker	46	
Cabrillo Power I, LLC	Cabrillo I	Encina CT	14	Extended
Cabrillo Power II LLC (NRG)		Kearny 2A CT	14	New
		Kearny 2C CT	14	
		Kearny 3A CT	15	
		Kearny 3C CT	14	
		Miramar 1A CT	17	
Dual Fuel Agreement Unit Extension Status (Modified December 1, 2008) *Extended Dual Fuel Contracts are to be effective January 1, 2009 thru December 31, 2009*				
Pacific Gas and Electric Company	Humboldt Bay	Humboldt Bay, Unit 1	52	Extended
		Humboldt Bay, Unit 2	53	
Cabrillo Power I LLC	Cabrillo I	Encina Unit 1	106	Terminated
		Encina Unit 2	103	
		Encina Unit 3	109	
		Encina Unit 4	299	
		Encina Unit 5	329	

EXHIBIT C

2008 RMR / Black Start / Dual Fuel Contract Status

(Based on CAISO Actions and FERC Filings by Unit Owners)

RMR Unit Extension Status
Extended RMR Contracts are effective January 1, 2008 thru December 31, 2008
Released RMR Contracts terminated effective Midnight on December 31, 2007

Owner	***RMR Contract***	***Unit***	***MW[1]***	***Status***
CalPeak Power – Border, LLC	Border	Border Unit	43.8	Extended
CalPeak Power – El Cajon, LLC	El Cajon	El Cajon Unit	42.2	Extended
CalPeak Power – Enterprise, LLC	Enterprise	Escondido Unit	45.5	Extended
Geysers Power Company, LLC (Calpine)	Geysers Main	Geysers Main, Units 6	40	Extended
Gilroy Energy Center, LLC (Calpine)	Gilroy EC	Feather River EC Unit	45	Extended
		Gilroy EC, Unit 1	45	
		Gilroy EC, Unit 2	45	
		Yuba City EC Unit	45	
Los Medanos Energy Center, LLC (Calpine)	LMEC	Los Medanos Energy Center	556	Extended
Dynegy Oakland, LLC	Oakland	Oakland, Unit 1	55	Extended
		Oakland, Unit 2	55	
		Oakland, Unit 3	55	
Dynegy South Bay, LLC	South Bay	South Bay, Unit 1	145	Extended
		South Bay, Unit 2	149	
		South Bay, Unit 3	174	
		South Bay, Unit 4	221	
		South Bay, CT	13	
Cabrillo Power I LLC (NRG)	Cabrillo I	Encina Unit 1	106	Released, Dual Fuel Agreement executed in lieu of RMR
		Encina Unit 2	103	
		Encina Unit 3	109	
		Encina Unit 4	299	
		Encina Unit 5	329	
		Encina CT	14	Released, Black Start Agreement executed in lieu of RMR
Cabrillo Power II LLC (NRG)	Cabrillo II	El Cajon CT	13	Released
		Kearny 1 CT	15	
		Kearny 2A CT	14	Extended
		Kearny 2B CT	14	
		Kearny 2C CT	14	
		Kearny 2D CT	13	
		Kearny 3A CT	15	
		Kearny 3B CT	14	
		Kearny 3C CT	14	
		Kearny 3D CT	14	
		Miramar 1A CT	17	
		Miramar 1B CT	16	
Mirant Delta, LLC	Contra Costa	Contra Costa, Unit 4	0[2]	Released
		Contra Costa, Unit 5	0[2]	

[1] Capacity values shown indicate the summer Maximum Net Dependable Capacity (MNDC) values for the CTs with both summer and winter MNDC values specified in the Cabrillo I, Cabrillo II, and South Bay RMR Contracts.
[2] Unit is a synchronous condenser.

CAISO PUBLIC

2008 RMR / Black Start / Dual Fuel Contract Status

(Based on CAISO Actions and FERC Filings by Unit Owners)

Mirant Potrero, LLC	Potrero	Potrero, Unit 3	206	Extended
		Potrero, Unit 4	52	
		Potrero, Unit 5	52	
		Potrero, Unit 6	52	
Northern California Power Agency	NCPA CTs	Alameda, Unit 1	22.5	Released
		Alameda, Unit 2	22.5	
Black Start Units Extension Status *Extended Black Start Contracts are to be effective January 1, 2008 thru December 31, 2008*				
Pacific Gas and Electric Company	Humboldt Bay	Humboldt Bay, MEPP 2	15	Extended
		Humboldt Bay, MEPP 3	15	
	Kings River WS	Kings River Watershed II Units	335.8	Extended
	San Joaquin WS	San Joaquin Watershed Units	214.7	Extended
New Interim Black Start Agreement Units *New Black Start Contracts are to be effective January 1, 2008 thru December 31, 2008*				
Southern California Edison		Hoover	525	New
		Big Creek Physical Scheduling Plant	368.9	
		Barre Peaker	47	
		Center Peaker	47	
		Grapeland Peaker	46	
		Mira Loma Peaker	46	
Cabrillo Power I, LLC	Cabrillo I	Encina CT	14	New
Dual Fuel Agreement Unit Extension Status *Extended Dual Fuel Contracts are to be effective January 1, 2008 thru December 31, 2008*				
Pacific Gas and Electric Company	Humboldt Bay	Humboldt Bay, Unit 1	52	Extended
		Humboldt Bay, Unit 2	53	
New Dual Fuel Agreement Units *Extended Dual Fuel Contracts are to be effective January 1, 2008 thru December 31, 2008*				
Cabrillo Power I LLC	Cabrillo I	Encina Unit 1	106	New
		Encina Unit 2	103	
		Encina Unit 3	109	
		Encina Unit 4	299	
		Encina Unit 5	329	

EXHIBIT D

Docket No. 07-AFC-6

CENTER FOR BIOLOGICAL DIVERSITY'S RESPONSE IN SUPPORT OF CITY OF CARLSBAD'S MOTION TO TAKE OFFICIAL NOTICE AND THE CENTER'S MOTION TO TAKE OFFICIAL NOTICE AND RE-OPEN THE EVIDENTIARY RECORD

October 15, 2010

Via Fed-Ex & E-mail

Mr. Randy Hickok
Managing Director Asset Management & Trading
Dynegy, Inc.
4140 Dublin Boulevard, Suite 100
Dublin, CA 94568

Dear Mr. Hickok:

By letter dated September 29, 2010, the California Independent System Operator Corporation (ISO) notified Dynegy, Inc. that it was extending the Reliability Must Run (RMR) Agreement applicable to Dynegy's South Bay Units 1, 2 and the CT (collectively, the South Bay units). Since then, the ISO has received new information about projected power demand in the San Diego local area, showing that local power requirements are lower than the California Energy Commission (CEC) had previously projected in its 2009 forecasts used in the ISO's 2011 Local Capacity Technical Analysis for 2011 and 2012. Additionally, on September 27, 2010, the San Diego area experienced a record peak demand of 4,684 MW. ISO staff analyzed the weather conditions behind this peak load event in light of the lower CEC forecast. This analysis reinforces the ISO's confidence in the accuracy of the recent, lower power demand projections for the area.

For these reasons, the ISO is pleased to inform Dynegy of its decision to rescind the September 29, 2010 notice of extension and the RMR status of the South Bay units will, therefore, terminate on December 31, 2010. We understand that RMR designation caused Dynegy some concern given, among other things, the age of the facilities and the community's long-standing desire and expectation to see the units closed and removed. With this notice, Dynegy is now free to proceed with decommissioning and demolition in accordance with its lease agreement with the Port of San Diego beginning January 1, 2011.

As you know, on June 11, 2010, the ISO filed a petition for review of the decision of the California Regional Water Quality Board for the San Diego Region denying an administrative extension of the National Pollutant Discharge Elimination System (NPDES) permit for South Bay Units 1 and 2. We will take steps promptly to withdraw that petition.

As you also know, a hearing on Dynegy's pending NPDES permit application for operation beyond December 31, 2010 is scheduled for November 17, 2010. We will be submitting comments on Monday, October 18, indicating that the ISO has reassessed the local reliability need for the South Bay units beyond 2010 and has determined that these units are no longer needed for RMR service beyond the current contract year.

The ISO appreciates the RMR service the South Bay units have provided over the years and we are pleased to be able to release them from service at the end of this year.

Sincerely,

Steve Berberich
Vice President and Chief Operating Officer

SBB/ag

cc: Joseph M. Paul (Dynegy, Inc.)
Daniel P. Thompson (Dynegy, Inc.)
R. Alan Padgett (Dynegy, Inc.)
James Walsh (SDG&E)
Victor Kruger (SDG&E)
Larry Chaset (CPUC)
The Honorable Cheryl Cox (City of Chula Vista)

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File

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A. Ulmer
C. Mamandur
P. Pettingill
G. Vanpelt
G. DeShazo
C. Micsa
A. Bhaumik
D. Timson
R. Kott
G. Grotta
J. Chipman

bcc: (Documentum)
Cabinet: Operations Support
Folder: Reliability Contracts\LARS\ 2011 LARS\Notices\
Filename: 100929 Dynegy South Bay RMR Extension

EXHIBIT E

2012
LOCAL CAPACITY TECHNICAL ANALYSIS

FINAL REPORT
AND STUDY RESULTS

April 29, 2011

Local Capacity Technical Study
Overview and Results

I. Executive Summary

This Report documents the results and recommendations of the 2012 Local Capacity Technical (LCT) Study. The LCT Study assumptions, processes, and criteria were discussed and recommended through the 2012 Local Capacity Technical Study Criteria, Methodology and Assumptions Stakeholder Meeting held on November 10, 2010. On balance, the assumptions, processes, and criteria used for the 2012 LCT Study mirror those used in the 2007-2011 LCT Studies, which were previously discussed and recommended through the LCT Study Advisory Group ("LSAG")[1], an advisory group formed by the CAISO to assist the CAISO in its preparation for performing prior LCT Studies.

The 2012 LCT study results are provided to the CPUC for consideration in its 2012 resource adequacy requirements program. These results will also be used by the CAISO for identifying the minimum quantity of local capacity necessary to meet the North American Electric Reliability Corporation (NERC) Reliability Criteria used in the LCT Study (this may be referred to as "Local Capacity Requirements" or "LCR") and for assisting in the allocation of costs of any CAISO procurement of capacity needed to achieve the Reliability Criteria notwithstanding the resource adequacy procurement of Load Serving Entities (LSEs).[2] In this regard, the 2012 LCT Study also provides additional information on sub-area needs and effectiveness factors (where applicable) in order to allow LSEs to engage in more informed procurement.

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[1] The LSAG consists of a representative cross-section of stakeholders, technically qualified to assess the issues related to the study assumptions, process and criteria of the existing LCT Study methodology and to recommend changes, where needed.

[2] For information regarding the conditions under which the CAISO may engage in procurement of local capacity and the allocation of the costs of such procurement, please see Sections 41 and 43 of the current CAISO Tariff, at: http://www.caiso.com/238a/238acd24167f0.html.

Below is a comparison of the 2012 vs. 2011 total LCR:

2012 Local Capacity Requirements

	Qualifying Capacity			2012 LCR Need Based on Category B			2012 LCR Need Based on Category C with operating procedure		
Local Area Name	**QF/ Muni (MW)**	**Market (MW)**	**Total (MW)**	**Existing Capacity Needed**	**Deficiency**	**Total (MW)**	**Existing Capacity Needed****	**Deficiency**	**Total (MW)**
Humboldt	54	168	222	159	0	**159**	190	22*	**212**
North Coast / North Bay	131	728	859	613	0	**613**	613	0	**613**
Sierra	1277	760	2037	1489	36*	**1525**	1685	289*	**1974**
Stockton	246	259	505	145	0	**145**	389	178*	**567**
Greater Bay	1312	5276	6588	3647	0	**3647**	4278	0	**4278**
Greater Fresno	356	2414	2770	1873	0	**1873**	1899	8*	**1907**
Kern	602	9	611	180	0	**180**	297	28*	**325**
LA Basin	4029	8054	12083	10865	0	**10865**	10865	0	**10865**
Big Creek/ Ventura	1191	4041	5232	3093	0	**3093**	3093	0	**3093**
San Diego	162	2925	3087	2849	0	**2849**	2849	95*	**2944**
Total	**9360**	**24634**	**33994**	**24913**	**36**	**24949**	**26158**	**620**	**26778**

2011 Local Capacity Requirements

	Qualifying Capacity			2011 LCR Need Based on Category B			2011 LCR Need Based on Category C with operating procedure		
Local Area Name	**QF/ Muni (MW)**	**Market (MW)**	**Total (MW)**	**Existing Capacity Needed**	**Deficiency**	**Total (MW)**	**Existing Capacity Needed****	**Deficiency**	**Total (MW)**
Humboldt	57	166	223	147	0	**147**	188	17*	**205**
North Coast / North Bay	133	728	861	734	0	**734**	734	0	**734**
Sierra	1057	759	1816	1330	313*	**1643**	1510	572*	**2082**
Stockton	267	259	526	374	0	**374**	459	223*	**682**
Greater Bay	1210	5296	6506	4036	0	**4036**	4804	74*	**4878**
Greater Fresno	485	2434	2919	2200	0	**2200**	2444	4*	**2448**
Kern	699	9	708	243	0	**243**	434	13*	**447**
LA Basin	4206	8103	12309	10589	0	**10589**	10589	0	**10589**
Big Creek/ Ventura	1196	4110	5306	2786	0	**2786**	2786	0	**2786**
San Diego	194	3227	3421	3146	0	**3146**	3146	61*	**3207**
Total	**9504**	**25091**	**34595**	**25585**	**313**	**25898**	**27094**	**964**	**28058**

* No local area is “overall deficient”. Resource deficiency values result from a few deficient sub-areas; and since there are no resources that can mitigate this deficiency the numbers are carried forward into the total area needs. Resource deficient sub-area implies that in order to comply with the criteria, at summer peak, load may be shed immediately after the first contingency.
** Since “deficiency” cannot be mitigated by any available resource, the “Existing Capacity Needed” will be split among LSEs on a load share ratio during the assignment of local area resource responsibility.

Overall, the LCR needs have decreased by more than 1200 MW or almost 5% from 2011 to 2012. The LCR needs have decreased in the following areas: North Coast/North Bay and Greater Bay Area due to downward trend for load; Sierra, Stockton, Fresno, Kern and San Diego due to downward trend for load and new transmission projects. The LCR needs have slightly increased in Humboldt due to load growth; LA Basin and Big Creek /Ventura due to small load growth as well as load allocation change (conform with new CEC forecast). The write-up for each Local Capacity Area lists important new projects included in the base cases as well as a description of reason for changes between 2012 and 2011 LCRs.

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II. Study Overview: Inputs, Outputs and Options

A. Objectives

As was the objective of the five previous annual LCT Studies, the intent of the 2012 LCT Study is to identify specific areas within the CAISO Balancing Authority Area that have limited import capability and determine the minimum generation capacity (MW) necessary to mitigate the local reliability problems in those areas.

B. Key Study Assumptions

1. Inputs and Methodology

The CAISO incorporated into its 2012 LCT study the same criteria, input assumptions and methodology that were incorporated into its previous years LCR studies. These inputs, assumptions and methodology were discussed and agreed to by stakeholders at the 2012 LCT Study Criteria, Methodology and Assumptions Stakeholder Meeting held on November 10, 2010.

The following table sets forth a summary of the approved inputs and methodology that have been used in the previous LCT studies as well as this 2012 LCT Study:

Summary Table of Inputs and Methodology Used in this LCT Study:

Issue:	How are they incorporated into this LCT study:
Input Assumptions:	
• Transmission System Configuration	The existing transmission system has been modeled, including all projects operational on or before June 1, of the study year and all other feasible operational solutions brought forth by the PTOs and as agreed to by the CAISO.
• Generation Modeled	The existing generation resources has been modeled and also includes all projects that will be on-line and commercial on or before June 1, of the study year
• Load Forecast	Uses a 1-in-10 year summer peak load forecast
Methodology:	
• Maximize Import Capability	Import capability into the load pocket has been maximized, thus minimizing the generation required in the load pocket to meet applicable reliability requirements.
• QF/Nuclear/State/Federal Units	Regulatory Must-take and similarly situated units like QF/Nuclear/State/Federal resources have been modeled on-line at qualifying capacity output values for purposes of this LCT Study.
• Maintaining Path Flows	Path flows have been maintained below all established path ratings into the load pockets, including the 500 kV. For clarification, given the existing transmission system configuration, the only 500 kV path that flows directly into a load pocket and will, therefore, be considered in this LCR Study is the South of Lugo transfer path flowing into the LA Basin.
Performance Criteria:	
• Performance Level B & C, including incorporation of PTO operational solutions	This LCT Study is being published based on Performance Level B and Performance Level C criterion, yielding the low and high range LCR scenarios. In addition, the CAISO will incorporate all new projects and other feasible and CAISO-approved operational solutions brought forth by the PTOs that can be operational on or before June 1, of the study year. Any such solutions that can reduce the need for procurement to meet the Performance Level C criteria will be incorporated into the LCT Study.
Load Pocket:	
• Fixed Boundary, including limited reference to published effectiveness factors	This LCT Study has been produced based on load pockets defined by a fixed boundary. The CAISO only publishes effectiveness factors where they are useful in facilitating procurement where excess capacity exists within a load pocket.

Further details regarding the 2012 LCT Study methodology and assumptions are provided in Section III, below.

C. Grid Reliability

Service reliability builds from grid reliability because grid reliability is reflected in the planning standards of the Western Electricity Coordinating Council ("WECC") that incorporate standards set by the North American Electric Reliability Council ("NERC") (collectively "NERC Planning Standards"). The NERC Planning Standards apply to the interconnected electric system in the United States and are intended to address the reality that within an integrated network, whatever one Balancing Authority Area does can affect the reliability of other Balancing Authority Areas. Consistent with the mandatory nature of the NERC Planning Standards, the CAISO is under a statutory obligation to ensure efficient use and reliable operation of the transmission grid consistent with achievement of the NERC Planning Standards.[3] The CAISO is further under an obligation, pursuant to its FERC-approved Transmission Control Agreement, to secure compliance with all "Applicable Reliability Criteria." Applicable Reliability Criteria consists of the NERC Planning Standards as well as reliability criteria adopted by the CAISO, in consultation with the CAISO's Participating Transmission Owners ("PTOs"), which affect a PTO's individual system.

The NERC Planning Standards define reliability on interconnected electric systems using the terms "adequacy" and "security." "Adequacy" is the ability of the electric systems to supply the aggregate electrical demand and energy requirements of their customers at all times, taking into account physical characteristics of the transmission system such as transmission ratings and scheduled and reasonably expected unscheduled outages of system elements. "Security" is the ability of the electric systems to withstand sudden disturbances such as electric short circuits or unanticipated loss of system elements. The NERC Planning Standards are organized by Performance Categories. Certain categories require that the grid operator not only ensure that grid integrity is maintained under certain adverse system conditions (e.g., security), but also that all customers continue to receive electric supply to meet demand (e.g., adequacy). In that case, grid reliability and service reliability would overlap. But

[3] Pub. Utilities Code § 345

there are other levels of performance where security can be maintained without ensuring adequacy.

D. Application of N-1, N-1-1, and N-2 Criteria

The CAISO will maintain the system in a safe operating mode at all times. This obligation translates into respecting the Reliability Criteria at all times, for example during normal operating conditions (N-0) the CAISO must protect for all single contingencies (N-1) and common mode (N-2) double line outages. Also, after a single contingency, the CAISO must re-adjust the system to support the loss of the next most stringent contingency. This is referred to as the N-1-1 condition.

The N-1-1 vs N-2 terminology was introduced only as a mere temporal differentiation between two existing NERC Category C events. N-1-1 represents NERC Category C3 (“category B contingency, manual system adjustment, followed by another category B contingency”). The N-2 represents NERC Category C5 (“any two circuits of a multiple circuit tower line”) as well as WECC-S2 (for 500 kV only) (“any two circuits in the same right-of-way”) with no manual system adjustment between the two contingencies.

E. Performance Criteria

As set forth on the Summary Table of Inputs and Methodology, this LCT Report is based on NERC Performance Level B and Performance Level C criterion. The NERC Standards refer mainly to thermal overloads. However, the CAISO also tests the electric system in regards to the dynamic and reactive margin compliance with the existing WECC standards for the same NERC performance levels. These Performance Levels can be described as follows:

a. <u>Performance Criteria- Category B</u>

Category B describes the system performance that is expected immediately following the loss of a single transmission element, such as a transmission circuit, a generator, or a transformer.

Category B system performance requires that all thermal and voltage limits must be within their "Applicable Rating," which, in this case, are the emergency ratings as generally determined by the PTO or facility owner. Applicable Rating includes a temporal element such that emergency ratings can only be maintained for certain duration. Under this category, load cannot be shed in order to assure the Applicable Ratings are met; however there is no guarantee that facilities are returned to within normal ratings or to a state where it is safe to continue to operate the system in a reliable manner such that the next element out will not cause a violation of the Applicable Ratings.

b. <u>Performance Criteria- Category C</u>

The NERC Planning Standards require system operators to "look forward" to make sure they safely prepare for the "next" N-1 following the loss of the "first" N-1 (stay within Applicable Ratings after the "next" N-1). This is commonly referred to as N-1-1. Because it is assumed that some time exists between the "first" and "next" element losses, operating personnel may make any reasonable and feasible adjustments to the system to prepare for the loss of the second element, including, operating procedures, dispatching generation, moving load from one substation to another to reduce equipment loading, dispatching operating personnel to specific station locations to manually adjust load from the substation site, or installing a "Special Protection Scheme" that would remove pre-identified load from service upon the loss of the "next " element.[4] All Category C requirements in this report refer to situations when in real time

[4] A Special Protection Scheme is typically proposed as an operational solution that does not require

(N-0) or after the first contingency (N-1) the system requires additional readjustment in order to prepare for the next worst contingency. In this time frame, load drop is not allowed per existing planning criteria.

Generally, Category C describes system performance that is expected following the loss of two or more system elements. This loss of two elements is generally expected to happen simultaneously, referred to as N-2. It should be noted that once the "next" element is lost after the first contingency, as discussed above under the Performance Criteria B, N-1-1 scenario, the event is effectively a Category C. As noted above, depending on system design and expected system impacts, the **planned and controlled** interruption of supply to customers (load shedding), the removal from service of certain generators and curtailment of exports may be utilized to maintain grid "security."

c. CAISO Statutory Obligation Regarding Safe Operation

The CAISO will maintain the system in a safe operating mode at all times. This obligation translates into respecting the Reliability Criteria at all times, for example during normal operating conditions **A (N-0)** the CAISO must protect for all single contingencies **B (N-1)** and common mode **C5 (N-2)** double line outages. As a further example, after a single contingency the CAISO must readjust the system in order to be able to support the loss of the next most stringent contingency **C3 (N-1-1)**.

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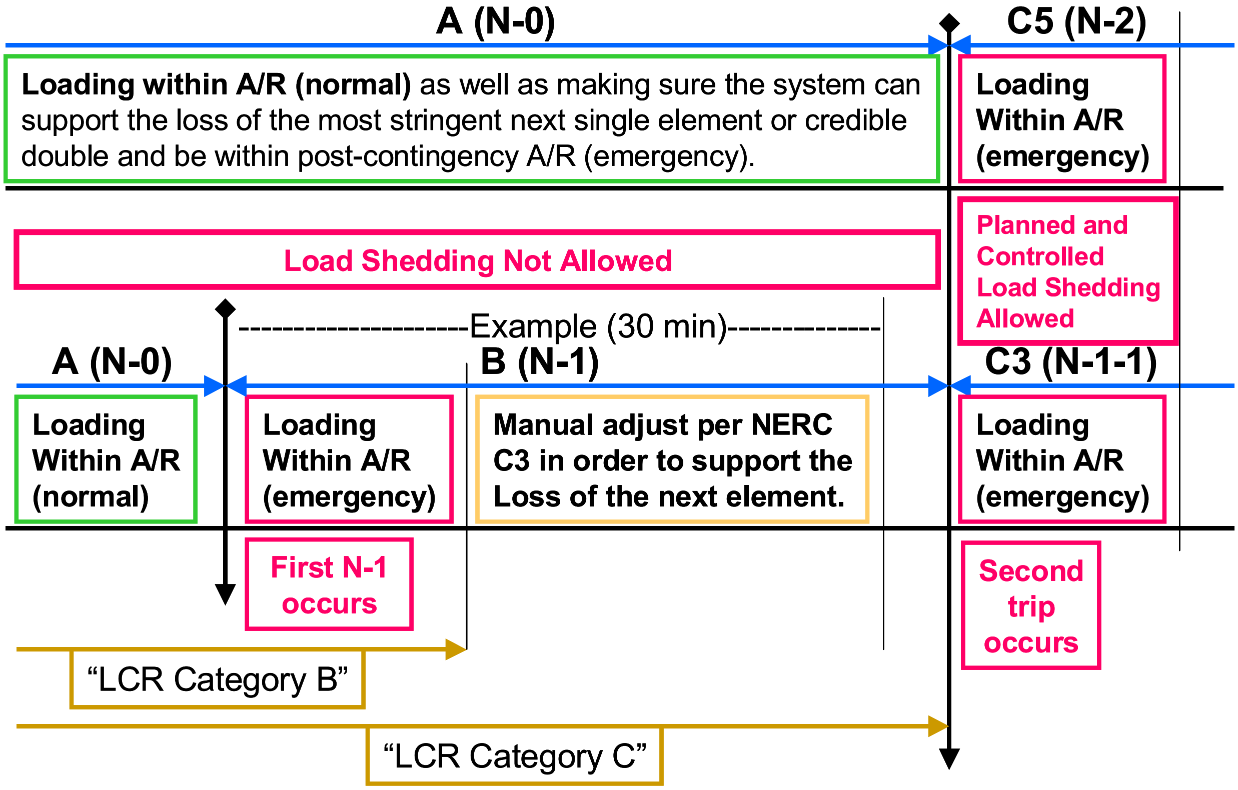
additional generation and permits operators to effectively prepare for the next event as well as ensure security should the next event occur. However, these systems have their own risks, which limit the extent to which they could be deployed as a solution for grid reliability augmentation. While they provide the value of protecting against the next event without the need for pre-contingency load shedding, they add points of potential failure to the transmission network. This increases the potential for load interruptions because sometimes these systems will operate when not required and other times they will not operate when needed.



The following definitions guide the CAISO's interpretation of the Reliability Criteria governing safe mode operation and are used in this LCT Study:

<u>Applicable Rating:</u>

This represents the equipment rating that will be used under certain contingency conditions.

<u>Normal rating</u> is to be used under normal conditions.

<u>Long-term emergency ratings</u>, if available, will be used in all emergency conditions as long as "system readjustment" is provided in the amount of time given (specific to each element) to reduce the flow to within the normal ratings. If not available normal rating is to be used.

<u>Short-term emergency ratings</u>, if available, can be used as long as "system readjustment" is provided in the "short-time" available in order to reduce the flow to

within the long-term emergency ratings where the element can be kept for another length of time (specific to each element) before the flow needs to be reduced the below the normal ratings. If not available long-term emergency rating should be used.

Temperature-adjusted ratings shall not be used because this is a year-ahead study not a real-time tool, as such the worst-case scenario must be covered. In case temperature-adjusted ratings are the only ratings available then the minimum rating (highest temperature) given the study conditions shall be used.

CAISO Transmission Register is the only official keeper of all existing ratings mentioned above.

Ratings for future projects provided by PTO and agree upon by the CAISO shall be used.

Other short-term ratings not included in the CAISO Transmission Register may be used as long as they are engineered, studied and enforced through clear operating procedures that can be followed by real-time operators.

Path Ratings need to be maintained in order for these studies to comply with the Minimum Operating Reliability Criteria and assure that proper capacity is available in order to operate the system in real-time.

Controlled load drop:

This is achieved with the use of a Special Protection Scheme.

Planned load drop:

This is achieved when the most limiting equipment has short-term emergency ratings AND the operators have an operating procedure that clearly describes the actions that need to be taken in order to shed load.

Special Protection Scheme:

All known SPS shall be assumed. New SPS must be verified and approved by the CAISO and must comply with the new SPS guideline described in the CAISO Planning Standards.

System Readjustment:

This represents the actions taken by operators in order to bring the system within a safe operating zone after any given contingency in the system.

<u>*Actions that can be taken as system readjustment after a single contingency (Category B):*</u>

1. System configuration change – based on validated and approved operating procedures
2. Generation re-dispatch
    a. Decrease generation (up to 1150 MW) – limit given by single contingency SPS as part of the CAISO Grid Planning standards (ISO G4)
    b. Increase generation – this generation will become part of the LCR need

<u>*Actions, which shall not be taken as system readjustment after a single contingency (Category B):*</u>

1. Load drop – based on the intent of the CAISO/WECC and NERC criteria for category B contingencies.

This is one of the most controversial aspects of the interpretation of the existing NERC criteria because the NERC Planning Standards footnote mentions that load shedding can be done after a category B event in certain local areas in order to maintain compliance with performance criteria. However, the main body of the criteria spells out that no dropping of load should be done following a single contingency. All stakeholders and the CAISO agree that no involuntary interruption of load should be done immediately after a single contingency. Further, the CAISO and stakeholders now agree on the viability of dropping load as part of the system readjustment period – in order to protect for the next most limiting contingency. After a single contingency, it is understood that the system is in a Category B condition and the system should be planned based on the body of the criteria with no shedding of load regardless of whether it is done immediately or in 15-30 minute after the original contingency. Category C conditions only arrive after the second contingency has happened; at that point in time, shedding load is allowed in a planned and controlled manner.

A robust California transmission system should be, and under the LCT Study is being, planned based on the main body of the criteria, not the footnote regarding Category B contingencies. Therefore, if there are available resources in the area, they are looked to meet reliability needs (and included in the LCR requirement) before resorting to involuntary load curtailment. The footnote may be applied for criteria compliance issues only where there are no resources available in the area.

Time allowed for manual readjustment:

This is the amount of time required for the operator to take all actions necessary to prepare the system for the next contingency. This time should be less than 30 minutes, based on existing CAISO Planning Standards.

This is a somewhat controversial aspect of the interpretation of existing criteria. This item is very specific in the CAISO Planning Standards. However, some will argue that 30 minutes only allows generation re-dispatch and automated switching where remote control is possible. If remote capability does not exist, a person must be dispatched in the field to do switching and 30 minutes may not allow sufficient time. If approved, an exemption from the existing time requirements may be given for small local areas with very limited exposure and impact, clearly described in operating procedures, and only until remote controlled switching equipment can be installed.

F. The Two Options Presented In This LCT Report

This LCT Study sets forth different solution "options" with varying ranges of potential service reliability consistent with CAISO's Reliability Criteria. The CAISO applies Option 2 for its purposes of identifying necessary local capacity needs and the corresponding potential scope of its backstop authority. Nevertheless, the CAISO continues to provide Option 1 as a point of reference for the CPUC and Local Regulatory Authorities in considering procurement targets for their jurisdictional LSEs.

1. Option 1- Meet Performance Criteria Category B

Option 1 is a service reliability level that reflects generation capacity that must be available to comply with reliability standards immediately after a NERC Category B given that load cannot be removed to meet this performance standard under Reliability Criteria. However, this capacity amount implicitly relies on load interruption as the **only means** of meeting any Reliability Criteria that is beyond the loss of a single transmission element (N-1). These situations will likely require substantial load interruptions in order to maintain system continuity and alleviate equipment overloads prior to the actual occurrence of the second contingency.[5]

2. Option 2- Meet Performance Criteria Category C and Incorporate Suitable Operational Solutions

Option 2 is a service reliability level that reflects generation capacity that is needed to readjust the system to prepare for the loss of a second transmission element (N-1-1) using generation capacity *after* considering all reasonable and feasible operating solutions (including those involving customer load interruption) developed and approved by the CAISO, in consultation with the PTOs. Under this option, there is no expected load interruption to end-use customers under normal or single contingency conditions as the CAISO operators prepare for the second contingency. However, the customer load may be interrupted in the event the second contingency occurs.

As noted, Option 2 is the local capacity level that the CAISO requires to reliably operate the grid per NERC, WECC and CAISO standards. As such, the CAISO recommends adoption of this Option to guide resource adequacy procurement.

III. Assumption Details: How the Study was Conducted

A. System Planning Criteria

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5 This potential for pre-contingency load shedding also occurs because real time operators must prepare for the loss of a common mode N-2 at all times.

The following table provides a comparison of system planning criteria, based on the NERC performance standards, used in the study:

Table 4: Criteria Comparison

Contingency Component(s)	ISO Grid Planning Criteria	Old RMR Criteria	Local Capacity Criteria
A – No Contingencies	X	X	X
B – Loss of a single element			
1. Generator (G-1)	X	X	X[1]
2. Transmission Circuit (L-1)	X	X	X[1]
3. Transformer (T-1)	X	X[2]	X[1,2]
4. Single Pole (dc) Line	X	X	X[1]
5. G-1 system readjusted L-1	X	X	X
C – Loss of two or more elements			
1. Bus Section	X		
2. Breaker (failure or internal fault)	X		
3. L-1 system readjusted G-1	X		X
3. G-1 system readjusted T-1 or T-1 system readjusted G-1	X		X
3. L-1 system readjusted T-1 or T-1 system readjusted L-1	X		X
3. G-1 system readjusted G-1	X		X
3. L-1 system readjusted L-1	X		X
3. T-1 system readjusted T-1	X		
4. Bipolar (dc) Line	X		X
5. Two circuits (Common Mode) L-2	X		X
6. SLG fault (stuck breaker or protection failure) for G-1	X		
7. SLG fault (stuck breaker or protection failure) for L-1	X		
8. SLG fault (stuck breaker or protection failure) for T-1	X		
9. SLG fault (stuck breaker or protection failure) for Bus section	X		
WECC-S3. Two generators (Common Mode) G-2	X[3]		X
D – Extreme event – loss of two or more elements			
Any B1-4 system readjusted (Common Mode) L-2	X[4]		X[3]
All other extreme combinations D1-14.	X[4]		

1 System must be able to readjust to a safe operating zone in order to be able to support the loss of the next contingency.
2 A thermal or voltage criterion violation resulting from a transformer outage may not be cause for a local area reliability requirement if the violation is considered marginal (e.g. acceptable loss of facility life or low voltage), otherwise, such a violation will necessitate creation of a requirement.
3 Evaluate for risks and consequence, per NERC standards. No voltage collapse or dynamic instability allowed.
4 Evaluate for risks and consequence, per NERC standards.

A significant number of simulations were run to determine the most critical contingencies within each Local Capacity Area. Using power flow, post-transient load flow, and stability assessment tools, the system performance results of all the contingencies that were studied were measured against the system performance requirements defined by the criteria shown in Table 4. Where the specific system performance requirements were not met, generation was adjusted such that the minimum amount of generation required to meet the criteria was determined in the Local Capacity Area. The following describes how the criteria were tested for the specific type of analysis performed.

1. Power Flow Assessment:

Contingencies	Thermal Criteria[3]	Voltage Criteria[4]
Generating unit [1, 6]	Applicable Rating	Applicable Rating
Transmission line [1, 6]	Applicable Rating	Applicable Rating
Transformer [1, 6]	Applicable Rating[5]	Applicable Rating[5]
(G-1)(L-1) [2, 6]	Applicable Rating	Applicable Rating
Overlapping [6, 7]	Applicable Rating	Applicable Rating

[1] All single contingency outages (i.e. generating unit, transmission line or transformer) will be simulated on Participating Transmission Owners' local area systems.

[2] Key generating unit out, system readjusted, followed by a line outage. This over-lapping outage is considered a single contingency within the ISO Grid Planning Criteria. Therefore, load dropping for an overlapping G-1, L-1 scenario is not permitted.

[3] Applicable Rating – Based on ISO Transmission Register or facility upgrade plans including established Path ratings.

[4] Applicable Rating – ISO Grid Planning Criteria or facility owner criteria as appropriate including established Path ratings.

[5] A thermal or voltage criterion violation resulting from a transformer outage may not be cause for a local area reliability requirement if the violation is considered marginal (e.g. acceptable loss of facility life or low voltage), otherwise, such a violation will necessitate creation of a requirement.

[6] Following the first contingency (N-1), the generation must be sufficient to allow the operators to bring the system back to within acceptable (normal) operating range (voltage and loading) and/or appropriate OTC following the studied outage conditions.

[7] During normal operation or following the first contingency (N-1), the generation must be sufficient to allow the operators to prepare for the next worst N-1 or common mode N-2 without pre-contingency interruptible or firm load shedding. SPS/RAS/Safety Nets may be utilized to satisfy the criteria after the second N-1

or common mode N-2 except if the problem is of a thermal nature such that short-term ratings could be utilized to provide the operators time to shed either interruptible or firm load. T-2s (two transformer bank outages) would be excluded from the criteria.

2. Post Transient Load Flow Assessment:

Contingencies **Selected** [1]	Reactive Margin Criteria [2] **Applicable Rating**

[1] If power flow results indicate significant low voltages for a given power flow contingency, simulate that outage using the post transient load flow program. The post-transient assessment will develop appropriate Q/V and/or P/V curves.

[2] Applicable Rating – positive margin based on the higher of imports or load increase by 5% for N-1 contingencies, and 2.5% for N-2 contingencies.

3. Stability Assessment:

Contingencies **Selected** [1]	Stability Criteria [2] **Applicable Rating**

[1] Base on historical information, engineering judgment and/or if power flow or post transient study results indicate significant low voltages or marginal reactive margin for a given contingency.

[2] Applicable Rating – ISO Grid Planning Criteria or facility owner criteria as appropriate.

B. Load Forecast

1. System Forecast

The California Energy Commission (CEC) derives the load forecast at the system and Participating Transmission Owner (PTO) levels. This relevant CEC forecast is then distributed across the entire system, down to the local area, division and substation level. The PTOs use an econometric equation to forecast the system load. The predominant parameters affecting the system load are (1) number of households, (2) economic activity (gross metropolitan products, GMP), (3) temperature and (4) increased energy efficiency and distributed generation programs.

2. Base Case Load Development Method

The method used to develop the base case loads is a melding process that extracts, adjusts and modifies the information from the system, distribution and municipal utility forecasts. The melding process consists of two parts: Part 1 deals with the PTO load and Part 2 deals with the municipal utility load. There may be small differences between the methodologies used by each PTO to disaggregate the CEC load forecast to their level of local area as well as bar-bus model.

a. PTO Loads in Base Case

The methods used to determine the PTO loads are, for the most part, similar. One part of the method deals with the determination of the division[6] loads that would meet the requirements of 1-in-5 or 1-in-10 system or area base cases and the other part deals with the allocation of the division load to the transmission buses.

i. Determination of division loads

The annual division load is determined by summing the previous year division load and the current division load growth. Thus, the key steps are the determination of the initial year division load and the annual load growth. The initial year for the base case development method is based heavily on recorded data. The division load growth in the system base case is determined in two steps. First, the total PTO load growth for the year is determined, as the product of the PTO load and the load growth rate from the system load forecast. Then this total PTO load growth is allocated to the division, based on the relative magnitude of the load growth projected for the divisions by the distribution planners. For example, for the 1-in-10 area base case, the division load growth determined for the system base case is adjusted to the 1-in-10 temperature using the load temperature relation determined from the latest peak load and temperature data of the division.

[6] Each PTO divides its territory in a number of smaller area named divisions. These are usually smaller and compact areas that have the same temperature profile.

ii. Allocation of division load to transmission bus level

Since the base case loads are modeled at the various transmission buses, the division loads developed must be allocated to those buses. The allocation process is different depending on the load types. For the most part, each PTO classifies its loads into four types: conforming, non-conforming, self-generation and generation-plant loads. Since the non-conforming and self-generation loads are assumed to not vary with temperature, their magnitude would be the same in the system or area base cases of the same year. The remaining load (the total division load developed above, less the quantity of non-conforming and self-generation load) is the conforming load. The remaining load is allocated to the transmission buses based on the relative magnitude of the distribution forecast. The summation of all base case loads is generally higher than the load forecast because some load, i.e., self-generation and generation-plant, are behind the meter and must be modeled in the base cases. However, for the most part, metered or aggregated data with telemetry is used to come up with the load forecast.

b. Municipal Loads in Base Case

The municipal utility forecasts that have been provided to the CEC and PTOs for the purposes of their base cases were also used for this study.

C. Power Flow Program Used in the LCT analysis

The technical studies were conducted using General Electric's Power System Load Flow (GE PSLF) program version 17.0. This GE PSLF program is available directly from GE or through the Western System Electricity Council (WECC) to any member.

To evaluate Local Capacity Areas, the starting base case was adjusted to reflect the latest generation and transmission projects as well as the one-in-ten-year peak load forecast for each Local Capacity Area as provided to the CAISO by the PTOs.

Electronic contingency files provided by the PTOs were utilized to perform the numerous contingencies required to identify the LCR. These contingency files include remedial action and special protection schemes that are expected to be in operation during the year of study. An CAISO created EPCL (a GE programming language contained within the GE PSLF package) routine was used to run the combination of contingencies; however, other routines are available from WECC with the GE PSFL package or can be developed by third parties to identify the most limiting combination of contingencies requiring the highest amount of generation within the local area to maintain power flows within applicable ratings.

IV. Local Capacity Requirement Study Results

A. Summary of Study Results

LCR is defined as the amount of generating capacity that is needed within a Local Capacity Area to reliably serve the load located within this area. The results of the CAISO's analysis are summarized in the Executive Summary Tables.

Table 5: 2012 Local Capacity Needs vs. Peak Load and Local Area Generation

	2012 Total LCR (MW)	Peak Load (1 in10) (MW)	2012 LCR as % of Peak Load	Total Dependable Local Area Generation (MW)	2012 LCR as % of Total Area Generation
Humboldt	212	210	101%	222	95%**
North Coast/North Bay	613	1420	43%	859	71%
Sierra	1974	1816	109%	2037	97%**
Stockton	567	1086	52%	505	112%**
Greater Bay	4278	9954	43%	6588	65%
Greater Fresno	1907	3120	61%	2770	69%**
Kern	325	1110	29%	611	53%**
LA Basin	10865	19931	55%	12083	90%
Big Creek/Ventura	3093	4693	66%	5232	59%
San Diego	2944	4844	61%	3087	95%**
Total	**26,778**	**48184***	**56%***	**33,994**	**79%**

Table 6: 2011 Local Capacity Needs vs. Peak Load and Local Area Generation

	2011 Total LCR (MW)	Peak Load (1 in10) (MW)	2011 LCR as % of Peak Load	Total Dependable Local Area Generation (MW)	2011 LCR as % of Total Area Generation
Humboldt	205	206	100%	223	92%**
North Coast/North Bay	734	1574	47%	861	85%
Sierra	2082	1977	105%	1816	115%**
Stockton	682	1163	59%	526	130%**
Greater Bay	4878	10322	47%	6506	75%**
Greater Fresno	2448	3306	74%	2919	84%**
Kern	447	1387	32%	708	63%**
LA Basin	10589	20223	52%	12309	86%
Big Creek/Ventura	2786	4648	60%	5306	53%
San Diego	3207	5036	64%	3421	94%**
Total	**28,058**	**49842***	**56%***	**34,595**	**81%**

* Value shown only illustrative, since each local area peaks at a time different from the system coincident peak load.

** Generation deficient LCA (or with sub-area that is deficient) – deficiency included in LCR. Generator deficient area implies that in order to comply with the criteria, at summer peak, load may be shed immediately after the first contingency.

Tables 5 and 6 shows how much of the Local Capacity Area load is dependent on local generation and how much local generation must be available in order to serve the load in those Local Capacity Areas in a manner consistent with the Reliability Criteria. These tables also indicate where new transmission projects, new generation additions or demand side management programs would be most useful in order to reduce the dependency on existing, generally older and less efficient local area generation.

The term "Qualifying Capacity" used in this report is the latest "Net Qualifying Capacity" ("NQC") posted on the CAISO web site at:

http://www.caiso.com/1796/179688b22c970.html

The NQC list includes the area (if applicable) where each resource is located for units already operational. Neither the NQC list nor this report incorporates Demand Side Management programs and their related NQC. Units scheduled to become operational before 6/1/2012 have been included in this 2012 LCR Report and added to the total NQC values for those respective areas (see detail write-up for each area).

The first column, "Qualifying Capacity," reflects two sets of generation. The first set is comprised of generation that would normally be expected to be on-line such as Municipal generation and Regulatory Must-take generation (state, federal, QFs, wind and nuclear units). The second set is "market" generation. The second column, "2012 LCR Requirement Based on Category B" identifies the local capacity requirements, and deficiencies that must be addressed, in order to achieve a service reliability level based on Performance Criteria- Category B. The third column, "2012 LCR Requirement Based on Category C with Operating Procedure", sets forth the local capacity requirements, and deficiencies that must be addressed, necessary to attain a service reliability level based on Performance Criteria-Category C with operational solutions.

B. Summary of Zonal Needs

Based on the existing import allocation methodology, the only major 500 kV constraint not accounted for is path 26 (Midway-Vincent). ***The current method allocates capacity on path 26 similar to the way imports are allocated to LSEs.*** The total resources needed (based on the latest CEC load forecast) in each the two relevant zones, SP26 and NP26 is:

Zone	Load Forecast (MW)	15% reserves (MW)	(-) Allocated imports (MW)	(-) Allocated Path 26 Flow (MW)	Total Zonal Resource Need (MW)
SP26	27442	4116	-8849	-3750	**18959**
NP26=NP15+ZP26	21174	3176	-4724	-2902	**16724**

Where:

<u>Load Forecast</u> is the most recent 1 in 2 CEC forecast for year 2012.

<u>Reserve Margin</u> is the minimum CPUC approved planning reserve margin of 15%.

<u>Allocated Imports</u> are the actual 2011 Available Import Capability for loads in the CAISO control area numbers that are not expected to change much by 2012 because there are no additional import transmission additions to the grid between now and summer of 2012.

Allocated Path 26 flow The CAISO determines the amount of Path 26 transfer capacity available for RA counting purposes after accounting for (1) Existing Transmission Contracts (ETCs) that serve load outside the CAISO Balancing Area[7] and (2) loop flow[8] from the maximum path 26 rating of 4000 MW (North-to-South) and 3000 MW (South-to-North).

Both NP 26 and SP 26 load forecast, import allocation and zonal results refer to the CAISO Balancing Area only. This is done in order to be consistent with the import allocation methodology.

All resources that are counted as part of the Local Area Capacity Requirements fully count toward the Zonal Need. The local areas of San Diego, LA Basin and Big Creek/Ventura are all situated in SP26 and the remaining local areas are in NP26.

Changes compared to last year's results:

- The load forecast went down in Southern California by about 800 MW and down in Northern California by about 900 MW.
- The Import Allocations went up in Southern California by about 300 MW and down in Northern California by about 150 MW.
- The Path 26 transfer capability has not changed and is not envisioned to change in the near future. As such, the LSEs should assume that their load/share ratio allocation for path 26 will stay at the same levels as 2011. If there are any changes, they will be heavily influenced by the pre-existing "grandfathered contracts" and when they expire most of the LSEs will likely see their load share ratio going up, while the owners of these grandfathered contracts may see their share decreased to the load-share ratio.

[7] The transfer capability on Path 26 must be derated to accommodate ETCs on Path 26 that are used to serve load outside of the CAISO Balancing Area. These particular ETCs represent physical transmission capacity that cannot be allocated to LSEs within the CAISO Balancing Area.

[8] "Loop flow" is a phenomenon common to large electric power systems like the Western Electricity Coordinating Council. Power is scheduled to flow point-to-point on a Day-ahead and Hour-ahead basis through the CAISO. However, electric grid physics prevails and the actual power flow in real-time will differ from the pre-arranged scheduled flows. Loop flow is real, physical energy and it uses part of the available transfer capability on a path. If not accommodated, loop flow will cause overloading of lines, which can jeopardize the security and reliability of the grid.

C. Summary of Results by Local Area

Each Local Capacity Area's overall requirement is determined by also achieving each sub-area requirement. Because these areas are a part of the interconnected electric system, the total for each Local Capacity Area is not simply a summation of the sub-area needs. For example, some sub-areas may overlap and therefore the same units may count for meeting the needs in both sub-areas.

1. Humboldt Area

<u>Area Definition</u>

The transmission tie lines into the area include:

1) Bridgeville-Cottonwood 115 kV line #1
2) Humboldt-Trinity 115 kV line #1
3) Willits-Garberville 60 kV line #1
4) Trinity-Maple Creek 60 kV line #1

The substations that delineate the Humboldt Area are:

1) Bridgeville and Low Gap are in Cottonwood and First Glen are out
2) Humboldt is in Trinity is out
3) Willits and Lytonville are out, Kekawaka and Garberville are in
4) Trinity is out, Ridge Cabin and Maple Creek are in

Total 2012 busload within the defined area: 200 MW with 10 MW of losses resulting in total load + losses of 210 MW.

Total units and qualifying capacity available in this area:

MKT/SCHED RESOURCE ID	BUS #	BUS NAME	kV	NQC	UNIT ID	LCR SUB-AREA NAME	NQC Comments	CAISO Tag
BRDGVL_7_BAKER				0.00		None	Not modeled Aug NQC	QF/Selfgen
FAIRHV_6_UNIT	31150	FAIRHAVN	13.8	14.49	1	Humboldt 60 kV	Aug NQC	QF/Selfgen

FTSWRD_7_QFUNTS				0.40		Humboldt 60 kV	Not modeled Aug NQC	QF/Selfgen
HUMBPP_1_UNITS3	31180	HUMB_G1	13.8	16.76	1	None		Market
HUMBPP_1_UNITS3	31180	HUMB_G1	13.8	16.76	2	None		Market
HUMBPP_1_UNITS3	31180	HUMB_G1	13.8	16.76	3	None		Market
HUMBPP_1_UNITS3	31180	HUMB_G1	13.8	16.77	4	None		Market
HUMBPP_6_UNITS1	31181	HUMB_G2	13.8	17.00	5	Humboldt 60 kV		Market
HUMBPP_6_UNITS1	31181	HUMB_G2	13.8	16.99	6	Humboldt 60 kV		Market
HUMBPP_6_UNITS2	31182	HUMB_G2	13.8	16.83	8	Humboldt 60 kV		Market
HUMBPP_6_UNITS2	31182	HUMB_G2	13.8	16.83	9	Humboldt 60 kV		Market
HUMBPP_6_UNITS2	31182	HUMB_G2	13.8	16.83	10	Humboldt 60 kV		Market
HUMBSB_1_QF				0.00		None	Not modeled Aug NQC	QF/Selfgen
KEKAWK_6_UNIT	31166	KEKAWAK	9.1	0.00	1	Humboldt 60 kV	Aug NQC	QF/Selfgen
LAPAC_6_UNIT	31158	LP SAMOA	12.5	20.00	1	Humboldt 60 kV		QF/Selfgen
PACLUM_6_UNIT	31152	PAC.LUMB	13.8	7.42	1	Humboldt 60 kV	Aug NQC	QF/Selfgen
PACLUM_6_UNIT	31152	PAC.LUMB	13.8	7.41	2	Humboldt 60 kV	Aug NQC	QF/Selfgen
PACLUM_6_UNIT	31153	PAC.LUMB	2.4	4.45	3	Humboldt 60 kV	Aug NQC	QF/Selfgen
WLLWCR_6_CEDRFL				0.00		Humboldt 60 kV	Not modeled Aug NQC	QF/Selfgen
HUMBPP_6_UNITS1	31181	HUMB_G2	13.8	16.60	7	Humboldt 60 kV	No NQC - Pmax	Market
ULTPBL_6_UNIT 1	31156	ULTRAPWR	12.5	0.00	1	Humboldt 60 kV	Energy Only	Market

Major new projects modeled:

1. Humboldt Bay Repower
2. Humboldt Reactive Support
3. Blue Lake generation project (energy only 0 MW NQC)

Critical Contingency Analysis Summary

Humboldt 60 kV Sub-area:

The most critical contingency for the Humboldt 60 kV Sub-area area is the outage of the Humboldt 115/60 Transformer and one of the gen tie-line connecting the new Humboldt Bay units (on 60 kV side). The area limitation is the overload on the parallel Humboldt

115/60 kV Transformer. This contingency establishes a LCR of 177 MW in 2012 (includes 54 MW of QF/Selfgen generation as well as 22 MW of deficiency) as the minimum capacity necessary for reliable load serving capability within this area.

The most critical single contingency is the outage of the Humboldt 115/60 kV Transformer. The limitation is thermal overload on the parallel Humboldt 115/60 kV Transformer. This limiting contingency establishes a LCR of 129 MW in 2012 (includes 54 MW of QF/Selfgen generation).

Effectiveness factors:

The following table has units within the Humboldt 60 kV Sub-area area with at least 5% effective to the above-mentioned constraint.

Gen Bus	Gen Name	Gen ID	Eff Fctr (%)
31150	FAIRHAVN	1	73
31158	LP SAMOA	1	73
31182	HUMB_G3	10	68
31182	HUMB_G3	9	68
31182	HUMB_G3	8	68
31181	HUMB_G2	7	68
31181	HUMB_G2	6	68
31181	HUMB_G2	5	68
31180	HUMB_G1	4	-14
31180	HUMB_G1	3	-14
31180	HUMB_G1	2	-14
31180	HUMB_G1	1	-14
31152	PAC.LUMB	1	40
31152	PAC.LUMB	2	40
31153	PAC.LUMB	3	40

Humboldt overall:

The most critical contingency for the Humboldt area is the outage of the Bridgeville-Cottonwood 115 kV Line overlapping with an outage of one of the tie-line connecting the new Humboldt Bay units on the 115 kV side. The area limitation is the overload on the Humboldt – Trinity 115 kV Line. This contingency establishes a LCR of 190 MW in 2012 (includes 54 MW of QF/Selfgen generation) as the minimum capacity necessary for reliable load serving capability within this area.

For the single contingency, the most critical one is an outage of the Bridgeville-Cottonwood 115 kV Line when one of the Humboldt Bay Power Plant units connected to the 115 kV bus is out of service. The limitation is the overload on the Humboldt – Trinity 115 kV Line. This limiting contingency establishes a LCR of 159 MW in 2012 (includes 54 MW of QF/Selfgen generation).

Effectiveness factors:

The following table has units within the Humboldt Overall system with at least 5% effective to the above-mentioned constraint

Gen Bus	Gen Name	Gen ID	Eff Fctr (%)
31150	FAIRHAVN	1	58
31158	LP SAMOA	1	58
31182	HUMB_G3	10	57
31182	HUMB_G3	9	57
31182	HUMB_G3	8	57
31181	HUMB_G2	7	57
31181	HUMB_G2	6	57
31181	HUMB_G2	5	57
31180	HUMB_G1	4	59
31180	HUMB_G1	3	59
31180	HUMB_G1	2	59
31180	HUMB_G1	1	59
31152	PAC.LUMB	1	52
31152	PAC.LUMB	2	52
31153	PAC.LUMB	3	52

Changes compared to last year's results:

The Humboldt Repowering Project (HBPP) was modeled an on-line in both 2011 and 2012 LCR studies. Two new transmission projects, the Maple Creek and Garberville Reactive support projects were modeled in 2011 studies, but not in 2012 because these projects were delayed past the 2012 peak. The overall load is expected to increase by 4 MW from 2011 to 2012 the overall LCR need has increased by 6 MW and the LCR resource need increased by 2 MW. The limiting outage and limiting facilities were the same as in the 2011 LCR.

Humboldt Overall Requirements:

2012	QF/Selfgen (MW)	Muni (MW)	Market (MW)	Max. Qualifying Capacity (MW)
Available generation	54	0	168	222

2012	Existing Generation Capacity Needed (MW)	Deficiency (MW)	Total MW LCR Need
Category B (Single)[9]	159	0	159
Category C (Multiple)[10]	190	22	212

2. North Coast / North Bay Area

<u>Area Definition</u>

The North Coast/North Bay Area is composed of three sub-areas and the generation requirements within them. The transmission tie facilities coming into the North Coast/North Bay area are:

1) Cortina-Mendocino 115 kV Line
2) Cortina-Eagle Rock 115 kV Line
3) Willits-Garberville 60 kV line #1
4) Vaca Dixon-Lakeville 230 kV line #1
5) Tulucay-Vaca Dixon 230 kV line #1
6) Lakeville-Sobrante 230 kV line #1
7) Ignacio-Sobrante 230 kV line #1

The substations that delineate the North Coast/North Bay area are:

1) Cortina is out Mendocino and Indian Valley are in
2) Cortina is out, Eagle Rock, Highlands and Homestake are in
3) Willits and Lytonville are in, Garberville and Kekawaka are out
4) Vaca Dixon is out Lakeville is in

[9] A single contingency means that the system will be able the survive the loss of a single element, however the operators will not have any means (other then load drop) in order to bring the system within a safe operating zone and get prepared for the next contingency as required by MORC.
[10] Multiple contingencies means that the system will be able the survive the loss of a single element, and the operators will have enough generation (other operating procedures) in order to bring the system within a safe operating zone and get prepared for the next contingency as required by MORC.

5) Tulucay is in Vaca Dixon is out
6) Lakeville is in, Sobrante is out
7) Ignacio is in, Sobrante and Crocket are out

Total 2012 busload within the defined area: 1386 MW with 34 MW of losses resulting in total load + losses of 1420 MW.

Total units and qualifying capacity available in this area are shown in the following table:

MKT/SCHED RESOURCE ID	BUS #	BUS NAME	kV	NQC	UNIT ID	LCR SUB-AREA NAME	NQC Comments	CAISO Tag
ADLIN_1_UNITS	31435	GEO.ENGY	9.1	8.00	1	Eagle Rock, Fulton, Lakeville		Market
ADLIN_1_UNITS	31435	GEO.ENGY	9.1	8.00	2	Eagle Rock, Fulton, Lakeville		Market
BEARCN_2_UNITS	31402	BEAR CAN	13.8	6.50	1	Fulton, Lakeville		Market
BEARCN_2_UNITS	31402	BEAR CAN	13.8	6.50	2	Fulton, Lakeville		Market
FULTON_1_QF				0.05		Fulton, Lakeville	Not modeled Aug NQC	QF/Selfgen
GEYS11_7_UNIT11	31412	GEYSER11	13.8	60.00	1	Eagle Rock, Fulton, Lakeville		Market
GEYS12_7_UNIT12	31414	GEYSER12	13.8	50.00	1	Fulton, Lakeville		Market
GEYS13_7_UNIT13	31416	GEYSER13	13.8	56.00	1	Lakeville		Market
GEYS14_7_UNIT14	31418	GEYSER14	13.8	50.00	1	Fulton, Lakeville		Market
GEYS16_7_UNIT16	31420	GEYSER16	13.8	49.00	1	Fulton, Lakeville		Market
GEYS17_2_BOTRCK	31421	BOTTLERK	13.8	14.70	1	Fulton, Lakeville		Market
GEYS17_7_UNIT17	31422	GEYSER17	13.8	47.00	1	Fulton, Lakeville		Market
GEYS18_7_UNIT18	31424	GEYSER18	13.8	45.00	1	Lakeville		Market
GEYS20_7_UNIT20	31426	GEYSER20	13.8	40.00	1	Lakeville		Market
GYS5X6_7_UNITS	31406	GEYSR5-6	13.8	40.00	1	Eagle Rock, Fulton, Lakeville		Market
GYS5X6_7_UNITS	31406	GEYSR5-6	13.8	40.00	2	Eagle Rock, Fulton, Lakeville		Market
GYS7X8_7_UNITS	31408	GEYSER78	13.8	38.00	1	Eagle Rock, Fulton, Lakeville		Market

GYS7X8_7_UNITS	31408	GEYSER78	13.8	38.00	2	Eagle Rock, Fulton, Lakeville		Market
GYSRVL_7_WSPRNG				1.68		Fulton, Lakeville	Not modeled Aug NQC	QF/Selfgen
HIWAY_7_ACANYN				1.04		Lakeville	Not modeled Aug NQC	QF/Selfgen
IGNACO_1_QF				0.00		Lakeville	Not modeled Aug NQC	QF/Selfgen
INDVLY_1_UNITS	31436	INDIAN V	9.1	0.81	1	Eagle Rock, Fulton, Lakeville	Aug NQC	QF/Selfgen
MONTPH_7_UNITS	32700	MONTICLO	9.1	3.90	1	Fulton, Lakeville	Aug NQC	QF/Selfgen
MONTPH_7_UNITS	32700	MONTICLO	9.1	3.90	2	Fulton, Lakeville	Aug NQC	QF/Selfgen
MONTPH_7_UNITS	32700	MONTICLO	9.1	0.93	3	Fulton, Lakeville	Aug NQC	QF/Selfgen
NAPA_2_UNIT				0.02		Lakeville	Not modeled Aug NQC	QF/Selfgen
NCPA_7_GP1UN1	38106	NCPA1GY1	13.8	31.00	1	Lakeville	Aug NQC	MUNI
NCPA_7_GP1UN2	38108	NCPA1GY2	13.8	28.00	1	Lakeville	Aug NQC	MUNI
NCPA_7_GP2UN3	38110	NCPA2GY1	13.8	0.00	1	Fulton, Lakeville	Aug NQC	MUNI
NCPA_7_GP2UN4	38112	NCPA2GY2	13.8	52.73	1	Fulton, Lakeville	Aug NQC	MUNI
POTTER_6_UNITS	31433	POTTRVLY	2.4	4.70	1	Eagle Rock, Fulton, Lakeville	Aug NQC	Market
POTTER_6_UNITS	31433	POTTRVLY	2.4	2.25	3	Eagle Rock, Fulton, Lakeville	Aug NQC	Market
POTTER_6_UNITS	31433	POTTRVLY	2.4	2.25	4	Eagle Rock, Fulton, Lakeville	Aug NQC	Market
POTTER_7_VECINO				0.02		Eagle Rock, Fulton, Lakeville	Not modeled Aug NQC	QF/Selfgen
SANTFG_7_UNITS	31400	SANTA FE	13.8	30.00	1	Lakeville		Market
SANTFG_7_UNITS	31400	SANTA FE	13.8	30.00	2	Lakeville		Market
SMUDGO_7_UNIT 1	31430	SMUDGEO1	13.8	37.00	1	Lakeville		Market
SNMALF_6_UNITS	31446	SONMA LF	9.1	5.15	1	Fulton, Lakeville	Aug NQC	QF/Selfgen
UKIAH_7_LAKEMN				1.70		Eagle Rock, Fulton, Lakeville	Not modeled	MUNI
WDFRDF_2_UNITS	31404	WEST FOR	13.8	12.51	1	Fulton, Lakeville		Market
WDFRDF_2_UNITS	31404	WEST FOR	13.8	12.49	2	Fulton, Lakeville		Market

Major new projects modeled: None

Critical Contingency Analysis Summary

Eagle Rock Sub-area

The most critical overlapping contingency is the outage of the Cortina-Mendocino 115 kV line overlapping with an outage of the Fulton-Lakeville 230 kV line. The sub-area area limitation is thermal overloading of the Eagle Rock-Cortina 115 kV line. This limiting contingency establishes a LCR of 207 MW in 2012 (includes 1 MW of QF/MUNI generation) as the minimum capacity necessary for reliable load serving capability within this sub-area.

The most critical single contingency is the outage of the Cortina-Mendocino 115 kV line. The sub-area area limitation is thermal overloading of the Eagle Rock-Cortina 115 kV line. This limiting contingency establishes a LCR of 166 MW in 2012 (includes 1 MW of QF/MUNI generation).

Effectiveness factors:

All the units within the Eagle-Rock sub-area have the same effectiveness to the described constraints. Units outside this area are not effective.

Fulton Sub-area

The most critical overlapping contingency is the outage of the Lakeville-Fulton 230 kV line #1 and the Fulton-Ignacio 230 kV line #1. The sub-area area limitation is thermal overloading of Santa Rosa-Corona 115 kV line #1. This limiting contingency establishes a LCR of 293 MW (includes 16 MW of QF and 54 MW of Muni generation) as the minimum capacity necessary for reliable load serving capability within this sub-area. All of the resources needed to meet the Eagle Rock sub-area count towards the Fulton sub-area LCR need.

Effectiveness factors:

The following table has units that are at least 5% effective to the above-mentioned constraint.

Gen Bus	Gen Name	Gen ID	Eff Fctr (%)
31404	WEST FOR	2	73
31402	BEAR CAN	1	73
31402	BEAR CAN	2	73
31404	WEST FOR	1	73
31414	GEYSER12	1	73
31418	GEYSER14	1	73
31420	GEYSER16	1	73
31422	GEYSER17	1	73
38110	NCPA2GY1	1	73
38112	NCPA2GY2	1	73
31421	BOTTLERK	1	72
31406	GEYSR5-6	1	38
31406	GEYSR5-6	2	38
31408	GEYSER78	1	38
31408	GEYSER78	2	38
31412	GEYSER11	1	38
31435	GEO.ENGY	1	38
31435	GEO.ENGY	2	38

Lakeville Sub-area

The most limiting contingency is the outage of Vaca Dixon-Tulucay 230 kV line with DEC power plant out of service. The sub-area limitation is thermal overloading of the Vaca Dixon-Lakeville 230 kV. This limiting contingency establishes a LCR of 613 MW (includes 18 MW of QF and 113 MW of MUNI generation) as the minimum capacity necessary for reliable load serving capability within this sub-area. The LCR resources needed for Eagle Rock and Fulton sub-areas can be counted toward fulfilling the requirement of Lakeville sub-area.

Effectiveness factors:

The following table has units within the North Coast/North Bay area at least 5% effective to the above-mentioned constraint.

Gen Bus	Gen Name	Gen ID	Eff Fctr (%)
31400	SANTA FE	2	37
31430	SMUDGEO1	1	37
31400	SANTA FE	1	37
31416	GEYSER13	1	37
31424	GEYSER18	1	37

31426	GEYSER20	1	37
38106	NCPA1GY1	1	37
38108	NCPA1GY2	1	37
31421	BOTTLERK	1	35
31404	WEST FOR	2	35
31402	BEAR CAN	1	35
31402	BEAR CAN	2	35
31404	WEST FOR	1	35
31414	GEYSER12	1	35
31418	GEYSER14	1	35
31420	GEYSER16	1	35
31422	GEYSER17	1	35
38110	NCPA2GY1	1	35
38112	NCPA2GY2	1	35
31406	GEYSR5-6	1	19
31406	GEYSR5-6	2	19
31408	GEYSER78	1	19
31408	GEYSER78	2	19
31412	GEYSER11	1	19
31435	GEO.ENGY	1	19
31435	GEO.ENGY	2	19

Changes compared to last year's results:

Overall the load forecast went down by 154 MW for 2012 compared with last year load forecast for 2011 and the LCR need went down by 121 MW.

North Coast/North Bay Overall Requirements:

2012	QF/Selfgen (MW)	Muni (MW)	Market (MW)	Max. Qualifying Capacity (MW)
Available generation	18	113	728	859

2012	Existing Generation Capacity Needed (MW)	Deficiency (MW)	Total MW LCR Need
Category B (Single)[11]	613	0	613
Category C (Multiple)[12]	613	0	613

[11] A single contingency means that the system will be able the survive the loss of a single element, however the operators will not have any means (other then load drop) in order to bring the system within a safe operating zone and get prepared for the next contingency as required by MORC.

[12] Multiple contingencies means that the system will be able the survive the loss of a single element, and the operators will have enough generation (other operating procedures) in order to bring the system within a safe operating zone and get prepared for the next contingency as required by MORC.

3. Sierra Area

Area Definition

The transmission tie lines into the Sierra Area are:

1) Table Mountain-Rio Oso 230 kV line
2) Table Mountain-Palermo 230 kV line
3) Table Mt-Pease 60 kV line
4) Caribou-Palermo 115 kV line
5) Drum-Summit 115 kV line #1
6) Drum-Summit 115 kV line #2
7) Spaulding-Summit 60 kV line
8) Brighton-Bellota 230 kV line
9) Rio Oso-Lockeford 230 kV line
10) Gold Hill-Eight Mile Road 230 kV line
11) Lodi STIG-Eight Mile Road 230 kV line
12) Gold Hill-Lake 230 kV line

The substations that delineate the Sierra Area are:

1) Table Mountain is out Rio Oso is in
2) Table Mountain is out Palermo is in
3) Table Mt is out Pease is in
4) Caribou is out Palermo is in
5) Drum is in Summit is out
6) Drum is in Summit is out
7) Spaulding is in Summit is out
8) Brighton is in Bellota is out
9) Rio Oso is in Lockeford is out
10) Gold Hill is in Eight Mile is out
11) Lodi STIG is in Eight Mile Road is out
12) Gold Hill is in Lake is out

Total 2012 busload within the defined area: 1713 MW with 103 MW of losses resulting in total load + losses of 1816 MW.

Total units and qualifying capacity available in this area:

MKT/SCHED RESOURCE ID	BUS #	BUS NAME	kV	NQC	UNIT ID	LCR SUB-AREA NAME	NQC Comments	CAISO Tag
BELDEN_7_UNIT 1	31784	BELDEN	13.8	115.00	1	South of Palermo, South of Table Mountain	Aug NQC	Market
BIOMAS_1_UNIT 1	32156	WOODLAND	9.1	21.64	1	Drum-Rio Oso, South of Palermo, South of Table Mountain	Aug NQC	QF/Selfgen
BNNIEN_7_ALTAPH	32376	BONNIE N	60	0.63		Placer, Drum-Rio Oso, South of Rio Oso, South of Palermo, South of Table Mountain	Not modeled Aug NQC	Market
BOGUE_1_UNITA1	32451	FREC	13.8	45.00	1	Bogue, Drum-Rio Oso, South of Table Mountain	Aug NQC	Market
BOWMN_6_UNIT	32480	BOWMAN	9.1	2.41	1	Drum-Rio Oso, South of Palermo, South of Table Mountain	Aug NQC	MUNI
BUCKCK_7_OAKFLT				1.06		South of Palermo, South of Table Mountain	Not modeled Aug NQC	Market
BUCKCK_7_PL1X2	31820	BCKS CRK	11	29.00	1	South of Palermo, South of Table Mountain	Aug NQC	Market
BUCKCK_7_PL1X2	31820	BCKS CRK	11	29.00	2	South of Palermo, South of Table Mountain	Aug NQC	Market
CHICPK_7_UNIT 1	32462	CHI.PARK	11.5	38.00	1	Placer, Drum-Rio Oso, South of Rio Oso, South of Palermo, South of Table Mountain	Aug NQC	MUNI

COLGAT_7_UNIT 1	32450	COLGATE1	13.8	161.65	1	South of Table Mountain	Aug NQC	MUNI
COLGAT_7_UNIT 2	32452	COLGATE2	13.8	161.68	1	South of Table Mountain	Aug NQC	MUNI
CRESTA_7_PL1X2	31812	CRESTA	11.5	35.00	1	South of Palermo, South of Table Mountain	Aug NQC	Market
CRESTA_7_PL1X2	31812	CRESTA	11.5	35.00	2	South of Palermo, South of Table Mountain	Aug NQC	Market
DAVIS_7_MNMETH				2.11		Drum-Rio Oso, South of Palermo, South of Table Mountain	Not modeled Aug NQC	Market
DEADCK_1_UNIT	31862	DEADWOOD	9.1	0.00	1	Drum-Rio Oso, South of Table Mountain	Aug NQC	MUNI
DEERCR_6_UNIT 1	32474	DEER CRK	9.1	3.78	1	Drum-Rio Oso, South of Palermo, South of Table Mountain	Aug NQC	Market
DRUM_7_PL1X2	32504	DRUM 1-2	6.6	13.00	1	Drum-Rio Oso, South of Palermo, South of Table Mountain	Aug NQC	Market
DRUM_7_PL1X2	32504	DRUM 1-2	6.6	13.00	2	Drum-Rio Oso, South of Palermo, South of Table Mountain	Aug NQC	Market
DRUM_7_PL3X4	32506	DRUM 3-4	6.6	13.70	1	Drum-Rio Oso, South of Palermo, South of Table Mountain	Aug NQC	Market
DRUM_7_PL3X4	32506	DRUM 3-4	6.6	13.70	2	Drum-Rio Oso, South of Palermo,	Aug NQC	Market

						South of Table Mountain		
DRUM_7_UNIT 5	32454	DRUM 5	13.8	49.50	1	Drum-Rio Oso, South of Palermo, South of Table Mountain	Aug NQC	Market
DUTCH1_7_UNIT 1	32464	DTCHFLT1	11	22.00	1	Placer, Drum-Rio Oso, South of Rio Oso, South of Palermo, South of Table Mountain	Aug NQC	Market
DUTCH2_7_UNIT 1	32502	DTCHFLT2	6.9	26.00	1	Drum-Rio Oso, South of Palermo, South of Table Mountain	Aug NQC	MUNI
ELDORO_7_UNIT 1	32513	ELDRADO1	21.6	11.00	1	Placerville, South of Rio Oso, South of Palermo, South of Table Mountain		Market
ELDORO_7_UNIT 2	32514	ELDRADO2	21.6	11.00	1	Placerville, South of Rio Oso, South of Palermo, South of Table Mountain		Market
FMEADO_6_HELLHL	32486	HELLHOLE	9.1	0.36	1	South of Rio Oso, Soth of Palermo, South of Table Mountain	Aug NQC	MUNI
FMEADO_7_UNIT	32508	FRNCH MD	4.2	16.01	1	South of Rio Oso, Soth of Palermo, South of Table Mountain	Aug NQC	MUNI
FORBST_7_UNIT 1	31814	FORBSTWN	11.5	39.00	1	Drum-Rio Oso, South of Table Mountain	Aug NQC	MUNI
GOLDHL_1_QF				0.00		Placerville, South of	Not modeled	QF/Selfgen

						Rio Oso, South of Palermo, South of Table Mountain		
GRNLF1_1_UNITS	32490	GRNLEAF1	13.8	6.19	1	Bogue, Drum-Rio Oso, South of Table Mountain	Aug NQC	QF/Selfgen
GRNLF1_1_UNITS	32490	GRNLEAF1	13.8	31.65	2	Bogue, Drum-Rio Oso, South of Table Mountain	Aug NQC	QF/Selfgen
GRNLF2_1_UNIT	32492	GRNLEAF2	13.8	35.29	1	Pease, Drum-Rio Oso, South of Table Mountain	Aug NQC	QF/Selfgen
HALSEY_6_UNIT	32478	HALSEY F	9.1	6.71	1	Placer, Drum-Rio Oso, South of Rio Oso, South of Palermo, South of Table Mountain	Aug NQC	Market
HAYPRS_6_QFUNTS	32488	HAYPRES+	9.1	0.00	1	Drum-Rio Oso, South of Palermo, South of Table Mountain	Aug NQC	QF/Selfgen
HAYPRS_6_QFUNTS	32488	HAYPRES+	9.1	0.00	2	Drum-Rio Oso, South of Palermo, South of Table Mountain	Aug NQC	QF/Selfgen
HIGGNS_7_QFUNTS				0.04		Drum-Rio Oso, South of Rio Oso, South of Palermo, South of Table Mountain	Not modeled Aug NQC	QF/Selfgen
KANAKA_1_UNIT				0.00		Drum-Rio Oso, South of Table Mountain	Not modeled Aug NQC	MUNI
KELYRG_6_UNIT	31834	KELLYRDG	9.1	10.00	1	Drum-Rio Oso, South of Table	Aug NQC	MUNI

						Mountain		
MDFKRL_2_PROJCT	32456	MIDLFORK	13.8	62.18	1	South of Rio Oso, Soth of Palermo, South of Table Mountain	Aug NQC	MUNI
MDFKRL_2_PROJCT	32458	RALSTON	13.8	84.32	1	South of Rio Oso, Soth of Palermo, South of Table Mountain	Aug NQC	MUNI
MDFKRL_2_PROJCT	32456	MIDLFORK	13.8	62.18	2	South of Rio Oso, Soth of Palermo, South of Table Mountain	Aug NQC	MUNI
NAROW1_2_UNIT	32466	NARROWS1	9.1	2.98	1	Colgate, South of Table Mountain	Aug NQC	Market
NAROW2_2_UNIT	32468	NARROWS2	9.1	20.52	1	Colgate, South of Table Mountain	Aug NQC	MUNI
NWCSTL_7_UNIT 1	32460	NEWCSTLE	13.2	0.00	1	Placer, Drum-Rio Oso, South of Rio Oso, South of Palermo, South of Table Mountain	Aug NQC	Market
OROVIL_6_UNIT	31888	OROVLLE	9.1	4.71	1	Drum-Rio Oso, South of Table Mountain	Aug NQC	QF/Selfgen
OXBOW_6_DRUM	32484	OXBOW F	9.1	6.00	1	Drum-Rio Oso, South of Palermo, South of Table Mountain	Aug NQC	MUNI
PACORO_6_UNIT	31890	PO POWER	9.1	7.97	1	Drum-Rio Oso, South of Table Mountain	Aug NQC	QF/Selfgen
PACORO_6_UNIT	31890	PO POWER	9.1	7.97	2	Drum-Rio Oso, South of Table Mountain	Aug NQC	QF/Selfgen

PLACVL_1_CHILIB	32510	CHILIBAR	4.2	2.30	1	Placerville, South of Rio Oso, South of Palermo, South of Table Mountain	Aug NQC	Market
PLACVL_1_RCKCRE				0.00		Placerville, South of Rio Oso, South of Palermo, South of Table Mountain	Not modeled Aug NQC	Market
PLSNTG_7_LNCLND	32408	PLSNT GR	60	0.72		Drum-Rio Oso, South of Rio Oso, South of Palermo, South of Table Mountain	Not modeled Aug NQC	Market
POEPH_7_UNIT 1	31790	POE 1	13.8	60.00	1	South of Palermo, South of Table Mountain	Aug NQC	Market
POEPH_7_UNIT 2	31792	POE 2	13.8	60.00	1	South of Palermo, South of Table Mountain	Aug NQC	Market
RCKCRK_7_UNIT 1	31786	ROCK CK1	13.8	56.00	1	South of Palermo, South of Table Mountain	Aug NQC	Market
RCKCRK_7_UNIT 2	31788	ROCK CK2	13.8	56.00	1	South of Palermo, South of Table Mountain	Aug NQC	Market
RIOOSO_1_QF				0.94		Drum-Rio Oso, South of Palermo, South of Table Mountain	Not modeled Aug NQC	QF/Selfgen
ROLLIN_6_UNIT	32476	ROLLINSF	9.1	11.09	1	Drum-Rio Oso, South of Palermo, South of Table Mountain	Aug NQC	MUNI
SLYCRK_1_UNIT 1	31832	SLY.CR.	9.1	10.36	1	Drum-Rio Oso, South of Table	Aug NQC	MUNI

						Mountain		
SPAULD_6_UNIT 3	32472	SPAULDG	9.1	5.47	3	Drum-Rio Oso, South of Palermo, South of Table Mountain	Aug NQC	Market
SPAULD_6_UNIT12	32472	SPAULDG	9.1	4.96	1	Drum-Rio Oso, South of Palermo, South of Table Mountain	Aug NQC	Market
SPAULD_6_UNIT12	32472	SPAULDG	9.1	4.96	2	Drum-Rio Oso, South of Palermo, South of Table Mountain	Aug NQC	Market
SPI LI_2_UNIT 1	32498	SPILINCF	12.5	10.55	1	Drum-Rio Oso, South of Rio Oso, South of Palermo, South of Table Mountain	Aug NQC	QF/Selfgen
STIGCT_2_LODI	38114	Stig CC	13.8	49.50	1	South of Rio Oso, Soth of Palermo, South of Table Mountain		MUNI
ULTRCK_2_UNIT	32500	ULTR RCK	9.1	19.12	1	Drum-Rio Oso, South of Rio Oso, South of Palermo, South of Table Mountain	Aug NQC	QF/Selfgen
WDLEAF_7_UNIT 1	31794	WOODLEAF	13.8	55.00	1	Drum-Rio Oso, South of Table Mountain	Aug NQC	MUNI
WHEATL_6_LNDFIL	32350	WHEATLND	60	1.20		Colgate, South of Table Mountain	Not modeled Aug NQC	Market
WISE_1_UNIT 1	32512	WISE	12	9.84	1	Placer, Drum-Rio Oso, South of Rio Oso, South of	Aug NQC	Market

						Palermo, South of Table Mountain		
WISE_1_UNIT 2	32512	WISE	12	0.22	1	Placer, Drum-Rio Oso, South of Rio Oso, South of Palermo, South of Table Mountain	Aug NQC	Market
YUBACT_1_SUNSWT	32494	YUBA CTY	9.1	26.26	1	Pease, Drum-Rio Oso, South of Table Mountain	Aug NQC	QF/Selfgen
YUBACT_6_UNITA1	32496	YCEC	13.8	46.00	1	Pease, Drum-Rio Oso, South of Table Mountain		Market
CAMPFW_7_FARWST	32470	CMP.FARW	9.1	4.60	1	Colgate, South of Table Mountain	No NQC - hist. data	MUNI
NA	32162	RIV.DLTA	9.11	0.00	1	Drum-Rio Oso, South of Palermo, South of Table Mountain	No NQC - hist. data	QF/Selfgen
UCDAVS_1_UNIT	32166	UC DAVIS	9.1	3.50	1	Drum-Rio Oso, South of Palermo, South of Table Mountain	No NQC - hist. data	QF/Selfgen
New unit	38123	Q267CT1	18	166.00	1	South of Rio Oso, Soth of Palermo, South of Table Mountain	No NQC - Pmax	MUNI
New unit	38124	Q267ST1	18	114.00	1	South of Rio Oso, Soth of Palermo, South of Table Mountain	No NQC - Pmax	MUNI

Major new projects modeled:

1. Table Mountain-Rio Oso Reconductor and Tower Upgrade
2. Atlantic-Lincoln 115 kV Transmission Upgrade

3. Gold Hill – Horseshoe 115 kV line Reconductoring
4. Palermo-Rio Oso 115 kV Reconductoring
5. Lodi Energy Center

Critical Contingency Analysis Summary

South of Table Mountain Sub-area

The most critical contingency is the loss of the Table Mountain-Rio Oso 230 kV and Table Mountain-Palermo double circuit tower line outage. The area limitation is thermal overloading of the Caribou-Palermo 115 kV line. This limiting contingency establishes in 2012 a LCR of 1399 MW (includes 176 MW of QF and 1101 MW of Muni generation) as the minimum capacity necessary for reliable load serving capability within this area.

The units required for the South of Palermo sub-area satisfy the category B requirement for this sub-area.

Effectiveness factors:

The following table has all units in Sierra area and their effectiveness factor to the above-mentioned constraint.

Gen Bus	Gen Name	Gen ID	Eff Fctr. (%)
31814	FORBSTWN	1	8
31794	WOODLEAF	1	8
31832	SLY.CR.	1	7
31862	DEADWOOD	1	7
31888	OROVLLE	1	6
31890	PO POWER	2	6
31890	PO POWER	1	6
31834	KELLYRDG	1	6
32452	COLGATE2	1	5
32450	COLGATE1	1	5
32466	NARROWS1	1	5
32468	NARROWS2	1	5
32470	CMP.FARW	1	5
32451	FREC	1	5
32490	GRNLEAF1	2	4
32490	GRNLEAF1	1	4
32496	YCEC	1	3
32494	YUBA CTY	1	3

32492	GRNLEAF2	1	3
32156	WOODLAND	1	3
31820	BCKS CRK	1	2
31820	BCKS CRK	2	2
31788	ROCK CK2	1	2
31812	CRESTA	1	2
31812	CRESTA	2	2
31792	POE 2	1	2
31790	POE 1	1	2
31786	ROCK CK1	1	2
31784	BELDEN	1	2
32166	UC DAVIS	1	2
32500	ULTR RCK	1	2
32498	SPILINCF	1	2
32162	RIV.DLTA	1	2
32510	CHILIBAR	1	2
32514	ELDRADO2	1	2
32513	ELDRADO1	1	2
32478	HALSEY F	1	2
32458	RALSTON	1	2
32456	MIDLFORK	1	2
32456	MIDLFORK	2	2
38114	Stig CC	1	2
32460	NEWCSTLE	1	2
32512	WISE	1	2
32486	HELLHOLE	1	2
32508	FRNCH MD	1	2
32502	DTCHFLT2	1	2
32462	CHI.PARK	1	2
32464	DTCHFLT1	1	1
32454	DRUM 5	1	1
32476	ROLLINSF	1	1
32484	OXBOW F	1	1
32474	DEER CRK	1	1
32506	DRUM 3-4	1	1
32506	DRUM 3-4	2	1
32504	DRUM 1-2	1	1
32504	DRUM 1-2	2	1
32488	HAYPRES+	1	1
32488	HAYPRES+	2	1
32480	BOWMAN	1	1
32472	SPAULDG	1	1
32472	SPAULDG	2	1
32472	SPAULDG	3	1
38123	Q267CT1	1	1
38124	Q267ST1	1	1

Colgate Sub-area

No requirements due to the addition of the Atlantic-Lincoln 115 kV transmission upgrade project. If this project is delayed all units within this area (Narrows #1 & #2 and Camp Far West) are needed.

Pease Sub-area

The most critical contingency is the loss of the Palermo-East Nicolaus 115 kV line with Green Leaf II Cogen unit out of service. The area limitation is thermal overloading of the Palermo-Pease 115 kV line. This limiting contingency establishes a LCR of 103 MW (includes 62 MW of QF generation) in 2012 as the minimum capacity necessary for reliable load serving capability within this sub-area.

Effectiveness factors:

All units within this area (Greenleaf #2, Yuba City and Yuba City EC) have the same effectiveness factor.

Bogue Sub-area

No requirement due to the Palermo-Rio Oso Reconductoring Project. If this project is delayed all units within this area (Greenleaf #1 units 1&2 and Feather River EC) are needed.

South of Palermo Sub-area

The most critical contingency is the loss of the Double Circuit Tower Line Table Mountain-Rio Oso and Colgate-Rio Oso 230 kV lines. The area limitation is thermal overloading of the Pease-Rio Oso 115 kV line. This limiting contingency establishes a LCR of 1626 MW (includes 694 MW of QF and Muni generation as well as 268 MW of deficiency) in 2012 as the minimum capacity necessary for reliable load serving capability within this sub-area.

The most critical single contingency is the loss of the Palermo- East Nicolaus 115 kV line with Belden unit out of service. The area limitation is thermal overloading of the Pease-Rio Oso 115 kV line. This contingency establishes in 2012 a LCR of 1394 MW (includes 694 MW of QF and Muni generation as well as 36 MW of deficiency).

Effectiveness factors:

All units within the South of Palermo are needed therefore no effectiveness factor is required.

Placerville Sub-area

The most critical contingency is the loss of the Gold Hill-Clarksville 115 kV line followed by loss of the Gold Hill-Missouri Flat #2 115 kV line. The area limitation is thermal overloading of the Gold Hill-Missouri Flat #1 115 kV line. This limiting contingency establishes a LCR of 81 MW (includes 0 MW of QF and Muni generation as well as 57 MW of deficiency) in 2012 as the minimum capacity necessary for reliable load serving capability within this sub-area.

Effectiveness factors:

All units within this area (El Dorado units 1&2 and Chili Bar) are needed therefore no effectiveness factor is required.

Placer Sub-area

The most critical contingency is the loss of the Gold Hill-Placer #1 115 kV line followed by loss of the Gold Hill-Placer #2 115 kV line. The area limitation is thermal overloading of the Drum-Higgins 115 kV line. This limiting contingency establishes a LCR of 75 MW (includes 0 MW of QF and Muni generation) in 2012 as the minimum capacity necessary for reliable load serving capability within this sub-area.

The single most critical contingency is the loss of the Gold Hill-Placer #2 115 kV line with Chicago Park unit out of service. The area limitation is thermal overloading of the Drum-Higgins 115 kV line. This limiting contingency establishes a local capacity need of 44 MW (includes 0 MW of QF and Muni generation) in 2012 as the minimum capacity necessary for reliable load serving capability within this sub-area.

Effectiveness factors:

All units within this area (Chicago Park, Dutch Flat#1, Wise units 1&2, Newcastle and Halsey) have the same effectiveness factor.

Drum-Rio Oso Sub-area

The most critical contingency is the loss of the Rio Oso #2 230/115 transformer followed by loss of the Rio Oso-Brighton 230 kV line. The area limitation is thermal overloading of the Rio Oso #1 230/115 kV transformer. This limiting contingency establishes in 2012 a LCR of 625 MW (includes 374 MW of QF and Muni generation) as the minimum capacity necessary for reliable load serving capability within this sub-area.

The single most critical contingency is the loss of the Rio Oso #2 230/115 transformer. The area limitation is thermal overloading of the Rio Oso #1 230/115 kV transformer. This limiting contingency establishes in 2012 a LCR of 254 MW (includes 374 MW of QF and Muni generation).

Effectiveness factors:

The following table has all units in Drum-Rio Oso sub-area and their effectiveness factor to the above-mentioned constraint.

Gen Bus	Gen Name	Gen ID	Eff Fctr. (%)
32156	WOODLAND	1	22
32490	GRNLEAF1	1	22
32490	GRNLEAF1	2	22
32451	FREC	1	21
32166	UC DAVIS	1	18
32498	SPILINCF	1	15
32502	DTCHFLT2	1	15
32494	YUBA CTY	1	14
32496	YCEC	1	14
32492	GRNLEAF2	1	13
32454	DRUM 5	1	13
32476	ROLLINSF	1	13
32474	DEER CRK	1	13
32504	DRUM 1-2	1	13
32504	DRUM 1-2	2	13
32506	DRUM 3-4	1	13
32506	DRUM 3-4	2	13
32484	OXBOW F	1	13
32472	SPAULDG	3	12

32472	SPAULDG	1	12
32472	SPAULDG	2	12
32488	HAYPRES+	1	12
32480	BOWMAN	1	12
32488	HAYPRES+	2	12
32464	DTCHFLT1	1	11
32162	RIV.DLTA	1	11
32462	CHI.PARK	1	9
32500	ULTR RCK	1	6
31862	DEADWOOD	1	5
31814	FORBSTWN	1	5
31832	SLY.CR.	1	5
31794	WOODLEAF	1	5
32478	HALSEY F	1	2
31888	OROVLLE	1	2
32512	WISE	1	2
31834	KELLYRDG	1	2
31890	PO POWER	1	2
31890	PO POWER	2	2
32460	NEWCSTLE	1	1

South of Rio Oso Sub-area

The most critical contingency is the loss of the Rio Oso-Gold Hill 230 line followed by loss of the Rio Oso-Lincoln 115 kV line or vice versa. The area limitation is thermal overloading of the Rio Oso-Atlantic 230 kV line. This limiting contingency establishes a LCR of 630 MW (includes 622 MW of QF and Muni) in 2012 as the minimum capacity necessary for reliable load serving capability within this sub-area.

The single most critical contingency is the loss of the Rio Oso-Gold Hill 230 line with the Ralston unit out of service. The area limitation is thermal overloading of the Rio Oso-Atlantic 230 kV line. This limiting contingency establishes a LCR of 453 MW (includes 622 MW of QF and Muni generation) in 2012.

Effectiveness factors:

The following table has all units in South of Rio Oso sub-area and their effectiveness factor to the above-mentioned constraint.

Gen Bus	Gen Name	Gen ID	Eff Fctr. (%)
32498	SPILINCF	1	49
32500	ULTR RCK	1	49
32456	MIDLFORK	1	33

32456	MIDLFORK	2	33
32458	RALSTON	1	33
32513	ELDRADO1	1	32
32514	ELDRADO2	1	32
32510	CHILIBAR	1	32
32486	HELLHOLE	1	31
32508	FRNCH MD	1	30
32460	NEWCSTLE	1	26
32478	HALSEY F	1	24
32512	WISE	1	24
38114	Stig CC	1	14
38123	Q267CT	1	14
38124	Q267ST	1	14
32462	CHI.PARK	1	8
32464	DTCHFLT1	1	4

Changes compared to last year's results:

Overall the Sierra Area load forecast went down by 161 MW. Along with a few new transmission projects there is also one new power plant (Lodi Energy Center) modeled within the Sierra LCR area. As a result, the existing generation capacity needed is increased by 175 MW. As such, the magnitude of the deficiency has significantly reduced because of this resource addition.

Sierra Overall Requirements:

2012	QF (MW)	Muni (MW)	Market (MW)	Max. Qualifying Capacity (MW)
Available generation	176	1101	760	2037

2012	Existing Generation Capacity Needed (MW)	Deficiency (MW)	Total MW LCR Need
Category B (Single)[13]	1489	36	1525
Category C (Multiple)[14]	1685	289	1974

[13] A single contingency means that the system will be able the survive the loss of a single element, however the operators will not have any means (other then load drop) in order to bring the system within a safe operating zone and get prepared for the next contingency as required by MORC.

[14] Multiple contingencies means that the system will be able the survive the loss of a single element, and the operators will have enough generation (other operating procedures) in order to bring the system within a safe operating zone and get prepared for the next contingency as required by MORC.

4. Stockton Area

Area Definition

The transmission facilities that establish the boundary of the Tesla-Bellota Sub-area are:

1) Bellota 230/115 kV Transformer #1
2) Bellota 230/115 kV Transformer #2
3) Tesla-Tracy 115 kV Line
4) Tesla-Salado 115 kV Line
5) Tesla-Salado-Manteca 115 kV line
6) Tesla-Schulte 115 kV Line
7) Tesla-Kasson-Manteca 115 kV Line

The substations that delineate the Tesla-Bellota Sub-area are:

1) Bellota 230 kV is out Bellota 115 kV is in
2) Bellota 230 kV is out Bellota 115 kV is in
3) Tesla is out Tracy is in
4) Tesla is out Salado is in
5) Tesla is out Salado and Manteca are in
6) Tesla is out Schulte is in
7) Tesla is out Kasson and Manteca are in

The transmission facilities that establish the boundary of the Lockeford Sub-area are:

1) Lockeford-Industrial 60 kV line
2) Lockeford-Lodi #1 60 kV line
3) Lockeford-Lodi #2 60 kV line
4) Lockeford-Lodi #3 60 kV line

The substations that delineate the Lockeford Sub-area are:

1) Lockeford is out Industrial is in
2) Lockeford is out Lodi is in
3) Lockeford is out Lodi is in
4) Lockeford is out Lodi is in

The transmission facilities that establish the boundary of the Weber Sub-area are:

1) Weber 230/60 kV Transformer #1
2) Weber 230/60 kV Transformer #2

3) Weber 230/60 kV Transformer #2a

The substations that delineate the Weber Sub-area are:

1) Weber 230 kV is out Weber 60 kV is in
2) Weber 230 kV is out Weber 60 kV is in
3) Weber 230 kV is out Weber 60 kV is in

Total 2011 busload within the defined area: 1067 MW with 19 MW of losses resulting in total load + losses of 1086 MW.

Total units and qualifying capacity available in this area:

MKT/SCHED RESOURCE ID	BUS #	BUS NAME	kV	NQC	UNIT ID	LCR SUB-AREA NAME	NQC Comments	CAISO Tag
BEARDS_7_UNIT 1	34074	BEARDSLY	6.9	8.36	1	Tesla-Bellota	Aug NQC	MUNI
COGNAT_1_UNIT	33818	COG.NTNL	12	25.46	1	Weber	Aug NQC	QF/Selfgen
CURIS_1_QF				0.49		Tesla-Bellota	Not modeled Aug NQC	QF/Selfgen
DONNLS_7_UNIT	34058	DONNELLS	13.8	72.00	1	Tesla-Bellota	Aug NQC	MUNI
LODI25_2_UNIT 1	38120	LODI25CT	9.11	22.70	1	Lockeford		MUNI
PHOENX_1_UNIT				1.46		Tesla-Bellota	Not modeled Aug NQC	Market
SCHLTE_1_UNITA1	33805	GWFTRCY1	13.8	83.56	1	Tesla-Bellota		Market
SCHLTE_1_UNITA2	33807	GWFTRCY2	13.8	82.88	1	Tesla-Bellota		Market
SNDBAR_7_UNIT 1	34060	SANDBAR	13.8	10.67	1	Tesla-Bellota	Aug NQC	MUNI
SPIFBD_1_PL1X2	33917	FBERBORD	115	2.28	1	Tesla-Bellota	Aug NQC	QF/Selfgen
SPRGAP_1_UNIT 1	34078	SPRNG GP	6	0.02	1	Tesla-Bellota	Aug NQC	Market
STANIS_7_UNIT 1	34062	STANISLS	13.8	91.00	1	Tesla-Bellota	Aug NQC	Market
STNRES_1_UNIT	34056	STNSLSRP	13.8	15.72	1	Tesla-Bellota	Aug NQC	QF/Selfgen
STOKCG_1_UNIT 1	33814	CPC STCN	12.5	42.74	1	Tesla-Bellota	Aug NQC	QF/Selfgen
TULLCK_7_UNITS	34076	TULLOCH	6.9	8.23	1	Tesla-Bellota	Aug NQC	MUNI
TULLCK_7_UNITS	34076	TULLOCH	6.9	8.24	2	Tesla-Bellota	Aug NQC	MUNI
ULTPCH_1_UNIT 1	34050	CH.STN.	13.8	13.34	1	Tesla-Bellota	Aug NQC	QF/Selfgen
VLYHOM_7_SSJID				1.39		Tesla-Bellota	Not modeled Aug NQC	QF/Selfgen
CAMCHE_1_PL1X3	33850	CAMANCHE	4.2	3.50	1	Tesla-Bellota	No NQC - hist. data	MUNI

CAMCHE_1_PL1X3	33850	CAMANCHE	4.2	3.50	2	Tesla-Bellota	No NQC - hist. data	MUNI
CAMCHE_1_PL1X3	33850	CAMANCHE	4.2	3.50	3	Tesla-Bellota	No NQC - hist. data	MUNI
NA	33687	STKTN WW	60	1.50	1	Weber	No NQC - hist. data	QF/Selfgen
NA	33830	GEN.MILL	9.11	2.50	1	Lockeford	No NQC - hist. data	QF/Selfgen

Major new projects modeled:

1. Tesla 115 kV Capacity Increase
2. Tesla-Schulte, Lammer-Kasson & Schulte-Lammers Tower Raise Project
3. Weber-Stockton “A” #1 & #2 60 kV Reconductoring

<u>Critical Contingency Analysis Summary</u>

Stockton overall

The requirement for this area is driven by the sum of requirements for the Tesla-Bellota, Lockeford, Stagg and Weber Sub-areas.

Tesla-Bellota Sub-area

The two most critical contingencies listed below together establish a local capacity need of 451 MW (includes 76 MW of QF and 118 MW of Muni generation as well as 114 MW of deficiency) in 2012 as the minimum capacity necessary for reliable load serving capability within this sub-area.

The most critical contingency for the Tesla-Bellota pocket is the loss of Tesla-Tracy 115 kV and Schulte-Lammers 115 kV. The area limitation is thermal overload of the Tesla-Kasson-Manteca 115 kV line above its emergency rating. This limiting contingency establishes a local capacity need of 401 MW (includes 76 MW of QF and 118 MW of Muni generation as well as 114 MW of deficiency) in 2012.

The second most critical contingency for the Tesla-Bellota pocket is the loss of Tesla-Tracy 115 kV and Tesla-Kasson-Manteca 115 kV. The area limitation is thermal overload of the Tesla-Schulte 115 kV line. This limiting contingency establishes a 2012 local capacity need of 337 MW (includes 76 MW of QF and 118 MW of Muni generation).

The single most critical contingency for the Tesla-Bellota pocket is the loss of Tesla-Tracy 115 kV line and the loss of the Stanislaus unit #1. The area limitation is thermal overload of the Tesla-Schulte 115 kV line. This single contingency establishes a local capacity need of 123 MW (includes 194 MW of QF and Muni generation) in 2012.

Effectiveness factors:

All units within this sub-area are needed for the most limiting contingencies therefore no effectiveness factor is required.

Lockeford Sub-area

The critical contingency for the Lockeford area is the loss of Lockeford-Industrial 60 kV circuit and Lockeford-Lodi #2 60 kV circuit. The area limitation is thermal overloading of the Lockeford-Lodi Jct. section of the Lockeford-Lodi #3 60 kV circuit. This limiting contingency establishes a 2012 local capacity need of 55 MW (including 2 MW of QF and 23 MW of Muni generation as well as 30 MW of deficiency) as the minimum capacity necessary for reliable load serving capability within this area.

Effectiveness factors:

All units within this sub-area are needed therefore no effectiveness factor is required.

Weber Sub-area

The critical contingency for the Weber area is the loss of the Weber 230/60 kV Transformer #1 with the Cogeneration National out of service. The area limitation is thermal overloading of the remaining Weber 230/60 kV Transformers #2 & #2a. This limiting contingency establishes a local capacity need of 61 MW (including 27 MW of QF and Muni generation as well as a deficiency of 34 MW) in 2012 as the minimum capacity necessary for reliable load serving capability within this sub-area.

The single most critical contingency for this sub-area is the loss of Weber 230/60 kV Transformer #1. The area limitation is thermal overloading of the remaining Weber 230/60 kV Transformers #2 & #2a. This limiting contingency establishes a local capacity need of 22 MW (including 27 MW of QF and Muni generation) in 2012.

Effectiveness factors:

All units within this sub-area are needed therefore no effectiveness factor is required.

Changes compared to last year's results:

Overall the Stockton area load forecast went down by 77 MW. There are also two new transmission upgrades (Tesla-Schulte, Lammer-Kasson & Schulte-Lammers Tower Raise Project & Weber-Stockton "A" #1 & #2 60 kV Reconductoring) modeled in the Stockton LCR area this year. As a result, the overall requirement for the Stockton area went down by 126 MW.

Stockton Overall Requirements:

2012	QF (MW)	Muni (MW)	Market (MW)	Max. Qualifying Capacity (MW)
Available generation	105	141	259	505

2012	Existing Generation Capacity Needed (MW)	Deficiency (MW)	Total MW LCR Need
Category B (Single)[15]	145	0	145
Category C (Multiple)[16]	389	178	567

5. Greater Bay Area

<u>Area Definition</u>

The transmission tie lines into the Greater Bay Area are:

1) Lakeville-Sobrante 230 kV
2) Ignacio-Sobrante 230 kV
3) Parkway-Moraga 230 kV
4) Bahia-Moraga 230 kV

[15] A single contingency means that the system will be able the survive the loss of a single element, however the operators will not have any means (other then load drop) in order to bring the system within a safe operating zone and get prepared for the next contingency as required by MORC.

[16] Multiple contingencies means that the system will be able the survive the loss of a single element, and the operators will have enough generation (other operating procedures) in order to bring the system within a safe operating zone and get prepared for the next contingency as required by MORC.

5) Lambie SW Sta-Vaca Dixon 230 kV
6) Peabody-Birds Landing SW Sta 230 kV
7) Tesla-Kelso 230 kV
8) Tesla-Delta Switching Yard 230 kV
9) Tesla-Pittsburg #1 230 kV
10) Tesla-Pittsburg #2 230 kV
11) Tesla-Newark #1 230 kV
12) Tesla-Newark #2 230 kV
13) Tesla-Ravenswood 230 kV
14) Tesla-Metcalf 500 kV
15) Moss Landing-Metcalf 500 kV
16) Moss Landing-Metcalf #1 230 kV
17) Moss Landing-Metcalf #2 230 kV
18) Oakdale TID-Newark #1 115 kV
19) Oakdale TID-Newark #2 115 kV

The substations that delineate the Greater Bay Area are:

1) Lakeville is out Sobrante is in
2) Ignacio is out Crocket and Sobrante are in
3) Parkway is out Moraga is in
4) Bahia is out Moraga is in
5) Lambie SW Sta is in Vaca Dixon is out
6) Peabody is out Birds Landing SW Sta is in
7) Tesla and USWP Ralph are out Kelso is in
8) Tesla and Altmont Midway are out Delta Switching Yard is in
9) Tesla and Tres Vaqueros are out Pittsburg is in
10) Tesla and Flowind are out Pittsburg is in
11) Tesla is out Newark is in
12) Tesla is out Newark and Patterson Pass are in
13) Tesla is out Ravenswood is in
14) Tesla is out Metcalf is in
15) Moss Landing is out Metcalf is in
16) Moss Landing is out Metcalf is in
17) Moss Landing is out Metcalf is in
18) Oakdale TID is out Newark is in
19) Oakdale TID is out Newark is in

Total 2012 bus load within the defined area is 9493 MW with 197 MW of losses and 264 MW of pumps resulting in total load + losses + pumps of 9954 MW. This corresponds to about 9355 MW of load per CEC forecast since there are about 600 MW of loads behind the meter modeled in the base cases.

Total units and qualifying capacity available in this area:

MKT/SCHED RESOURCE ID	BUS #	BUS NAME	kV	NQC	UNIT ID	LCR SUB-AREA NAME	NQC Comments	CAISO Tag
ALMEGT_1_UNIT 1	38118	ALMDACT1	13.8	23.80	1	Oakland		MUNI
ALMEGT_1_UNIT 2	38119	ALMDACT2	13.8	24.40	1	Oakland		MUNI
BANKPP_2_NSPIN	38820	DELTA A	13.2	9.00	1	Contra Costa	Pumps	MUNI
BANKPP_2_NSPIN	38820	DELTA A	13.2	9.00	2	Contra Costa	Pumps	MUNI
BANKPP_2_NSPIN	38820	DELTA A	13.2	22.00	3	Contra Costa	Pumps	MUNI
BANKPP_2_NSPIN	38815	DELTA B	13.2	28.00	4	Contra Costa	Pumps	MUNI
BANKPP_2_NSPIN	38815	DELTA B	13.2	28.00	5	Contra Costa	Pumps	MUNI
BANKPP_2_NSPIN	38770	DELTA C	13.2	28.00	6	Contra Costa	Pumps	MUNI
BANKPP_2_NSPIN	38770	DELTA C	13.2	28.00	7	Contra Costa	Pumps	MUNI
BANKPP_2_NSPIN	38765	DELTA D	13.2	28.00	8	Contra Costa	Pumps	MUNI
BANKPP_2_NSPIN	38765	DELTA D	13.2	28.00	9	Contra Costa	Pumps	MUNI
BANKPP_2_NSPIN	38760	DELTA E	13.2	28.00	10	Contra Costa	Pumps	MUNI
BANKPP_2_NSPIN	38760	DELTA E	13.2	28.00	11	Contra Costa	Pumps	MUNI
BLHVN_7_MENLOP				1.16		None	Not modeled Aug NQC	QF/Selfgen
BRDSLD_2_HIWIND	32172	HIGHWINDS	34.5	34.53	1	Contra Costa	Aug NQC	Wind
BRDSLD_2_SHILO1	32176	SHILOH	34.5	37.11	1	Contra Costa	Aug NQC	Wind
BRDSLD_2_SHILO2	32177	SHILO	34.5	36.03	2	Contra Costa	Aug NQC	Wind
CALPIN_1_AGNEW	35860	OLS-AGNE	9.11	22.35	1	San Jose	Aug NQC	QF/Selfgen
CARDCG_1_UNITS	33463	CARDINAL	12.5	11.04	1	None	Aug NQC	QF/Selfgen
CARDCG_1_UNITS	33463	CARDINAL	12.5	11.04	2	None	Aug NQC	QF/Selfgen
CLRMTK_1_QF				0.00		Oakland	Not modeled	QF/Selfgen
COCOPP_7_UNIT 6	33116	C.COS 6	18	337.00	1	Contra Costa		Market
COCOPP_7_UNIT 7	33117	C.COS 7	18	337.00	1	Contra Costa		Market
CONTAN_1_UNIT	36856	CCA100	13.8	25.80	1	San Jose	Aug NQC	QF/Selfgen

CROKET_7_UNIT	32900	CRCKTCOG	18	173.57	1	Pittsburg	Aug NQC	QF/Selfgen
CSCCOG_1_UNIT 1	36854	Cogen	12	3.00	1	San Jose		MUNI
CSCCOG_1_UNIT 1	36854	Cogen	12	3.00	2	San Jose		MUNI
CSCGNR_1_UNIT 1	36858	Gia100	13.8	24.00	1	San Jose		MUNI
CSCGNR_1_UNIT 2	36895	Gia200	13.8	24.00	2	San Jose		MUNI
DELTA_2_PL1X4	33107	DEC STG1	24	269.61	1	Pittsburg	Aug NQC	Market
DELTA_2_PL1X4	33108	DEC CTG1	18	181.13	1	Pittsburg	Aug NQC	Market
DELTA_2_PL1X4	33109	DEC CTG2	18	181.13	1	Pittsburg	Aug NQC	Market
DELTA_2_PL1X4	33110	DEC CTG3	18	181.13	1	Pittsburg	Aug NQC	Market
DUANE_1_PL1X3	36863	DVRaGT1	13.8	49.27	1	San Jose		MUNI
DUANE_1_PL1X3	36864	DVRbGT2	13.8	49.27	1	San Jose		MUNI
DUANE_1_PL1X3	36865	DVRaST3	13.8	49.26	1	San Jose		MUNI
FLOWD1_6_ALTPP1	35318	FLOWDPTR	9.11	0.00	1	Contra Costa	Aug NQC	Wind
FLOWD2_2_UNIT 1	35318	FLOWDPTR	9.11	3.32	1	Contra Costa	Aug NQC	Wind
GATWAY_2_PL1X3	33118	GATEWAY1	18	189.27	1	Contra Costa	Aug NQC	Market
GATWAY_2_PL1X3	33119	GATEWAY2	18	185.36	1	Contra Costa	Aug NQC	Market
GATWAY_2_PL1X3	33120	GATEWAY3	18	185.36	1	Contra Costa	Aug NQC	Market
GILROY_1_UNIT	35850	GLRY COG	13.8	69.30	1	Llagas	Aug NQC	Market
GILROY_1_UNIT	35850	GLRY COG	13.8	35.70	2	Llagas	Aug NQC	Market
GILRPP_1_PL1X2	35851	GROYPKR1	13.8	45.50	1	Llagas	Aug NQC	Market
GILRPP_1_PL1X2	35852	GROYPKR2	13.8	45.50	1	Llagas	Aug NQC	Market
GILRPP_1_PL3X4	35853	GROYPKR3	13.8	46.00	1	Llagas	Aug NQC	Market
GRZZLY_1_BERKLY	32740	HILLSIDE	115	24.96	1	None	Aug NQC	QF/Selfgen
GWFPW1_6_UNIT	33131	GWF #1	9.11	18.01	1	Pittsburg, Contra Costa	Aug NQC	QF/Selfgen
GWFPW2_1_UNIT 1	33132	GWF #2	13.8	18.00	1	Pittsburg	Aug NQC	QF/Selfgen
GWFPW3_1_UNIT 1	33133	GWF #3	13.8	16.94	1	Pittsburg, Contra Costa	Aug NQC	QF/Selfgen
GWFPW4_6_UNIT 1	33134	GWF #4	13.8	16.77	1	Pittsburg, Contra Costa	Aug NQC	QF/Selfgen
GWFPW5_6_UNIT 1	33135	GWF #5	13.8	17.72	1	Pittsburg	Aug NQC	QF/Selfgen
HICKS_7_GUADLP				2.07		None	Not modeled Aug NQC	QF/Selfgen
KIRKER_7_KELCYN	32951	KIRKER	115	3.21		Pittsburg	Not modeled	Market
LAWRNC_7_SUNYVL				0.12		None	Not modeled Aug	Market

							NQC	
LECEF_1_UNITS	35854	LECEFGT1	13.8	46.50	1	San Jose	Aug NQC	Market
LECEF_1_UNITS	35855	LECEFGT2	13.8	46.50	1	San Jose	Aug NQC	Market
LECEF_1_UNITS	35856	LECEFGT3	13.8	46.50	1	San Jose	Aug NQC	Market
LECEF_1_UNITS	35857	LECEFGT4	13.8	46.50	1	San Jose	Aug NQC	Market
LFC 51_2_UNIT 1	35310	LFC FIN+	9.11	2.05	1	None	Aug NQC	Wind
LMBEPK_2_UNITA1	32173	LAMBGT1	13.8	47.00	1	Contra Costa	Aug NQC	Market
LMBEPK_2_UNITA2	32174	GOOSEHGT	13.8	46.00	2	Contra Costa	Aug NQC	Market
LMBEPK_2_UNITA3	32175	CREEDGT1	13.8	47.00	3	Contra Costa	Aug NQC	Market
LMEC_1_PL1X3	33111	LMECCT2	18	163.20	1	Pittsburg	Aug NQC	Market
LMEC_1_PL1X3	33112	LMECCT1	18	163.20	1	Pittsburg	Aug NQC	Market
LMEC_1_PL1X3	33113	LMECST1	18	229.60	1	Pittsburg	Aug NQC	Market
MARKHM_1_CATLST	35863	CATALYST	9.11	0.00	1	San Jose		QF/Selfgen
METCLF_1_QF				0.08		None	Not modeled Aug NQC	QF/Selfgen
METEC_2_PL1X3	35881	MEC CTG1	18	178.43	1	None	Aug NQC	Market
METEC_2_PL1X3	35882	MEC CTG2	18	178.43	1	None	Aug NQC	Market
METEC_2_PL1X3	35883	MEC STG1	18	213.14	1	None	Aug NQC	Market
MILBRA_1_QF				0.00		None	Not modeled	QF/Selfgen
MISSIX_1_QF				0.09		None	Not modeled Aug NQC	QF/Selfgen
MLPTAS_7_QFUNTS				0.01		San Jose	Not modeled Aug NQC	QF/Selfgen
MNTAGU_7_NEWBYI				3.56		None	Not modeled Aug NQC	QF/Selfgen
NEWARK_1_QF				0.02		None	Not modeled Aug NQC	QF/Selfgen
OAK C_7_UNIT 1	32901	OAKLND 1	13.8	55.00	1	Oakland		Market
OAK C_7_UNIT 2	32902	OAKLND 2	13.8	55.00	1	Oakland		Market
OAK C_7_UNIT 3	32903	OAKLND 3	13.8	55.00	1	Oakland		Market
OAK L_7_EBMUD				0.48		Oakland	Not modeled Aug NQC	MUNI
OXMTN_6_LNDFIL	33469	OX_MTN	4.16	1.45	1	None		Market
OXMTN_6_LNDFIL	33469	OX_MTN	4.16	1.45	2	None		Market
OXMTN_6_LNDFIL	33469	OX_MTN	4.16	1.45	3	None		Market

OXMTN_6_LNDFIL	33469	OX_MTN	4.16	1.45	4	None		Market
OXMTN_6_LNDFIL	33469	OX_MTN	4.16	1.45	5	None		Market
OXMTN_6_LNDFIL	33469	OX_MTN	4.16	1.45	6	None		Market
OXMTN_6_LNDFIL	33469	OX_MTN	4.16	1.45	7	None		Market
PALALT_7_COBUG				4.50		None	Not modeled	MUNI
PITTSP_7_UNIT 5	33105	PTSB 5	18	312.00	1	Pittsburg		Market
PITTSP_7_UNIT 6	33106	PTSB 6	18	317.00	1	Pittsburg		Market
PITTSP_7_UNIT 7	30000	PTSB 7	20	682.00	1	Pittsburg		Market
RICHMN_7_BAYENV				2.00		None	Not modeled Aug NQC	QF/Selfgen
RVRVEW_1_UNITA1	33178	RVEC_GEN	13.8	46.00	1	Contra Costa	Aug NQC	Market
SEAWST_6_LAPOS	35312	SEAWESTF	9.11	0.31	1	Contra Costa	Aug NQC	Wind
SRINTL_6_UNIT	33468	SRI INTL	9.11	0.63	1	None	Aug NQC	QF/Selfgen
STAUFF_1_UNIT	33139	STAUFER	9.11	0.03	1	None	Aug NQC	QF/Selfgen
STOILS_1_UNITS	32921	CHEVGEN1	13.8	1.41	1	Pittsburg	Aug NQC	QF/Selfgen
STOILS_1_UNITS	32922	CHEVGEN2	13.8	1.41	1	Pittsburg	Aug NQC	QF/Selfgen
TIDWTR_2_UNITS	33151	FOSTER W	12.5	5.59	1	Pittsburg	Aug NQC	QF/Selfgen
TIDWTR_2_UNITS	33151	FOSTER W	12.5	5.59	2	Pittsburg	Aug NQC	QF/Selfgen
TIDWTR_2_UNITS	33151	FOSTER W	12.5	5.59	3	Pittsburg	Aug NQC	QF/Selfgen
UNCHEM_1_UNIT	32920	UNION CH	9.11	14.68	1	Pittsburg	Aug NQC	QF/Selfgen
UNOCAL_1_UNITS	32910	UNOCAL	12	0.00	1	Pittsburg	Aug NQC	QF/Selfgen
UNOCAL_1_UNITS	32910	UNOCAL	12	0.00	2	Pittsburg	Aug NQC	QF/Selfgen
UNOCAL_1_UNITS	32910	UNOCAL	12	0.00	3	Pittsburg	Aug NQC	QF/Selfgen
UNTDQF_7_UNITS	33466	UNTED CO	9.11	22.96	1	None	Aug NQC	QF/Selfgen
USWNDR_2_SMUD	32169	SOLANOWP	21	12.79	1	Contra Costa	Aug NQC	Wind
USWNDR_2_UNITS	32168	EXNCO	9.11	21.68	1	Contra Costa	Aug NQC	Wind
USWPFK_6_FRICK	35320	USW FRIC	12	0.64	1	Contra Costa	Aug NQC	Wind
USWPFK_6_FRICK	35320	USW FRIC	12	0.64	2	Contra Costa	Aug NQC	Wind
USWPJR_2_UNITS	33838	USWP_#3	9.11	2.27	1	Contra Costa	Aug NQC	Wind
WNDMAS_2_UNIT 1	33170	WINDMSTR	9.11	2.62	1	Contra Costa	Aug NQC	Wind
ZOND_6_UNIT	35316	ZOND SYS	9.11	4.70	1	Contra Costa	Aug NQC	Wind
IBMCTL_1_UNIT 1	35637	IBM-CTLE	115	0.00	1	San Jose	No NQC - hist. data	Market
IMHOFF_1_UNIT 1	33136	CCCSD	12.5	4.40	1	Pittsburg	No NQC - hist. data	QF/Selfgen

SHELRF_1_UNITS	33141	SHELL 1	12.5	20.00	1	Pittsburg	No NQC - hist. data	QF/Selfgen
SHELRF_1_UNITS	33142	SHELL 2	12.5	40.00	1	Pittsburg	No NQC - hist. data	QF/Selfgen
SHELRF_1_UNITS	33143	SHELL 3	12.5	40.00	1	Pittsburg	No NQC - hist. data	QF/Selfgen
ZANKER_1_UNIT 1	35861	SJ-SCL W	9.11	5.00	1	San Jose	No NQC - hist. data	QF/Selfgen
BRDSLD_2_MTZUMA	32171	HIGHWND3	34.5	10.00	1	Contra Costa	No NQC - est. data	Wind
New Unit	32179	T222	0.69	19.5	1	Contra Costa	No NQC - est. data	Wind
New Unit	32186	P0609	34.5	40	1	Contra Costa	No NQC - est. data	Wind
New Unit	32188	P0611G	34.5	7.5	1	Contra Costa	No NQC - est. data	Wind
New Unit	32190	Q039	0.58	24.9	1	Contra Costa	No NQC - est. data	Wind
New Unit	35304	Q045CTG1	15	0.00	1	None	Delayed	Market
New Unit	35305	Q045CTG2	15	0.00	1	None	Delayed	Market
New Unit	35306	Q067STG1	15	0.00	1	None	Delayed	Market
POTRPP_7_UNIT 3	33252	POTRERO3	20	0.00	1	None	Retired	Market
POTRPP_7_UNIT 4	33253	POTRERO4	13.8	0.00	1	None	Retired	Market
POTRPP_7_UNIT 5	33254	POTRERO5	13.8	0.00	1	None	Retired	Market
POTRPP_7_UNIT 6	33255	POTRERO6	13.8	0.00	1	None	Retired	Market

Major new projects modeled:

1. AHW #1 & #2 115kV Re-Cabling
2. New TransBay DC cable
3. New Oakland C-X #3 115kV Cable
4. San Mateo – Bay Meadows 115kV #1 & #2 Line Reconductoring
5. Four Wind farms connected to Birds Landing (~ 340 MW P max)
6. Retirement of Potrero #3, #4, #5 and #6

<u>Critical Contingency Analysis Summary</u>

San Francisco Sub-area

LCR need has been eliminated due to the Trans Bay DC cable and re-cabling of the AHW #1 and # 2 115 kV.

Oakland Sub-area

The most critical contingency is an outage of the C-X #2 and #3 115 kV cables. The area limitation is thermal overloading of the D-L 115 kV lines. This limiting contingency establishes a LCR of 55 MW in 2012 (includes 49 MW of Muni generation) as the minimum capacity necessary for reliable load serving capability within this sub-area.

This Oakland requirement does not include the need for Pittsburg/Oakland sub-area.

Effectiveness factors:

All units within this area have the same effectiveness factor. Units outside of this area are not effective.

Llagas Sub-area

The most critical contingency is an outage between Metcalf D and Morgan Hill 115 kV (with one of the Gilroy Peaker off-line). The area limitation is thermal overloading of the Metcalf-Llagas 115 kV line as well as voltage drop (5%) at the Morgan Hill substation. As documented within a CAISO Operating Procedure, this limitation is dependent on power flowing in the direction from Metcalf to Llagas/Morgan Hill. This limiting contingency establishes a LCR of 100 MW in 2012 (includes 0 MW of QF and Muni generation) as the minimum capacity necessary for reliable load serving capability within this sub-area.

Effectiveness factors:

All units within this area have the same effectiveness factor. Units outside of this area are not effective.

San Jose Sub-area

The most critical contingency is an outage of Metcalf-El Patio #1 or #2 115 kV line followed by Metcalf-Evergreen #1 115 kV line. The area limitation is thermal overloading of the Evergreen – San Jose B 115 kV line. This limiting contingency establishes a LCR of 352 MW in 2012 (includes 53 MW of QF and 202 MW of Muni generation) as the minimum capacity necessary for reliable load serving capability within this sub-area.

Effectiveness factors:

The following table has units within the Bay Area that are at least 5% effective to the above-mentioned constraint.

Gen Bus	Gen Name	Gen ID	Eff Fctr (%)
35863	CATALYST	1	20
36856	CCCA100	1	6
36854	Cogen	1	6
36854	Cogen	2	6
36863	DVRaGT1	1	6
36864	DVRbGT2	1	6
36865	DVRaST3	1	6
35860	OLS-AGNE	1	5
36858	Gia100	1	5
36859	Gia200	2	5
35854	LECEFGT1	1	5
35855	LECEFGT2	2	5
35856	LECEFGT3	3	5
35857	LECEFGT4	4	5

Pittsburg and Oakland Sub-area Combined

The most critical contingency is an outage of the Moraga #3 230/115 kV transformer combined with the loss of Delta Energy Center. The sub-area area limitation is thermal overloading of Moraga #1 230/115 kV transformer. This limiting contingency establishes a LCR of 3008 MW in 2012 (including 448 MW of QF/Muni generation) as the minimum capacity necessary for reliable load serving capability within this sub-area.

The most critical single contingency is an outage of the Moraga #3 230/115 kV transformer. The sub-area area limitation is thermal overloading of the Moraga #1 230/115 kV transformer. This limiting contingency establishes a LCR of 2729 MW in

2012 (including 448 MW of QF/Muni generation).

Effectiveness factors:

Please see Bay Area overall.

Contra Costa Sub-area

The most critical contingency is an outage of Kelso-Tesla 230 kV with the Gateway off line. The area limitation is thermal overloading of the Delta Switching Yard-Tesla 230 kV line. This limiting contingency establishes a LCR of 875 MW in 2012 (includes 52 MW of QF and 259 MW of Wind generation and 264 MW of MUNI pumps) as the minimum capacity necessary for reliable load serving capability within this sub-area.

Effectiveness factors:

The following table has units within the Bay Area that are at least 10% effective to the above-mentioned constraint.

Gen Bus	Gen Name	Gen ID	Eff Fctr (%)
33175	ALTAMONT	1	83
38760	DELTA E	10	71
38760	DELTA E	11	71
38765	DELTA D	8	71
38765	DELTA D	9	71
38770	DELTA C	6	71
38770	DELTA C	7	71
38815	DELTA B	4	71
38815	DELTA B	5	71
38820	DELTA A	3	71
33170	WINDMSTR	1	68
33118	GATEWAY1	1	23
33119	GATEWAY2	1	23
33120	GATEWAY3	1	23
33116	C.COS 6	1	23
33117	C.COS 7	1	23
33133	GWF #3	1	23
33134	GWF #4	1	23
33178	RVEC_GEN	1	23
33131	GWF #1	1	22
32179	T222	1	18
32188	P0611G	1	18
32190	Q039	1	18

32186	P0609	1	18
32171	HIGHWND3	1	18
32177	Q0024	1	18
32168	ENXCO	2	18
32169	SOLANOWP	1	18
32172	HIGHWNDS	1	18
32176	SHILOH	1	18
33838	USWP_#3	1	18
32173	LAMBGT1	1	14
32174	GOOSEHGT	2	14
32175	CREEDGT1	3	14
35312	SEAWESTF	1	11
35316	ZOND SYS	1	11
35320	USW FRIC	1	11

Bay Area overall

As the aggregate sub pocket LCR is adequate to cover the overall Bay area contingency,

- Sum of the sub pockets for Category B is binding at 3647 MW
- Sum of the sub pockets for Category C is binding at 4278 MW

Effectiveness factors:

For most helpful procurement information please read procedure T-133Z effectiveness factors (posted under M-403Z) at: http://www.caiso.com/237e/237eda4b5070.pdf

Changes compared to last year's results:

Overall the load forecast went down by 368 MW. As a result, LCR decreases by 426 MW. Due to the significantly increased Delta pump load (from 157 MW to 264 MW), a new pocket is modeled this year to calculate the LCR for the effective generation to mitigate a contingency in this sub-pocket. Furthermore the sum of the sub pocket LCR needs is adequate to cover the overall Bay area contingency. Therefore, no additional LCR is needed for the overall Bay area.

Bay Area Overall Requirements:

2012	Wind (MW)	QF/Selfgen (MW)	Muni (MW)	Market (MW)	Max. Qualifying Capacity (MW)
Available generation	261	532	519	5276	6588

2012	Existing Generation Capacity Needed (MW)	Deficiency (MW)	Total MW LCR Need
Category B (Single)[17]	3647	0	3647
Category C (Multiple)[18]	4278	0	4278

6. Greater Fresno Area

Area Definition

The transmission facilities coming into the Greater Fresno area are:

1) Gates-Gregg 230 kV Line
2) Gates-McCall 230 kV Line
3) Gates #1 230/70 kV Transformer Bank
4) Los Banos #3 230/70 kV Transformer Bank
5) Los Banos #4 230/70 kV Transformer Bank
6) Panoche-Helm 230 kV Line
7) Panoche-Kearney 230 kV Line
8) Panoche #1 230/115 kV Transformer
9) Panoche #2 230/115 kV Transformer
10) Warnerville-Wilson 230 kV Line
11) Wilson-Melones 230 kV Line
12) Smyrna-Corcoran 115kV Line
13) Coalinga #1-San Miguel 70 kV Line

The substations that delineate the Greater Fresno area are:

1) Gates is out Henrietta is in
2) Gates is out Henrietta is in
3) Gates 230 kV is out Gates 70 kV is in
4) Los Banos 230 kV is out Los Banos 70 kV is in
5) Los Banos 230 kV is out Los Banos 70 kV is in

[17] A single contingency means that the system will be able the survive the loss of a single element, however the operators will not have any means (other then load drop) in order to bring the system within a safe operating zone and get prepared for the next contingency as required by MORC.

[18] Multiple contingencies means that the system will be able the survive the loss of a single element, and the operators will have enough generation (other operating procedures) in order to bring the system within a safe operating zone and get prepared for the next contingency as required by MORC.

6) Panoche is out Helm is in
7) Panoche is out Mc Mullin is in
8) Panoche 115 kV is in Panoche 230 kV is out
9) Panoche 115 kV is in Panoche 230 kV is out
10) Warnerville is out Wilson is in
11) Wilson is in Melones is out
12) Quebec SP is out Corcoran is in
13) Coalinga is in San Miguel is out

2012 total busload within the defined area is 3014 MW with 105 MW of losses resulting in a total (load plus losses) of 3120 MW.

Total units and qualifying capacity available in this area:

MKT/SCHED RESOURCE ID	BUS #	BUS NAME	kV	NQC	UNIT ID	LCR SUB-AREA NAME	NQC Comments	CAISO Tag
AGRICO_6_PL3N5	34608	AGRICO	13.8	16.00	3	Wilson, Herndon		Market
AGRICO_7_UNIT	34608	AGRICO	13.8	43.05	2	Wilson, Herndon		Market
AGRICO_7_UNIT	34608	AGRICO	13.8	7.45	4	Wilson, Herndon		Market
BALCHS_7_UNIT 1	34624	BALCH	13.2	34.00	1	Wilson, Herndon	Aug NQC	Market
BALCHS_7_UNIT 2	34612	BLCH	13.8	52.50	1	Wilson, Herndon	Aug NQC	Market
BALCHS_7_UNIT 3	34614	BLCH	13.8	52.50	1	Wilson, Herndon	Aug NQC	Market
BORDEN_2_QF	30805	BORDEN	230	0.68		Wilson	Not modeled Aug NQC	QF/Selfgen
BULLRD_7_SAGNES				0.00		Wilson	Not modeled Aug NQC	QF/Selfgen
CAPMAD_1_UNIT 1	34179	MADERA_G	13.8	17.00	1	Wilson		Market
CHEVCO_6_UNIT 1	34652	CHV.COAL	9.11	7.69	1	Wilson	Aug NQC	QF/Selfgen
CHEVCO_6_UNIT 2	34652	CHV.COAL	9.11	1.62	2	Wilson	Aug NQC	QF/Selfgen
CHWCHL_1_BIOMAS	34305	CHWCHLA2	13.8	5.76	1	Wilson, Herndon	Aug NQC	Market
CHWCHL_1_UNIT	34301	CHOWCOGN	13.8	48.00	1	Wilson, Herndon		Market
COLGA1_6_SHELLW	34654	COLNGAGN	9.11	35.57	1	Wilson	Aug NQC	QF/Selfgen
CRESSY_1_PARKER	34140	CRESSEY	115	1.20		Wilson	Not modeled Aug NQC	MUNI
CRNEVL_6_CRNVA				0.71		Wilson	Not modeled Aug NQC	Market

CRNEVL_6_SJQN 2	34631	SJ2GEN	9.11	3.20	1	Wilson	Aug NQC	Market
CRNEVL_6_SJQN 3	34633	SJ3GEN	9.11	4.20	1	Wilson	Aug NQC	Market
DINUBA_6_UNIT	34648	DINUBA E	13.8	9.87	1	Wilson, Herndon		Market
ELNIDP_6_BIOMAS	34330	ELNIDO	13.8	5.66	1	Wilson	Aug NQC	Market
EXCHEC_7_UNIT 1	34306	EXCHQUER	13.8	61.77	1	Wilson	Aug NQC	MUNI
FRIANT_6_UNITS	34636	FRIANTDM	6.6	5.29	2	Wilson	Aug NQC	QF/Selfgen
FRIANT_6_UNITS	34636	FRIANTDM	6.6	2.83	3	Wilson	Aug NQC	QF/Selfgen
FRIANT_6_UNITS	34636	FRIANTDM	6.6	0.75	4	Wilson	Aug NQC	QF/Selfgen
GATES_6_PL1X2	34553	WHD_GAT2	13.8	41.50	1	Wilson		Market
GWFPWR_1_UNITS	34431	GWF_HEP1	13.8	42.20	1	Wilson, Herndon		Market
GWFPWR_1_UNITS	34433	GWF_HEP2	13.8	42.20	1	Wilson, Herndon		Market
GWFPWR_6_UNIT	34650	GWF-PWR.	9.11	24.03	1	Wilson, Henrietta	Aug NQC	QF/Selfgen
HAASPH_7_PL1X2	34610	HAAS	13.8	68.15	1	Wilson, Herndon	Aug NQC	Market
HAASPH_7_PL1X2	34610	HAAS	13.8	68.15	2	Wilson, Herndon	Aug NQC	Market
HELMPG_7_UNIT 1	34600	HELMS	18	404.00	1	Wilson	Aug NQC	Market
HELMPG_7_UNIT 2	34602	HELMS	18	404.00	2	Wilson	Aug NQC	Market
HELMPG_7_UNIT 3	34604	HELMS	18	404.00	3	Wilson	Aug NQC	Market
HENRTA_6_UNITA1	34539	GWF_GT1	13.8	45.33	1	Wilson, Henrietta		Market
HENRTA_6_UNITA2	34541	GWF_GT2	13.8	45.23	1	Wilson, Henrietta		Market
INTTRB_6_UNIT	34342	INT.TURB	9.11	1.63	1	Wilson	Aug NQC	QF/Selfgen
JRWOOD_1_UNIT 1	34332	JRWCOGEN	9.11	3.68	1	Wilson	Aug NQC	QF/Selfgen
KERKH1_7_UNIT 1	34344	KERCKHOF	6.6	13.00	1	Wilson, Herndon	Aug NQC	Market
KERKH1_7_UNIT 2	34344	KERCKHOF	6.6	8.50	2	Wilson, Herndon	Aug NQC	Market
KERKH1_7_UNIT 3	34344	KERCKHOF	6.6	12.80	3	Wilson, Herndon	Aug NQC	Market
KERKH2_7_UNIT 1	34308	KERCKHOF	13.8	153.90	1	Wilson, Herndon	Aug NQC	Market
KINGCO_1_KINGBR	34642	KINGSBUR	9.11	23.31	1	Wilson, Herndon	Aug NQC	QF/Selfgen
KINGRV_7_UNIT 1	34616	KINGSRIV	13.8	51.20	1	Wilson, Herndon	Aug NQC	Market
MALAGA_1_PL1X2	34671	KRCDPCT1	13.8	48.00	1	Wilson, Herndon		Market
MALAGA_1_PL1X2	34672	KRCDPCT2	13.8	48.00	1	Wilson, Herndon		Market
MCCALL_1_QF				0.72		Wilson, Herndon	Not modeled Aug NQC	QF/Selfgen
MCSWAN_6_UNITS	34320	MCSWAIN	9.11	4.57	1	Wilson	Aug NQC	MUNI
MENBIO_6_UNIT	34334	BIO PWR	9.11	21.61	1	Wilson	Aug NQC	QF/Selfgen
MERCFL_6_UNIT	34322	MERCEDFL	9.11	2.03	1	Wilson	Aug NQC	Market
PINFLT_7_UNITS	38720	PINEFLAT	13.8	33.12	1	Wilson, Herndon	Aug NQC	MUNI

PINFLT_7_UNITS	38720	PINEFLAT	13.8	33.12	2	Wilson, Herndon	Aug NQC	MUNI
PINFLT_7_UNITS	38720	PINEFLAT	13.8	33.13	3	Wilson, Herndon	Aug NQC	MUNI
PNCHPP_1_PL1X2	34328	STARGT1	13.8	55.58	1	Wilson		Market
PNCHPP_1_PL1X2	34329	STARGT2	13.8	55.58	1	Wilson		Market
PNOCHE_1_PL1X2	34142	WHD_PAN2	13.8	40.00	1	Wilson, Herndon		Market
PNOCHE_1_UNITA1	34186	DG_PAN1	13.8	42.78	1	Wilson		Market
SGREGY_6_SANGER	34646	SANGERCO	9.11	26.96	1	Wilson	Aug NQC	QF/Selfgen
STOREY_7_MDRCHW				0.88		Wilson	Not modeled Aug NQC	QF/Selfgen
ULTPFR_1_UNIT 1	34640	ULTR.PWR	9.11	17.30	1	Wilson, Herndon	Aug NQC	QF/Selfgen
WISHON_6_UNITS	34658	WISHON	2.3	4.51	1	Wilson	Aug NQC	Market
WISHON_6_UNITS	34658	WISHON	2.3	4.51	2	Wilson	Aug NQC	Market
WISHON_6_UNITS	34658	WISHON	2.3	4.51	3	Wilson	Aug NQC	Market
WISHON_6_UNITS	34658	WISHON	2.3	4.51	4	Wilson	Aug NQC	Market
WISHON_6_UNITS	34658	WISHON	2.3	0.36	5	Wilson	Aug NQC	Market
WRGHTP_7_AMENGY				0.53		Wilson	Not modeled Aug NQC	QF/Selfgen
NA	34485	FRESNOWW	12.5	9.00	1	Wilson	No NQC - hist. data	QF/Selfgen
NA	34485	FRESNOWW	12.5	4.00	2	Wilson	No NQC - hist. data	QF/Selfgen
NA	34485	FRESNOWW	12.5	1.00	3	Wilson	No NQC - hist. data	QF/Selfgen
ONLLPP_6_UNIT 1	34316	ONEILPMP	9.11	0.50	1	Wilson	No NQC - hist. data	MUNI
MENBIO_6_RENEW1	34339	CALRENEW	12.5	0.00	1	Wilson	Energy Only	Market
New Unit	34696	Q478	21	0.00	1	Wilson, Herndon	Energy Only	Market
New Unit	34603	JQBSWLT	12.5	0.00	ST	Wilson	Energy Only	Market

Major new projects modeled:

1. Herndon 230 to 115 kV Transformer bank # 3

<u>Critical Contingency Analysis Summary</u>

Wilson Sub-area

The Wilson sub-area largely defines the Fresno area import constraints. The main constrained spot is located at Warnerville-Wilson-Gregg 230 kV transmission corridor. Other constrained spots are located at the Gates-McCall, Gates-Gregg, Panoche-McCall and Panoche-Gregg 230 kV transmission corridors.

The most critical contingency is the loss of the Melones - Wilson 230 kV line overlapped with one of the Helms units out of service. This contingency would thermally overload the Warnerville - Wilson 230 kV line (most stringent) and possibly also the Gates-McCall 230 kV line. This limiting contingency establishes a LCR of 1873 MW in 2012 (includes 189 MW of QF and 167 MW of Muni generation) as the minimum generation capacity necessary for reliable load serving capability within this sub-area.

Effectiveness factors:

The following table has units within Fresno that are at least 5% effective to the constraint on the Warnerville – Wilson 230 kV line.

Gen Bus	Gen Name	Gen ID	Eff Fctr (%)
34332	JRWCOGEN	1	40%
34330	ELNIDO	1	37%
34322	MERCEDFL	1	35%
34320	MCSWAIN	1	34%
34306	EXCHQUER	1	34%
34305	CHWCHLA2	1	32%
34301	CHOWCOGN	1	32%
34658	WISHON	1	28%
34658	WISHON	1	28%
34658	WISHON	1	28%
34658	WISHON	1	28%
34658	WISHON	1	28%
34631	SJ2GEN	1	28%
34633	SJ3GEN	1	27%
34636	FRIANTDM	2	27%
34636	FRIANTDM	3	27%
34636	FRIANTDM	4	27%
34600	HELMS 1	1	27%
34602	HELMS 2	1	27%
34604	HELMS 3	1	27%
34308	KERCKHOF	1	26%
34344	KERCKHOF	1	26%
34344	KERCKHOF	2	26%
34344	KERCKHOF	3	26%
34485	FRESNOWW	1	24%
34648	DINUBA E	1	22%

34179	MADERA_G	1	22%
34616	KINGSRIV	1	22%
34624	BALCH 1	1	21%
34671	KRCDPCT1	1	21%
34672	KRCDPCT2	1	21%
34640	ULTR.PWR	1	21%
34646	SANGERCO	1	21%
34642	KINGSBUR	1	19%
34696	Q478	1	18%
34610	HAAS	1	18%
34610	HAAS	1	18%
34614	BLCH 2-3	1	18%
34612	BLCH 2-2	1	17%
38720	PINE FLT	1	17%
38720	PINE FLT	2	17%
38720	PINE FLT	3	17%
34431	GWF_HEP1	1	17%
34433	GWF_HEP2	1	17%
34334	BIO PWR	1	14%
34608	AGRICO	2	14%
34608	AGRICO	3	14%
34608	AGRICO	4	14%
34539	GWF_GT1	1	14%
34541	GWF_GT2	1	14%
34650	GWF-PWR.	1	13%
34186	DG_PAN1	1	11%
34142	WHD_PAN2	1	11%
34652	CHV.COAL	1	10%
34652	CHV.COAL	2	10%
34553	WHD_GAT2	1	9%
34654	COLNGAGN	1	9%
34342	INT.TURB	1	6%
34316	ONEILPMP	1	6%

Herndon Sub-area

The most critical contingency is the loss of the Herndon -Barton 115 kV line along with Herndon-Woodward 115 kV line. This contingency could thermally overload the Herndon–Manchester 115 kV line. This limiting contingency establishes a LCR of 275 MW (includes 41 MW of QF and 99 MW of Muni generation) in 2011 as the minimum generation capacity necessary for reliable load serving capability within this sub-area.

The Category B LCR requirement for the Herndon sub area was eliminated due to the construction of the new Herndon# 3 230/115 kV transformer bank.

Effectiveness factors:

The following table has units within Fresno area that are relatively effective to the above-mentioned constraint.

Gen Bus	Gen Name	Gen ID	Eff Fctr (%)
34308	KERCKHOF	1	34%
34344	KERCKHOF	1	34%
34344	KERCKHOF	2	34%
34344	KERCKHOF	3	34%
34624	BALCH 1	1	33%
34646	SANGERCO	1	31%
34616	KINGSRIV	1	31%
34671	KRCDPCT1	1	31%
34672	KRCDPCT2	1	31%
34640	ULTR.PWR	1	30%
34648	DINUBA E	1	28%
34642	KINGSBUR	1	25%
34696	Q478	1	25%
38720	PINE FLT	1	23%
38720	PINE FLT	2	23%
38720	PINE FLT	3	23%
34610	HAAS	1	23%
34610	HAAS	2	23%
34614	BLCH 2-3	1	23%
34612	BLCH 2-2	1	23%
34431	GWF_HEP1	1	14%
34433	GWF_HEP2	1	14%
34301	CHOWCOGN	1	9%
34305	CHWCHLA2	1	9%
34608	AGRICO	2	7%
34608	AGRICO	3	7%
34608	AGRICO	4	7%
34332	JRWCOGEN	1	-6%
34600	HELMS 1	1	-12%
34602	HELMS 2	1	-12%
34604	HELMS 3	1	-12%
34485	FRESNOWW	1	-14%

Henrietta Sub-area

The two most critical contingencies listed below together establish a local capacity need of 68 MW (includes 24 MW of QF as well as 8 MW of deficiency) in 2012 as the minimum capacity necessary for reliable load serving capability within this sub-area.

The most critical contingency is the loss of Henrietta 230/70 kV transformer bank #4 and GWF Power unit. This contingency could thermally overload the Henrietta 230/70 kV transformer bank #2. This limiting contingency establishes a LCR of 36 MW in 2011 (includes 0 MW of QF generation).

The second most critical contingency is the loss of Henrietta 230/70 kV transformer bank #4 and one of the Henrietta-GWF Henrietta 70 kV line. This contingency could thermally overload the Henrietta 230/70 kV transformer bank #2. This limiting contingency establishes a LCR of 32 MW in 2011 (includes 24 MW of QF generation as well as 8 MW of deficiency).

The most critical single contingency is the loss of Henrietta 230/70 kV transformer bank #4. This contingency could thermally overload the Henrietta 230/70 kV transformer bank #2. This limiting contingency establishes a LCR of 35 MW in 2012 (includes 24 MW of QF generation).

Effectiveness factors:

All units within this sub-area have the same effectiveness factor. Units outside of this sub-area are not effective.

Changes compared to last year's results:

Overall the load forecast is down by 186 MW. Path 15 flow is 1275 MW N-S the same as last year. Due to the new Herndon # 3 230/115 kV bank & lower load forecast, the total Fresno LCR requirement has decreased by 542 MW.

Fresno Area Overall Requirements:

2012	QF/Selfgen (MW)	Muni (MW)	Market (MW)	Max. Qualifying Capacity (MW)
Available generation	189	167	2414	2770

2012	Existing Generation Capacity Needed (MW)	Deficiency (MW)	Total MW LCR Need
Category B (Single) [19]	1873	0	1873
Category C (Multiple) [20]	1899	8	1907

[19] A single contingency means that the system will be able the survive the loss of a single element, however the operators will not have any means (other then load drop) in order to bring the system within a safe operating zone and get prepared for the next contingency as required by MORC.

7. Kern Area

Area Definition

The transmission facilities coming into the Kern PP sub-area are:

1) Wheeler Ridge-Lamont 115 kV line
2) Kern PP 230/115 kV Bank # 3
3) Kern PP 230/115 kV Bank # 4
4) Kern PP 230/115 kV Bank # 5
5) Midway 230/115 Bank # 1
6) Midway 230/115 Bank # 2
7) Midway 230/115 Bank #3
8) Temblor – San Luis Obispo 115 kV line

The substations that delineate the Kern-PP sub-area are:

1) Wheeler Ridge is out Lamont is in
2) Kern PP 230 kV is out Kern PP 115 kV is in
3) Kern PP 230 kV is out Kern PP 115 kV is in
4) Kern PP 230 kV is out Kern PP 115 kV is in
5) Midway 230 kV is out Midway 115 kV is in
6) Midway 230 kV is out Midway 115 kV is in
7) Midway 230 kV is out Midway 115 kV is in
8) Temblor is in San Luis Obispo is out

The transmission facilities coming into the Weedpatch sub-area are:

1) Wheeler Ridge-Tejon 60 kV line
2) Wheeler Ridge-Weedpach 60 kV line
3) Wheeler Ridge-San Bernard 60 kV line

The substations that delineate the Weedpatch sub-area are:

1) Wheeler Ridge is out Tejon is in
2) Wheeler Ridge is out Weedpach is in
3) Wheeler Ridge is out San Bernard is in

2012 total busload within the defined area: 1099 MW with 11 MW of losses resulting in

[20] Multiple contingencies means that the system will be able the survive the loss of a single element, and the operators will have enough generation (other operating procedures) in order to bring the system within a safe operating zone and get prepared for the next contingency as required by MORC.

a total (load plus losses) of 1110 MW.

Total units and qualifying capacity available in this Kern area:

MKT/SCHED RESOURCE ID	BUS #	BUS NAME	kV	NQC	UNIT ID	LCR SUB-AREA NAME	NQC Comments	CAISO Tag
BDGRCK_1_UNITS	35029	BADGERCK	9.11	42.21	1	Kern PP	Aug NQC	QF/Selfgen
BEARMT_1_UNIT	35066	PSE-BEAR	9.11	45.79	1	Kern PP, West Park	Aug NQC	QF/Selfgen
CHALK_1_UNIT	35038	CHLKCLF+	9.11	45.27	1	Kern PP	Aug NQC	QF/Selfgen
CHEVCD_6_UNIT	35052	CHEV.USA	9.11	1.27	1	Kern PP	Aug NQC	QF/Selfgen
CHEVCY_1_UNIT	35032	CHV-CYMR	9.11	5.24	1	Kern PP	Aug NQC	QF/Selfgen
DEXZEL_1_UNIT	35024	DEXEL +	9.11	28.24	1	Kern PP	Aug NQC	QF/Selfgen
DISCOV_1_CHEVRN	35062	DISCOVRY	9.11	1.70	1	Kern PP	Aug NQC	QF/Selfgen
DOUBLC_1_UNITS	35023	DOUBLE C	9.11	37.59	1	Kern PP	Aug NQC	QF/Selfgen
FELLOW_7_QFUNTS				1.28		Kern PP	Not modeled Aug NQC	QF/Selfgen
FRITO_1_LAY	35048	FRITOLAY	9.11	0.09	1	Kern PP	Aug NQC	QF/Selfgen
KERNFT_1_UNITS	35026	KERNFRNT	9.11	37.60	1	Kern PP	Aug NQC	QF/Selfgen
KERNRG_1_UNITS	35040	KERNRDGE	9.11	0.51	1	Kern PP	Aug NQC	QF/Selfgen
KERNRG_1_UNITS	35040	KERNRDGE	9.11	0.51	2	Kern PP	Aug NQC	QF/Selfgen
KRNCNY_6_UNIT	35018	KERNCNYN	9.11	9.38	1	Weedpatch	Aug NQC	Market
KRNOIL_7_TEXEXP				6.11		Kern PP	Not modeled Aug NQC	QF/Selfgen
LIVOAK_1_UNIT 1	35058	PSE-LVOK	9.11	44.40	1	Kern PP	Aug NQC	QF/Selfgen
MIDSET_1_UNIT 1	35044	TX MIDST	9.11	33.56	1	Kern PP	Aug NQC	QF/Selfgen
MIDWAY_1_QF				0.03		Kern PP	Not modeled Aug NQC	QF/Selfgen
MKTRCK_1_UNIT 1	35060	PSEMCKIT	9.11	43.07	1	Kern PP	Aug NQC	QF/Selfgen
MTNPOS_1_UNIT	35036	MT POSO	9.11	43.39	1	Kern PP	Aug NQC	QF/Selfgen
NAVY35_1_UNITS	35064	NAVY 35R	9.11	0.00	1	Kern PP	Aug NQC	QF/Selfgen
NAVY35_1_UNITS	35064	NAVY 35R	9.11	0.00	2	Kern PP	Aug NQC	QF/Selfgen
OILDAL_1_UNIT 1	35028	OILDALE	9.11	37.50	1	Kern PP	Aug NQC	QF/Selfgen
RIOBRV_6_UNIT 1	35020	RIOBRAVO	9.11	6.50	1	Weedpatch	Aug NQC	QF/Selfgen
SIERRA_1_UNITS	35027	HISIERRA	9.11	42.98	1	Kern PP	Aug NQC	QF/Selfgen
TANHIL_6_SOLART	35050	SLR-TANN	9.11	9.79	1	Kern PP	Aug NQC	QF/Selfgen
TEMBLR_7_WELLPT				0.30		Kern PP	Not modeled Aug NQC	QF/Selfgen
TXMCKT_6_UNIT				4.12		Kern PP	Not modeled Aug NQC	QF/Selfgen
TXNMID_1_UNIT 2	34783	TEXCO_NM	9.11	0.01	1	Kern PP	Aug NQC	QF/Selfgen
TXNMID_1_UNIT 2	34783	TEXCO_NM	9.11	0.01	2	Kern PP	Aug NQC	QF/Selfgen
ULTOGL_1_POSO	35035	ULTR PWR	9.11	34.70	1	Kern PP	Aug NQC	QF/Selfgen
UNVRSY_1_UNIT 1	35037	UNIVRSTY	9.11	31.66	1	Kern PP	Aug NQC	QF/Selfgen
VEDDER_1_SEKERN	35046	SEKR	9.11	8.01	1	Kern PP	Aug NQC	QF/Selfgen
MIDSUN_1_PL1X2	35034	MIDSUN +	9.11	0.00	1	Kern PP	Retired	Market
NA	35056	TX-LOSTH	4.16	8.80	1	Kern PP	No NQC - hist. data	QF/Selfgen
New Unit	35000	Q340	21	0.00	1	Kern PP	Energy Only	Market
New Unit	35012	Q473	21	0.00	1	Kern PP	Energy Only	Market
New Unit	35013	Q479	21	0.00	1	Kern PP	Energy Only	Market

Major new projects modeled:

1. Kern Bank 3 & 3a 230/115 kV bank replacement
2. Midway Bank 2 & 2a 230/115 kV bank replacement

Critical Contingency Analysis Summary

Kern PP Sub-area

The most critical contingency is the outage of the Kern PP #5/#3 230/115 kV transformer bank followed by the Kern PP – Kern Front 115 kV line, which could thermally overload the parallel Kern PP #4 230/115 kV transformer. This limiting contingency establishes a LCR of 296 MW in 2012 (includes 596 MW of QF generation) as the minimum generation capacity necessary for reliable load serving capability within this sub-area.

The most critical single contingency is the loss of Kern PP #5 or #3 230/115 kV transformer bank, which could thermally overload the parallel Kern PP #4230/115 kV transformer. This limiting contingency establishes a LCR of 180 MW in 2012 (includes 596 MW of QF generation).

Effectiveness factors:

The following table shows units that are at least 5% effective:

Gen Bus	Gen Name	Gen ID	Eff Fctr (%)
35066	PSE-BEAR	1	22%
35029	BADGERCK	1	22%
35023	DOUBLE C	1	22%
35027	HISIERRA	1	22%
35026	KERNFRNT	1	21%
35058	PSE-LVOK	1	21%
35028	OILDALE	1	21%
35062	DISCOVRY	1	21%
35046	SEKR	1	21%
35024	DEXEL +	1	21%
35036	MT POSO	1	15%
35035	ULTR PWR	1	15%
35052	CHEV.USA	1	6%

Weedpatch Sub-area

The most critical contingency is the loss of the Wheeler Ridge – San Bernard 70 kV line followed by the Wheeler Ridge – Tejon 70 kV line, which could thermally overload the Wheeler Ridge – Weedpatch 70 kV line and cause low voltage problem at the local 70 kV transmission system. This limiting contingency establishes a LCR of 30 MW in 2012 (includes 7 MW of QF generation and 14 MW of deficiency) as the minimum generation capacity necessary for reliable load serving capability within this sub-area.

Effectiveness factors:

All units within this sub-area are needed therefore no effectiveness factor is required.

West Park Sub-area

The most critical contingency is the loss of common mode Kern - West Park # 1 & #2 115 kV lines, resulting in the overload of the 6/42 To Magunden section of Kern – Magunden - Witco 115 kV line. This limitation establishes a LCR of 60 MW (includes 46 MW of QF generation and 14 MW of deficiency).

Effectiveness factors:

All units within this sub-area are needed therefore no effectiveness factor is required.

Changes compared to last year's results:

Overall the load forecast went down by 277 MW and that drives the LCR down by 138 MW. The load reduction is less effective in mitigating the main Kern PP constraint compared to resources in the area.

Kern Area Overall Requirements:

2012	QF/Selfgen (MW)	Market (MW)	Max. Qualifying Capacity (MW)
Available generation	602	9	611

2012	Existing Generation Capacity Needed (MW)	Deficiency (MW)	Total MW LCR Need
Category B (Single) [21]	180	0	180
Category C (Multiple) [22]	297	28	325

[21] A single contingency means that the system will be able the survive the loss of a single element, however the operators will not have any means (other then load drop) in order to bring the system within a safe operating zone and get prepared for the next contingency as required by MORC.

8. LA Basin Area

<u>Area Definition</u>

The transmission tie lines into the LA Basin Area are:

1) San Onofre - San Luis Rey #1, #2, & #3 230 kV Lines
2) San Onofre - Talega #1 & #2 230 kV Lines
3) Lugo - Mira Loma #2 & #3 500 kV Lines
4) Lugo – Rancho Vista #1 500 kV line
5) Sylmar - Eagle Rock 230 kV Line
6) Sylmar - Gould 230 kV Line
7) Vincent - Mesa Cal 230 kV Line
8) Vincent - Rio Hondo #1 & #2 230 kV Lines
9) Eagle Rock - Pardee 230 kV Line
10) Devers - Palo Verde 500 kV Line
11) Mirage - Coachelv 230 kV Line
12) Mirage - Ramon 230 kV Line
13) Mirage - Julian Hinds 230 kV Line

These sub-stations form the boundary surrounding the LA Basin area:

1) San Onofre is in San Luis Rey is out
2) San Onofre is in Talega is out
3) Mira Loma is in Lugo is out
4) Rancho Vista is in Lugo is out
5) Eagle Rock is in Sylmar is out
6) Gould is in Sylmar is out
7) Mesa Cal is in Vincent is out
8) Rio Hondo is in Vincent is out
9) Eagle Rock is in Pardee is out
10) Devers is in Palo Verde is out
11) Mirage is in Coachelv is out
12) Mirage is in Ramon is out
13) Mirage is in Julian Hinds is out

[22] Multiple contingencies means that the system will be able the survive the loss of a single element, and the operators will have enough generation (other operating procedures) in order to bring the system within a safe operating zone and get prepared for the next contingency as required by MORC.

Total 2012 busload within the defined area is 19,774 MW with 129 MW of losses and 27 MW pumps resulting in total load + losses + pumps of 19,930 MW.

Total units and qualifying capacity available in the LA Basin area:

MKT/SCHED RESOURCE ID	BUS #	BUS NAME	kV	NQC	UNIT ID	LCR SUB-AREA NAME	NQC Comments	CAISO Tag
ALAMIT_7_UNIT 1	24001	ALAMT1 G	18	174.56	1	Western		Market
ALAMIT_7_UNIT 2	24002	ALAMT2 G	18	175.00	2	Western		Market
ALAMIT_7_UNIT 3	24003	ALAMT3 G	18	332.18	3	Western		Market
ALAMIT_7_UNIT 4	24004	ALAMT4 G	18	335.67	4	Western		Market
ALAMIT_7_UNIT 5	24005	ALAMT5 G	20	497.97	5	Western		Market
ALAMIT_7_UNIT 6	24161	ALAMT6 G	20	495.00	6	Western		Market
ANAHM_7_CT	25203	ANAHEIMG	13.8	40.64	1	Western	Aug NQC	MUNI
ARCOGN_2_UNITS	24011	ARCO 1G	13.8	56.62	1	Western	Aug NQC	QF/Selfgen
ARCOGN_2_UNITS	24012	ARCO 2G	13.8	56.62	2	Western	Aug NQC	QF/Selfgen
ARCOGN_2_UNITS	24013	ARCO 3G	13.8	56.62	3	Western	Aug NQC	QF/Selfgen
ARCOGN_2_UNITS	24014	ARCO 4G	13.8	56.62	4	Western	Aug NQC	QF/Selfgen
ARCOGN_2_UNITS	24163	ARCO 5G	13.8	28.31	5	Western	Aug NQC	QF/Selfgen
ARCOGN_2_UNITS	24164	ARCO 6G	13.8	28.32	6	Western	Aug NQC	QF/Selfgen
BARRE_2_QF	24016	BARRE	230	0.00		Western	Not modeled	QF/Selfgen
BARRE_6_PEAKER	28309	BARPKGEN	13.8	45.38	1	Western		Market
BRDWAY_7_UNIT 3	28007	BRODWYSC	13.8	65.00	1	Western		MUNI
BUCKWD_7_WINTCV	25634	BUCKWIND	115	0.11	W5	Eastern	Aug NQC	Wind
CABZON_1_WINDA1	28280	CABAZON	33	8.81	1	Eastern	Aug NQC	Wind
CENTER_2_QF	24203	CENTER S	66	17.99		Western	Not modeled Aug NQC	QF/Selfgen
CENTER_2_RHONDO	24203	CENTER S	66	1.91		Western	Not modeled	QF/Selfgen
CENTER_6_PEAKER	28308	CTRPKGEN	13.8	44.57	1	Western		Market
CENTRY_6_PL1X4				36.00		Eastern	Not modeled Aug NQC	Market
CHEVMN_2_UNITS	24022	CHEVGEN1	13.8	0.15	1	Western, El Nido	Aug NQC	QF/Selfgen
CHEVMN_2_UNITS	24023	CHEVGEN2	13.8	0.16	2	Western, El Nido	Aug NQC	QF/Selfgen
CHINO_2_QF	24024	CHINO	66	9.30		Western	Not modeled Aug NQC	QF/Selfgen
CHINO_6_CIMGEN	24026	CIMGEN	13.8	25.07	1	Western	Aug NQC	QF/Selfgen
CHINO_6_SMPPAP	24140	SIMPSON	13.8	25.07	1	Western	Aug NQC	QF/Selfgen
CHINO_6_SOLAR	24024	CHINO	66	0.00		Western	Not modeled	Market
CHINO_7_MILIKN	24024	CHINO	66	1.26		Western	Not modeled Aug NQC	Market
COLTON_6_AGUAM1				43.00		Eastern	Not modeled	MUNI
CORONS_6_CLRWTR	24210	MIRALOMA	66	14.00		Eastern	Not modeled	MUNI
CORONS_6_CLRWTR	24210	MIRALOMA	66	14.00		Eastern	Not modeled	MUNI
DEVERS_1_QF	25645	VENWIND	115	1.08	EU	Eastern	Aug NQC	QF/Selfgen
DEVERS_1_QF	25635	ALTWIND	115	0.96	Q1	Eastern	Aug NQC	QF/Selfgen
DEVERS_1_QF	25636	RENWIND	115	0.42	Q1	Eastern	Aug NQC	QF/Selfgen
DEVERS_1_QF	25645	VENWIND	115	2.53	Q1	Eastern	Aug NQC	QF/Selfgen
DEVERS_1_QF	25646	SANWIND	115	0.57	Q1	Eastern	Aug NQC	QF/Selfgen
DEVERS_1_QF	25635	ALTWIND	115	1.77	Q2	Eastern	Aug NQC	QF/Selfgen
DEVERS_1_QF	25636	RENWIND	115	1.61	Q2	Eastern	Aug NQC	QF/Selfgen
DEVERS_1_QF	25645	VENWIND	115	1.71	Q2	Eastern	Aug NQC	QF/Selfgen

DEVERS_1_QF	25646	SANWIND	115	1.90	Q2	Eastern	Aug NQC	QF/Selfgen
DEVERS_1_QF	24815	GARNET	115	1.07	QF	Eastern	Aug NQC	QF/Selfgen
DEVERS_1_QF	25632	TERAWND	115	2.08	QF	Eastern	Aug NQC	QF/Selfgen
DEVERS_1_QF	25633	CAPWIND	115	0.40	QF	Eastern	Aug NQC	QF/Selfgen
DEVERS_1_QF	25634	BUCKWIND	115	1.22	QF	Eastern	Aug NQC	QF/Selfgen
DEVERS_1_QF	25637	TRANWIND	115	4.72	QF	Eastern	Aug NQC	QF/Selfgen
DEVERS_1_QF	25639	SEAWIND	115	1.42	QF	Eastern	Aug NQC	QF/Selfgen
DEVERS_1_QF	25640	PANAERO	115	1.27	QF	Eastern	Aug NQC	QF/Selfgen
DEVERS_1_QF	25636	RENWIND	115	0.19	W1	Eastern	Aug NQC	QF/Selfgen
DMDVLY_1_UNITS	25425	ESRP P2	6.9	21.00		Eastern	Not modeled	QF/Selfgen
DREWS_6_PL1X4				36.00		Eastern	Not modeled Aug NQC	Market
DVLCYN_1_UNITS	25648	DVLCYN1G	13.8	50.35	1	Eastern	Aug NQC	MUNI
DVLCYN_1_UNITS	25649	DVLCYN2G	13.8	50.35	2	Eastern	Aug NQC	MUNI
DVLCYN_1_UNITS	25603	DVLCYN3G	13.8	67.15	3	Eastern	Aug NQC	MUNI
DVLCYN_1_UNITS	25604	DVLCYN4G	13.8	67.15	4	Eastern	Aug NQC	MUNI
ELLIS_2_QF	24197	ELLIS	66	0.11		Western, Ellis	Not modeled Aug NQC	QF/Selfgen
ELSEGN_7_UNIT 3	24047	ELSEG3 G	18	335.00	3	Western, El Nido		Market
ELSEGN_7_UNIT 4	24048	ELSEG4 G	18	335.00	4	Western, El Nido		Market
ETIWND_2_FONTNA	24055	ETIWANDA	66	0.67		Eastern	Not modeled Aug NQC	QF/Selfgen
ETIWND_2_QF	24055	ETIWANDA	66	15.11		Eastern	Not modeled Aug NQC	QF/Selfgen
ETIWND_6_GRPLND	28305	ETWPKGEN	13.8	42.53	1	Eastern		Market
ETIWND_6_MWDETI	25422	ETI MWDG	13.8	15.56	1	Eastern	Aug NQC	Market
ETIWND_7_MIDVLY	24055	ETIWANDA	66	1.58		Eastern	Not modeled Aug NQC	QF/Selfgen
ETIWND_7_UNIT 3	24052	MTNVIST3	18	320.00	3	Eastern		Market
ETIWND_7_UNIT 4	24053	MTNVIST4	18	320.00	4	Eastern		Market
GARNET_1_UNITS	24815	GARNET	115	0.57	G1	Eastern	Aug NQC	QF/Selfgen
GARNET_1_UNITS	24815	GARNET	115	0.20	G2	Eastern	Aug NQC	QF/Selfgen
GARNET_1_UNITS	24815	GARNET	115	0.41	G3	Eastern	Aug NQC	QF/Selfgen
GARNET_1_UNITS	24815	GARNET	115	0.20	PC	Eastern	Aug NQC	QF/Selfgen
GARNET_1_WIND	24815	GARNET	115	0.66	W2	Eastern	Aug NQC	Wind
GARNET_1_WIND	24815	GARNET	115	0.66	W3	Eastern	Aug NQC	Wind
GLNARM_7_UNIT 1	28005	PASADNA1	13.8	22.30	1	Western		MUNI
GLNARM_7_UNIT 2	28006	PASADNA2	13.8	22.30	1	Western		MUNI
GLNARM_7_UNIT 3	28005	PASADNA1	13.8	44.83		Western	Not modeled	MUNI
GLNARM_7_UNIT 4	28006	PASADNA2	13.8	42.42		Western	Not modeled	MUNI
HARBGN_7_UNITS	24062	HARBOR G	13.8	76.28	1	Western		Market
HARBGN_7_UNITS	24062	HARBOR G	13.8	11.86	HP	Western		Market
HARBGN_7_UNITS	25510	HARBORG4	4.16	11.86	LP	Western		Market
HINSON_6_CARBGN	24020	CARBOGEN	13.8	22.67	1	Western	Aug NQC	Market
HINSON_6_LBECH1	24078	LBEACH1G	13.8	65.00	1	Western		Market
HINSON_6_LBECH2	24170	LBEACH2G	13.8	65.00	2	Western		Market
HINSON_6_LBECH3	24171	LBEACH3G	13.8	65.00	3	Western		Market
HINSON_6_LBECH4	24172	LBEACH4G	13.8	65.00	4	Western		Market
HINSON_6_SERRGN	24139	SERRFGEN	13.8	27.67	1	Western	Aug NQC	QF/Selfgen
HNTGBH_7_UNIT 1	24066	HUNT1 G	13.8	225.75	1	Western, Ellis		Market
HNTGBH_7_UNIT 2	24067	HUNT2 G	13.8	225.80	2	Western, Ellis		Market
HNTGBH_7_UNIT 3	24167	HUNT3 G	13.8	225.00	3	Western, Ellis		Market
HNTGBH_7_UNIT 4	24168	HUNT4 G	13.8	227.00	4	Western, Ellis		Market

INDIGO_1_UNIT 1	28190	WINTECX2	13.8	42.00	1	Eastern		Market
INDIGO_1_UNIT 2	28191	WINTECX1	13.8	42.00	1	Eastern		Market
INDIGO_1_UNIT 3	28180	WINTEC8	13.8	42.00	1	Eastern		Market
INLDEM_5_UNIT 1	28041	IEEC-G1	19.5	335.00	1	Eastern	Aug NQC	Market
INLDEM_5_UNIT 2	28042	IEEC-G2	19.5	335.00	1	Eastern	Aug NQC	Market
JOHANN_6_QFA1	24072	JOHANNA	230	0.00		Western, Ellis	Not modeled Aug NQC	QF/Selfgen
LACIEN_2_VENICE	24208	LCIENEGA	66	4.39		Western	Not modeled Aug NQC	QF/Selfgen
LAFRES_6_QF	24073	LA FRESA	66	2.89		Western, El Nido	Not modeled Aug NQC	QF/Selfgen
LAGBEL_6_QF	24075	LAGUBELL	66	10.90		Western	Not modeled Aug NQC	QF/Selfgen
LGHTHP_6_ICEGEN	24070	ICEGEN	13.8	45.72	1	Western	Aug NQC	QF/Selfgen
LGHTHP_6_QF	24083	LITEHIPE	66	0.95		Western	Not modeled Aug NQC	QF/Selfgen
MESAS_2_QF	24209	MESA CAL	66	1.15		Western	Not modeled Aug NQC	QF/Selfgen
MIRLOM_2_CORONA				2.12		Eastern	Not modeled Aug NQC	QF/Selfgen
MIRLOM_2_TEMESC				2.41		Eastern	Not modeled Aug NQC	QF/Selfgen
MIRLOM_6_DELGEN	24030	DELGEN	13.8	32.04	1	Eastern	Aug NQC	QF/Selfgen
MIRLOM_6_PEAKER	28307	MRLPKGEN	13.8	43.18	1	Eastern		Market
MIRLOM_7_MWDLKM	24210	MIRALOMA	66	3.90		Eastern	Not modeled Aug NQC	MUNI
MOJAVE_1_SIPHON	25657	MJVSPHN1	13.8	4.67	1	Eastern	Aug NQC	Market
MOJAVE_1_SIPHON	25657	MJVSPHN1	13.8	4.67	2	Eastern	Aug NQC	Market
MOJAVE_1_SIPHON	25657	MJVSPHN1	13.8	4.67	3	Eastern	Aug NQC	Market
MTWIND_1_UNIT 1				5.13		Eastern	Not modeled Aug NQC	Wind
MTWIND_1_UNIT 2				2.10		Eastern	Not modeled Aug NQC	Wind
MTWIND_1_UNIT 3				2.07		Eastern	Not modeled Aug NQC	Wind
OLINDA_2_COYCRK	24211	OLINDA	66	3.13		Western	Not modeled	QF/Selfgen
OLINDA_2_QF	24211	OLINDA	66	1.02	1	Western	Aug NQC	QF/Selfgen
OLINDA_7_LNDFIL	24201	BARRE	66	4.50		Western	Not modeled Aug NQC	QF/Selfgen
PADUA_2_ONTARO	24111	PADUA	66	0.63		Eastern	Not modeled Aug NQC	QF/Selfgen
PADUA_6_MWDSDM	24111	PADUA	66	5.60		Eastern	Not modeled Aug NQC	MUNI
PADUA_6_QF	24111	PADUA	66	2.18		Eastern	Not modeled Aug NQC	QF/Selfgen
PADUA_7_SDIMAS	24111	PADUA	66	1.05		Eastern	Not modeled Aug NQC	QF/Selfgen
PWEST_1_UNIT				0.22		Western	Not modeled Aug NQC	Market
REDOND_7_UNIT 5	24121	REDON5 G	18	178.87	5	Western		Market
REDOND_7_UNIT 6	24122	REDON6 G	18	175.00	6	Western		Market
REDOND_7_UNIT 7	24123	REDON7 G	20	505.96	7	Western		Market
REDOND_7_UNIT 8	24124	REDON8 G	20	495.90	8	Western		Market
RHONDO_2_QF	24213	RIOHONDO	66	1.62		Western	Not modeled Aug NQC	QF/Selfgen
RHONDO_6_PUENTE	24213	RIOHONDO	66	0.00		Western	Not modeled Aug NQC	Market
RVSIDE_6_RERCU1	24242	RERC1G	13.8	48.35	1	Eastern		MUNI

RVSIDE_6_RERCU2	24243	RERC2G	13.8	48.50	1	Eastern		MUNI
RVSIDE_6_SPRING	24244	SPRINGEN	13.8	36.00	1	Eastern		Market
SANTGO_6_COYOTE	24133	SANTIAGO	66	4.22	1	Western, Ellis	Aug NQC	Market
SBERDO_2_PSP3	24921	MNTV-CT1	18	129.71	1	Eastern		Market
SBERDO_2_PSP3	24922	MNTV-CT2	18	129.71	1	Eastern		Market
SBERDO_2_PSP3	24923	MNTV-ST1	18	225.08	1	Eastern		Market
SBERDO_2_PSP4	24924	MNTV-CT3	18	129.71	1	Eastern		Market
SBERDO_2_PSP4	24925	MNTV-CT4	18	129.71	1	Eastern		Market
SBERDO_2_PSP4	24926	MNTV-ST2	18	225.08	1	Eastern		Market
SBERDO_2_QF	24214	SANBRDNO	66	0.17		Eastern	Not modeled Aug NQC	QF/Selfgen
SBERDO_2_SNTANA	24214	SANBRDNO	66	0.05		Eastern	Not modeled Aug NQC	QF/Selfgen
SBERDO_6_MILLCK	24214	SANBRDNO	66	1.08		Eastern	Not modeled Aug NQC	QF/Selfgen
SONGS_7_UNIT 2	24129	S.ONOFR2	22	1122.00	2	Western		Nuclear
SONGS_7_UNIT 3	24130	S.ONOFR3	22	1124.00	3	Western		Nuclear
TIFFNY_1_DILLON				6.37		Western	Not modeled Aug NQC	Wind
VALLEY_5_PERRIS	24160	VALLEYSC	115	7.94		Eastern	Not modeled Aug NQC	QF/Selfgen
VALLEY_5_REDMTN	24160	VALLEYSC	115	0.16		Eastern	Not modeled Aug NQC	QF/Selfgen
VALLEY_7_BADLND	24160	VALLEYSC	115	0.38		Eastern	Not modeled Aug NQC	Market
VALLEY_7_UNITA1	24160	VALLEYSC	115	1.13		Eastern	Not modeled Aug NQC	Market
VERNON_6_GONZL1				5.75		Western	Not modeled	MUNI
VERNON_6_GONZL2				5.75		Western	Not modeled	MUNI
VERNON_6_MALBRG	24239	MALBRG1G	13.8	42.37	C1	Western		MUNI
VERNON_6_MALBRG	24240	MALBRG2G	13.8	42.37	C2	Western		MUNI
VERNON_6_MALBRG	24241	MALBRG3G	13.8	49.26	S3	Western		MUNI
VILLPK_2_VALLYV	24216	VILLA PK	66	4.10		Western	Not modeled Aug NQC	QF/Selfgen
VILLPK_6_MWDYOR	24216	VILLA PK	66	4.30		Western	Not modeled Aug NQC	MUNI
VISTA_6_QF	24902	VSTA	66	0.26	1	Eastern	Aug NQC	QF/Selfgen
WALNUT_6_HILLGEN	24063	HILLGEN	13.8	46.68	1	Western	Aug NQC	QF/Selfgen
WALNUT_7_WCOVCT	24157	WALNUT	66	3.43		Western	Not modeled Aug NQC	Market
WALNUT_7_WCOVST	24157	WALNUT	66	2.98		Western	Not modeled Aug NQC	Market
WHTWTR_1_WINDA1	28061	WHITEWTR	33	6.61	1	Eastern	Aug NQC	Wind
ARCOGN_2_UNITS	24018	BRIGEN	13.8	0.00	1	Western	No NQC - hist. data	Market
HINSON_6_QF	24064	HINSON	66	0.00	1	Western	No NQC - hist. data	QF/Selfgen
INLAND_6_UNIT	24071	INLAND	13.8	30.30	1	Eastern	No NQC - hist. data	QF/Selfgen
MOBGEN_6_UNIT 1	24094	MOBGEN	13.8	20.20	1	Western, El Nido	No NQC - hist. data	QF/Selfgen
NA	24325	ORCOGEN	13.8	0.00	1	Western, Ellis	No NQC - hist. data	QF/Selfgen
NA	24327	THUMSGEN	13.8	0.00	1	Western	No NQC - hist. data	QF/Selfgen
NA	24330	OUTFALL1	13.8	0.00	1	Western, El Nido	No NQC - hist. data	QF/Selfgen
NA	24331	OUTFALL2	13.8	0.00	1	Western, El Nido	No NQC -	QF/Selfgen

							hist. data	
NA	24337	VENICE	13.8	0.00	1	Western, El Nido	No NQC - hist. data	QF/Selfgen
NA	24341	COYGEN	13.8	18.00	1	Western, Ellis	No NQC - hist. data	QF/Selfgen
NA	24342	FEDGEN	13.8	0.00	1	Western	No NQC - hist. data	QF/Selfgen
NA	25301	CLTNDREW	13.8	47.20	1	Eastern	No NQC - Pmax	QF/Selfgen
NA	25302	CLTNCTRY	13.8	47.20	1	Eastern	No NQC - Pmax	QF/Selfgen
NA	25303	CLTNAGUA	13.8	45.00	1	Eastern	No NQC - Pmax	QF/Selfgen
NA	29338	CLEARGEN	13.8	0.00	1	Eastern	No NQC - hist. data	QF/Selfgen
NA	29339	DELGEN	13.8	0.00	1	Eastern	No NQC - hist. data	QF/Selfgen
NA	24324	SANIGEN	13.8	6.80	D1	Eastern	No NQC - hist. data	QF/Selfgen
NA	24332	PALOGEN	13.8	3.20	D1	Western, El Nido	No NQC - hist. data	QF/Selfgen
RVSIDE_2_RERCU3	24299	RERC2G3	13.8	50.00	1	Eastern	No NQC - Pmax	MUNI
RVSIDE_2_RERCU4	24300	RERC2G4	13.8	50.00	1	Eastern	No NQC - Pmax	MUNI

Major new projects modeled:

1. 2 small new resources have been modeled

Critical Contingency Analysis Summary

LA Basin Overall:

The most critical contingency for LA Basin is the loss of one Songs unit followed by Palo Verde-Devers 500 kV line, which could exceed the approved 6400 MW rating for the South of Lugo path. This limiting contingency establishes a LCR of 10,865 MW in 2012 (includes 850 MW of QF, 33 MW of Wind, 900 MW of Muni and 2246 MW of Nuclear generation) as the minimum generation capacity necessary for reliable load serving capability within this area.

Effectiveness factors:

The following table has units that have at least 5% effectiveness to the above-mentioned South of Lugo constraint within the LA Basin area:

Gen Bus	Gen Name	Gen ID	MW Eff. Fact (%)
24052	MTNVIST3	3	34

24053	MTNVIST4	4	34
24071	INLAND	1	33
25422	ETI MWDG	1	33
29305	ETWPKGEN	1	33
24905	RVCANAL1	R1	26
24906	RVCANAL2	R2	26
24907	RVCANAL3	R3	26
24908	RVCANAL4	R4	26
24921	MNTV-CT1	1	26
24922	MNTV-CT2	1	26
24923	MNTV-ST1	1	26
24924	MNTV-CT3	1	26
24925	MNTV-CT4	1	26
24926	MNTV-ST2	1	26
24242	RERC1G	1	26
24243	RERC2G	1	26
24242	RERC1G	1	26
24243	RERC2G	1	26
24244	SPRINGEN	1	26
25301	CLTNDREW	1	26
25302	CLTNCTRY	1	26
25303	CLTNAGUA	1	26
25603	DVLCYN3G	3	25
25604	DVLCYN4G	4	25
25648	DVLCYN1G	1	24
25649	DVLCYN2G	2	24
29041	IEEC-G1	1	24
29042	IEEC-G2	2	24
25203	ANAHEIMG	1	22
25632	TERAWND	QF	22
25634	BUCKWND	QF	22
25635	ALTWIND	Q1	22
25635	ALTWIND	Q2	22
25637	TRANWND	QF	22
25639	SEAWIND	QF	22
25640	PANAERO	QF	22
25645	VENWIND	EU	22
25645	VENWIND	Q2	22
25645	VENWIND	Q1	22
25646	SANWIND	Q2	22
29190	WINTECX2	1	22
29191	WINTECX1	1	22
29180	WINTEC8	1	22

24815	GARNET	QF	22
24815	GARNET	W3	22
24815	GARNET	W2	22
29023	WINTEC4	1	22
29060	SEAWEST	S1	22
29060	SEAWEST	S3	22
29060	SEAWEST	S2	22
29260	ALTAMSA4	1	22
29290	CABAZON	1	22
29021	WINTEC6	1	22
25657	MJVSPHN1	1	22
25658	MJVSPHN2	2	22
25659	MJVSPHN3	3	22
24030	DELGEN	1	21
25633	CAPWIND	QF	21
29061	WHITEWTR	1	21
24026	CIMGEN	D1	21
24140	SIMPSON	D1	21
29309	BARPKGEN	1	20
29307	MRLPKGEN	1	19
29338	CLEARGEN	1	19
29339	DELGEN	1	19
24066	HUNT1 G	1	18
24067	HUNT2 G	2	18
24167	HUNT3 G	3	18
24168	HUNT4 G	4	18
24129	S.ONOFR2	2	18
24130	S.ONOFR3	3	18
24133	SANTIAGO	1	18
24325	ORCOGEN	1	18
24341	COYGEN	1	18
24001	ALAMT1 G	1	17
24002	ALAMT2 G	2	17
24003	ALAMT3 G	3	17
24004	ALAMT4 G	4	17
24005	ALAMT5 G	5	17
24161	ALAMT6 G	6	17
24162	ALAMT7 G	R7	17
24063	HILLGEN	D1	16
29209	BLY1ST1	1	15
29207	BLY1CT1	1	15
29208	BLY1CT2	1	15
29953	SIGGEN	D1	15

24018	BRIGEN	1	14
24020	CARBGEN1	1	14
24064	HINSON	1	14
24070	ICEGEN	D1	14
24170	LBEACH12	2	14
24171	LBEACH34	3	14
24079	LBEACH7G	7	14
24080	LBEACH8G	8	14
24081	LBEACH9G	9	14
24062	HARBOR G	1	14
25510	HARBORG4	LP	14
24062	HARBOR G	HP	14
29308	CTRPKGEN	1	14
24139	SERRFGEN	D1	14
24170	LBEACH12	1	14
24171	LBEACH34	4	14
24173	LBEACH5G	R5	14
24174	LBEACH6G	R6	14
24327	THUMSGEN	1	14
24328	CARBGEN2	1	14
24337	VENICE	1	14
24011	ARCO 1G	1	13
24012	ARCO 2G	2	13
24013	ARCO 3G	3	13
24014	ARCO 4G	4	13
24163	ARCO 5G	5	13
24164	ARCO 6G	6	13
24022	CHEVGEN1	1	13
24023	CHEVGEN2	2	13
24047	ELSEG3 G	3	13
24048	ELSEG4 G	4	13
24094	MOBGEN1	1	13
24121	REDON5 G	5	13
24122	REDON6 G	6	13
24123	REDON7 G	7	13
24124	REDON8 G	8	13
24329	MOBGEN2	1	13
24330	OUTFALL1	1	13
24331	OUTFALL2	1	13
24332	PALOGEN	D1	13
24333	REDON1 G	R1	13
24334	REDON2 G	R2	13
24335	REDON3 G	R3	13

24336	REDON4 G	R4	13
24241	MALBRG3G	S3	11
24240	MALBRG2G	C2	11
24239	MALBRG1G	C1	11
29951	REFUSE	D1	11
24342	FEDGEN	1	11
29007	BRODWYSC	1	9
29005	PASADNA1	1	8
29006	PASADNA2	1	8

Western Sub-Area:

The most critical contingency for the Western sub-area is the loss of Serrano-Villa Park #1 or #2 230 kV line followed by the loss of the Serrano-Lewis 230 kV line or vice versa, which would result in thermal overload of the remaining Serrano-Villa Park 230 kV line. This limiting contingency establishes a LCR of 5785 MW (includes 559 MW of QF, 6 MW of Wind, 387 MW of Muni and 2246 MW of nuclear generation) in 2012 as the generation capacity necessary for reliable load serving capability within this sub-area.

Effectiveness factors:

There are numerous (about 40) other combinations of contingencies in the area that could overload a significant number of 230 kV lines in this sub-area and have slightly less LCR need. As such, anyone of them (combination of contingencies) could become binding for any given set of procured resources. As a result, effectiveness factors are not given since they would most likely not facilitate more informed procurement.

Ellis sub-area

The most critical contingency for the Ellis sub-area is the loss of the Barre to Ellis 230 kV line followed by the loss of the Santiago to S.Onofre #1 and #2 230 kV lines, which would cause voltage collapse. This limiting contingency establishes a LCR of 474 MW in 2012 (which includes 18 MW of QF generation) as the minimum capacity necessary for reliable load serving capability within this sub-area.

Effectiveness factors:

The generators inside the sub-area have the same effectiveness factors.

El Nido sub-area

There are two most critical contingencies for the El Nido sub-area that cause the same LCR need:

1. The loss of the La Fresa-Redondo #1 and #2 230 kV lines which could overload La Fresa-Hinson 230 kV line.
2. The loss of the La Fresa – Hinson 230 kV line followed by the loss of the La Fresa – Redondo #1 and #2 230 kV lines, which would cause voltage collapse.

These two limiting contingencies establish a LCR of 362 MW in 2012 (which includes 27 MW of QF generation) as the minimum capacity necessary for reliable load serving capability within this sub-area.

Effectiveness factors:

The generators inside the sub-area have the same effectiveness factors.

Changes compared to last year's results:

Overall the load forecast went up by 45 MW resulting in an increase in LCR by 276 MW. The higher LCR increase is due in part to load allocation change, between LA Basin, Big Creek Ventura and the rest of SCE system based on new CEC load forecast and the decrease in LCR needs for the San Diego area due to the new Sunrise Power Link.

LA Basin Overall Requirements:

2012	QF/Wind (MW)	Muni (MW)	Nuclear (MW)	Market (MW)	Max. Qualifying Capacity (MW)
Available generation	883	900	2246	8054	12083

2012	Existing Generation Capacity Needed (MW)	Deficiency (MW)	Total MW LCR Need
Category B (Single)[23]	10,865	0	10,865
Category C (Multiple)[24]	10,865	0	10,865

[23] A single contingency means that the system will be able the survive the loss of a single element, however the operators will not have any means (other then load drop) in order to bring the system within a safe operating zone and get prepared for the next contingency as required by MORC.

9. Big Creek/Ventura Area

Area Definition

The transmission tie lines into the Big Creek/Ventura Area are:

1) Vincent-Antelope #1 230 kV Line
2) Vincent-Antelope #2 230 kV Line
3) Sylmar-Pardee #1 230 kV Line
4) Sylmar-Pardee #2 230 kV Line
5) Eagle Rock-Pardee #1 230 kV Line
6) Vincent-Pardee 230 kV Line
7) Vincent-Santa Clara 230 kV Line

These sub-stations form the boundary surrounding the Big Creek/Ventura area:

1) Vincent is out Antelope is in
2) Vincent is out Antelope is in
3) Sylmar is out Pardee is in
4) Sylmar is out Pardee is in
5) Eagle Rock is out Pardee is in
6) Vincent is out Pardee is in
7) Vincent is out Santa Clara is in

Total 2012 busload within the defined area is 4260 MW with 78 MW of losses and 355 MW of pumps resulting in total load + losses + pumps of 4693 MW.

Total units and qualifying capacity available in the Big Creek/Ventura area:

MKT/SCHED RESOURCE ID	BUS #	BUS NAME	kV	NQC	UNIT ID	LCR SUB-AREA NAME	NQC Comments	CAISO Tag
ALAMO_6_UNIT	25653	ALAMO SC	13.8	16.00	1	Big Creek	Aug NQC	Market
ANTLPE_2_QF	24457	ARBWIND	66	2.90	1	Big Creek	Aug NQC	Wind
ANTLPE_2_QF	24458	ENCANWND	66	15.03	1	Big Creek	Aug NQC	Wind
ANTLPE_2_QF	24459	FLOWIND	66	5.43	1	Big Creek	Aug NQC	Wind
ANTLPE_2_QF	24460	DUTCHWND	66	1.86	1	Big Creek	Aug NQC	Wind

[24] Multiple contingencies means that the system will be able the survive the loss of a single element, and the operators will have enough generation (other operating procedures) in order to bring the system within a safe operating zone and get prepared for the next contingency as required by MORC.

ANTLPE_2_QF	24465	MORWIND	66	7.45	1	Big Creek	Aug NQC	Wind
ANTLPE_2_QF	24491	OAKWIND	66	2.40	1	Big Creek	Aug NQC	Wind
ANTLPE_2_QF	28501	MIDWIND	12	2.40	1	Big Creek	Aug NQC	Wind
ANTLPE_2_QF	28502	SOUTHWND	12	0.88	1	Big Creek	Aug NQC	Wind
ANTLPE_2_QF	28503	NORTHWND	12	2.58	1	Big Creek	Aug NQC	Wind
ANTLPE_2_QF	28504	ZONDWND1	12	1.76	1	Big Creek	Aug NQC	Wind
ANTLPE_2_QF	28505	ZONDWND2	12	1.70	1	Big Creek	Aug NQC	Wind
ANTLPE_2_QF	28506	BREEZE1	12	0.60	1	Big Creek	Aug NQC	Wind
ANTLPE_2_QF	28507	BREEZE2	12	1.06	1	Big Creek	Aug NQC	Wind
BIGCRK_2_EXESWD	24306	B CRK1-1	7.2	19.38	1	Big Creek, Rector, Vestal	Aug NQC	Market
BIGCRK_2_EXESWD	24308	B CRK2-1	13.8	49.48	1	Big Creek, Rector, Vestal	Aug NQC	Market
BIGCRK_2_EXESWD	24311	B CRK3-1	13.8	34.09	1	Big Creek, Rector, Vestal	Aug NQC	Market
BIGCRK_2_EXESWD	24317	MAMOTH1G	13.8	91.07	1	Big Creek, Rector, Vestal	Aug NQC	Market
BIGCRK_2_EXESWD	24323	PORTAL	4.8	9.35	1	Big Creek, Rector, Vestal	Aug NQC	Market
BIGCRK_2_EXESWD	24306	B CRK1-1	7.2	21.03	2	Big Creek, Rector, Vestal	Aug NQC	Market
BIGCRK_2_EXESWD	24308	B CRK2-1	13.8	50.64	2	Big Creek, Rector, Vestal	Aug NQC	Market
BIGCRK_2_EXESWD	24311	B CRK3-1	13.8	34.09	2	Big Creek, Rector, Vestal	Aug NQC	Market
BIGCRK_2_EXESWD	24318	MAMOTH2G	13.8	91.07	2	Big Creek, Rector, Vestal	Aug NQC	Market
BIGCRK_2_EXESWD	24307	B CRK1-2	13.8	21.03	3	Big Creek, Rector, Vestal	Aug NQC	Market
BIGCRK_2_EXESWD	24309	B CRK2-2	7.2	18.22	3	Big Creek, Rector, Vestal	Aug NQC	Market
BIGCRK_2_EXESWD	24312	B CRK3-2	13.8	34.09	3	Big Creek, Rector, Vestal	Aug NQC	Market
BIGCRK_2_EXESWD	24307	B CRK1-2	13.8	30.39	4	Big Creek, Rector, Vestal	Aug NQC	Market
BIGCRK_2_EXESWD	24309	B CRK2-2	7.2	19.19	4	Big Creek, Rector, Vestal	Aug NQC	Market
BIGCRK_2_EXESWD	24312	B CRK3-2	13.8	39.93	4	Big Creek, Rector, Vestal	Aug NQC	Market
BIGCRK_2_EXESWD	24310	B CRK2-3	7.2	16.55	5	Big Creek, Rector, Vestal	Aug NQC	Market
BIGCRK_2_EXESWD	24313	B CRK3-3	13.8	37.99	5	Big Creek, Rector, Vestal	Aug NQC	Market
BIGCRK_2_EXESWD	24310	B CRK2-3	7.2	18.02	6	Big Creek, Rector, Vestal	Aug NQC	Market
BIGCRK_2_EXESWD	24314	B CRK 4	11.5	49.09	41	Big Creek, Rector, Vestal	Aug NQC	Market
BIGCRK_2_EXESWD	24314	B CRK 4	11.5	49.28	42	Big Creek, Rector, Vestal	Aug NQC	Market
BIGCRK_2_EXESWD	24315	B CRK 8	13.8	23.76	81	Big Creek, Rector, Vestal	Aug NQC	Market
BIGCRK_2_EXESWD	24315	B CRK 8	13.8	42.85	82	Big Creek, Rector, Vestal	Aug NQC	Market
EASTWD_7_UNIT	24319	EASTWOOD	13.8	199.00	1	Big Creek, Rector, Vestal		Market
EDMONS_2_NSPIN	25605	EDMON1AP	14.4	24.11	1	Big Creek	Pumps	MUNI
EDMONS_2_NSPIN	25606	EDMON2AP	14.4	24.11	2	Big Creek	Pumps	MUNI
EDMONS_2_NSPIN	25607	EDMON3AP	14.4	24.11	3	Big Creek	Pumps	MUNI
EDMONS_2_NSPIN	25607	EDMON3AP	14.4	24.11	4	Big Creek	Pumps	MUNI

EDMONS_2_NSPIN	25608	EDMON4AP	14.4	24.11	5	Big Creek	Pumps	MUNI
EDMONS_2_NSPIN	25608	EDMON4AP	14.4	24.11	6	Big Creek	Pumps	MUNI
EDMONS_2_NSPIN	25609	EDMON5AP	14.4	24.11	7	Big Creek	Pumps	MUNI
EDMONS_2_NSPIN	25609	EDMON5AP	14.4	24.11	8	Big Creek	Pumps	MUNI
EDMONS_2_NSPIN	25610	EDMON6AP	14.4	24.11	9	Big Creek	Pumps	MUNI
EDMONS_2_NSPIN	25610	EDMON6AP	14.4	24.11	10	Big Creek	Pumps	MUNI
EDMONS_2_NSPIN	25611	EDMON7AP	14.4	24.10	11	Big Creek	Pumps	MUNI
EDMONS_2_NSPIN	25611	EDMON7AP	14.4	24.10	12	Big Creek	Pumps	MUNI
EDMONS_2_NSPIN	25612	EDMON8AP	14.4	24.10	13	Big Creek	Pumps	MUNI
EDMONS_2_NSPIN	25612	EDMON8AP	14.4	24.10	14	Big Creek	Pumps	MUNI
GOLETA_2_QF	24057	GOLETA	66	0.17		Ventura, S.Clara, Moorpark	Not modeled Aug NQC	QF/Selfgen
GOLETA_6_ELLWOD	28004	ELLWOOD	13.8	54.00	1	Ventura, S.Clara, Moorpark		Market
GOLETA_6_EXGEN	24057	GOLETA	66	0.35		Ventura, S.Clara, Moorpark	Not modeled Aug NQC	QF/Selfgen
GOLETA_6_GAVOTA	24057	GOLETA	66	1.50		Ventura, S.Clara, Moorpark	Not modeled Aug NQC	QF/Selfgen
GOLETA_6_TAJIGS	24057	GOLETA	66	2.77		Ventura, S.Clara, Moorpark	Not modeled Aug NQC	Market
KERRGN_1_UNIT 1	24437	KERNRVR	66	11.75	1	Big Creek	Aug NQC	Market
LEBECS_2_UNITS	28051	PSTRIAG1	18	157.90	G1	Big Creek	Aug NQC	Market
LEBECS_2_UNITS	28052	PSTRIAG2	18	157.90	G2	Big Creek	Aug NQC	Market
LEBECS_2_UNITS	28054	PSTRIAG3	18	157.90	G3	Big Creek	Aug NQC	Market
LEBECS_2_UNITS	28053	PSTRIAS1	18	162.40	S1	Big Creek	Aug NQC	Market
LEBECS_2_UNITS	28055	PSTRIAS2	18	78.90	S2	Big Creek	Aug NQC	Market
MNDALY_7_UNIT 1	24089	MANDLY1G	13.8	215.00	1	Ventura, Moorpark		Market
MNDALY_7_UNIT 2	24090	MANDLY2G	13.8	215.29	2	Ventura, Moorpark		Market
MNDALY_7_UNIT 3	24222	MANDLY3G	16	130.00	3	Ventura, S.Clara, Moorpark		Market
MONLTH_6_BOREL	24456	BOREL	66	8.75	1	Big Creek	Aug NQC	QF/Selfgen
MOORPK_2_CALABS	24099	MOORPARK	230	6.96		Ventura, Moorpark	Not modeled	Market
MOORPK_6_QF	24098	MOORPARK	66	26.61		Ventura, Moorpark	Not modeled Aug NQC	QF/Selfgen
MOORPK_7_UNITA1	24098	MOORPARK	66	1.10		Ventura, Moorpark	Not modeled Aug NQC	QF/Selfgen
OMAR_2_UNITS	24102	OMAR 1G	13.8	77.25	1	Big Creek		QF/Selfgen
OMAR_2_UNITS	24103	OMAR 2G	13.8	77.25	2	Big Creek		QF/Selfgen
OMAR_2_UNITS	24104	OMAR 3G	13.8	77.25	3	Big Creek		QF/Selfgen
OMAR_2_UNITS	24105	OMAR 4G	13.8	77.25	4	Big Creek		QF/Selfgen
ORMOND_7_UNIT 1	24107	ORMOND1G	26	741.27	1	Ventura, Moorpark		Market
ORMOND_7_UNIT 2	24108	ORMOND2G	26	775.00	2	Ventura, Moorpark		Market
OSO_6_NSPIN	25614	OSO A P	13.2	2.30	1	Big Creek	Pumps	MUNI
OSO_6_NSPIN	25614	OSO A P	13.2	2.30	2	Big Creek	Pumps	MUNI
OSO_6_NSPIN	25614	OSO A P	13.2	2.30	3	Big Creek	Pumps	MUNI

OSO_6_NSPIN	25614	OSO A P	13.2	2.30	4	Big Creek	Pumps	MUNI
OSO_6_NSPIN	25615	OSO B P	13.2	2.30	5	Big Creek	Pumps	MUNI
OSO_6_NSPIN	25615	OSO B P	13.2	2.30	6	Big Creek	Pumps	MUNI
OSO_6_NSPIN	25615	OSO B P	13.2	2.30	7	Big Creek	Pumps	MUNI
OSO_6_NSPIN	25615	OSO B P	13.2	2.30	8	Big Creek	Pumps	MUNI
PANDOL_6_UNIT	24113	PANDOL	13.8	21.61	1	Big Creek, Vestal	Aug NQC	QF/Selfgen
PANDOL_6_UNIT	24113	PANDOL	13.8	17.61	2	Big Creek, Vestal	Aug NQC	QF/Selfgen
RECTOR_2_KAWEAH	24212	RECTOR	66	0.30		Big Creek, Rector, Vestal	Not modeled Aug NQC	Market
RECTOR_2_KAWH 1	24212	RECTOR	66	0.41		Big Creek, Rector, Vestal	Not modeled Aug NQC	Market
RECTOR_2_QF	24212	RECTOR	66	2.34		Big Creek, Rector, Vestal	Not modeled Aug NQC	QF/Selfgen
RECTOR_7_TULARE	24212	RECTOR	66	1.60		Big Creek, Rector, Vestal	Not modeled	QF/Selfgen
SAUGUS_6_MWDFTH	24135	SAUGUS	66	6.40		Big Creek	Not modeled Aug NQC	MUNI
SAUGUS_6_PTCHGN	24118	PITCHGEN	13.8	20.31	1	Big Creek	Aug NQC	MUNI
SAUGUS_6_QF	24135	SAUGUS	66	1.17		Big Creek	Not modeled Aug NQC	QF/Selfgen
SAUGUS_7_LOPEZ	24135	SAUGUS	66	5.37		Big Creek	Not modeled Aug NQC	QF/Selfgen
SNCLRA_6_OXGEN	24110	OXGEN	13.8	32.53	1	Ventura, S.Clara, Moorpark	Aug NQC	QF/Selfgen
SNCLRA_6_PROCGN	24119	PROCGEN	13.8	44.65	1	Ventura, S.Clara, Moorpark	Aug NQC	Market
SNCLRA_6_QF	24127	S.CLARA	66	1.73	1	Ventura, S.Clara, Moorpark	Aug NQC	QF/Selfgen
SNCLRA_6_WILLMT	24159	WILLAMET	13.8	12.64	1	Ventura, S.Clara, Moorpark	Aug NQC	QF/Selfgen
SPRGVL_2_QF	24215	SPRINGVL	66	0.19		Big Creek, Rector, Vestal	Not modeled Aug NQC	QF/Selfgen
SPRGVL_2_TULE	24215	SPRINGVL	66	0.23		Big Creek, Rector, Vestal	Not modeled Aug NQC	Market
SPRGVL_2_TULESC	24215	SPRINGVL	66	0.42		Big Creek, Rector, Vestal	Not modeled Aug NQC	Market
SYCAMR_2_UNITS	24143	SYCCYN1G	13.8	64.47	1	Big Creek	Aug NQC	QF/Selfgen
SYCAMR_2_UNITS	24144	SYCCYN2G	13.8	64.47	2	Big Creek	Aug NQC	QF/Selfgen
SYCAMR_2_UNITS	24145	SYCCYN3G	13.8	64.47	3	Big Creek	Aug NQC	QF/Selfgen
SYCAMR_2_UNITS	24146	SYCCYN4G	13.8	64.46	4	Big Creek	Aug NQC	QF/Selfgen
TENGEN_2_PL1X2	24148	TENNGEN1	13.8	18.39	1	Big Creek	Aug NQC	Market
TENGEN_2_PL1X2	24149	TENNGEN2	13.8	18.38	2	Big Creek	Aug NQC	Market
VESTAL_2_KERN	24152	VESTAL	66	2.02	1	Big Creek, Vestal	Aug NQC	QF/Selfgen
VESTAL_6_QF	24152	VESTAL	66	2.17		Big Creek, Vestal	Not modeled Aug NQC	QF/Selfgen
VESTAL_6_ULTRGN	24150	ULTRAGEN	13.8	34.76	1	Big Creek, Vestal	Aug NQC	QF/Selfgen
VESTAL_6_WDFIRE	28008	LAKEGEN	13.8	5.68	1	Big Creek, Vestal	Aug NQC	QF/Selfgen
WARNE_2_UNIT	25651	WARNE1	13.8	38.00	1	Big Creek	Aug NQC	Market
WARNE_2_UNIT	25652	WARNE2	13.8	38.00	1	Big Creek	Aug NQC	Market

NA	24340	CHARMIN	13.8	15.20	1	Ventura, S.Clara, Moorpark	No NQC - hist. data	QF/Selfgen
NA	24372	KR 3-1	13.8	0.00	1	Big Creek, Vestal	No NQC - hist. data	QF/Selfgen
NA	24373	KR 3-2	13.8	0.00	1	Big Creek, Vestal	No NQC - hist. data	QF/Selfgen
NA	24422	PALMDALE	66	0.00	1	Big Creek	No NQC - hist. data	Market
NA	24436	GOLDTOWN	66	0.00	1	Big Creek	No NQC - hist. data	Market
NA	24362	Exgen2	13.8	0.00	G1	Ventura, S.Clara, Moorpark	No NQC - hist. data	QF/Selfgen
NA	24326	Exgen1	13.8	0.00	S1	Ventura, S.Clara, Moorpark	No NQC - hist. data	QF/Selfgen

Major new projects modeled: None

Critical Contingency Analysis Summary

Big Creek/Ventura overall:

The most critical contingency is the loss of Sylmar-Pardee #1 (or # 2) line followed by Ormond Beach Unit #2, which could thermally overload the remaining Sylmar-Pardee 230 kV line. This limiting contingency establishes a LCR of 3093 MW in 2012 (includes 762 MW of QF, 383 MW of Muni and 46 MW of Wind generation) as the minimum generation capacity necessary for reliable load serving capability within this area.

The second most critical contingency is the loss of the Lugo-Victorville 500 kV followed by Sylmar-Pardee #1 or #2 230 kV line, which could thermally overload the remaining Sylmar-Pardee 230 kV line. This limiting contingency establishes a LCR of 3009 MW in 2012 (includes 762 MW of QF, 383 MW of Muni and 46 MW of Wind generation).

Effectiveness factors:

The following table has units that have at least 5% effectiveness to any one of the Sylmar-Pardee 230 kV lines after the loss of the Lugo-Victorville 500 kV followed by one of the other Sylmar-Pardee 230 kV line in this area:

Gen Bus	Gen Name	Gen ID	MW Eff. Fctr. (%)
24009	APPGEN1G	1	29
24010	APPGEN2G	2	29

24107	ORMOND1G	1	29
24108	ORMOND2G	2	29
24118	PITCHGEN	1	28
24148	TENNGEN1	1	28
24149	TENNGEN2	2	28
24089	MANDLY1G	1	27
24090	MANDLY2G	2	27
24110	OXGEN	1	27
24119	PROCGEN	1	27
24159	WILLAMET	1	27
25651	WARNE1	1	27
25652	WARNE2	1	27
28004	ELLWOOD	1	27
24361	EXGEN1	1	27
24362	EXGEN2	2	27
28051	PSTRIAG1	G1	26
25606	EDMON2AP	2	26
25607	EDMON3AP	3	26
25607	EDMON3AP	4	26
25608	EDMON4AP	5	26
25608	EDMON4AP	6	26
25609	EDMON5AP	7	26
25609	EDMON5AP	8	26
25610	EDMON6AP	9	26
25610	EDMON6AP	10	26
25611	EDMON7AP	11	26
25611	EDMON7AP	12	26
25612	EDMON8AP	13	26
25612	EDMON8AP	14	26
28054	PSTRIAG3	G3	25
25615	OSO B P	7	25
25615	OSO B P	8	25
28952	CAMGEN	13.8	25
24127	S.CLARA	1	25
24340	CHARMIN	1	25
28055	PSTRIAS2	S2	24
28053	PSTRIAS1	S1	24
28052	PSTRIAG2	G2	24
25605	EDMON1AP	1	24
24143	SYCCYN1G	1	24
24144	SYCCYN2G	2	24
24145	SYCCYN3G	3	24
24146	SYCCYN4G	4	24
24102	OMAR 1G	1	23
24103	OMAR 2G	2	23
24104	OMAR 3G	3	23
24105	OMAR 4G	4	23
25614	OSO A P	1	23
25614	OSO A P	2	23
25653	ALAMO SC	1	23

24222	MANDLY3G	3	20
28008	LAKEGEN	1	20
24150	ULTRAGEN	1	20
24152	VESTAL	1	20
24372	KR 3-1	1	45
24373	KR 3-2	2	45
24370	KAWGEN	1	45
24319	EASTWOOD	1	20
24306	B CRK1-1	1	20
24306	B CRK1-1	2	20
24307	B CRK1-2	3	20
24307	B CRK1-2	4	20
24308	B CRK2-1	1	20
24308	B CRK2-1	2	20
24309	B CRK2-2	3	20
24309	B CRK2-2	4	20
24310	B CRK2-3	5	20
24310	B CRK2-3	6	20
24311	B CRK3-1	1	20
24311	B CRK3-1	2	20
24312	B CRK3-2	3	20
24312	B CRK3-2	4	20
24313	B CRK3-3	5	20
24314	B CRK 4	41	20
24314	B CRK 4	42	20
24315	B CRK 8	81	20
24315	B CRK 8	82	20
24317	MAMOTH1G	1	20
24318	MAMOTH2G	2	20
24113	PANDOL	1	19
24113	PANDOL	2	19
24437	KERNRVR	1	18
24459	FLOWIND	1	14
24436	GOLDTOWN	1	14
28501	MIDWIND	1	14
24457	ARBWIND	1	13
24456	BOREL	1	12
24458	ENCANWND	1	12
24460	DUTCHWND	1	12
24465	MORWIND	1	12
28503	NORTHWND	1	12
28504	ZONDWND1	1	12
28505	ZONDWND2	1	12
25618	PEARBMBP	5	6
25618	PEARBMBP	6	6
25619	PEARBMCP	7	6
25619	PEARBMCP	8	6
25617	PEARBMAP	1	5
25617	PEARBMAP	2	5
25620	PEARBMDP	9	5

24136	SEAWEST	1	5

Rector Sub-area

The most critical contingency for the Rector sub-area is the loss of one of the Rector-Vestal 230 kV lines with the Eastwood unit out of service, which would thermally overload the remaining Rector-Vestal 230 kV line. This limiting contingency establishes a LCR of 525 MW (includes 4 MW of QF generation) in 2012 as the minimum capacity necessary for reliable load serving capability within this sub-area.

Effectiveness factors:

The following table has units that have at least 5% effectiveness to the above-mentioned constraint within Rector sub-area:

Gen Bus	Gen Name	Gen ID	Eff Fctr (%)
24370	KAWGEN	1	45
24319	EASTWOOD	1	41
24306	B CRK1-1	1	41
24306	B CRK1-1	2	41
24307	B CRK1-2	3	41
24307	B CRK1-2	4	41
24323	PORTAL	1	41
24308	B CRK2-1	1	40
24308	B CRK2-1	2	40
24309	B CRK2-2	3	40
24309	B CRK2-2	4	40
24315	B CRK 8	81	40
24315	B CRK 8	82	40
24310	B CRK2-3	5	39
24310	B CRK2-3	6	39
24311	B CRK3-1	1	39
24311	B CRK3-1	2	39
24312	B CRK3-2	3	39
24312	B CRK3-2	4	39
24313	B CRK3-3	5	39
24317	MAMOTH1G	1	39
24318	MAMOTH2G	2	39
24314	B CRK 4	41	38
24314	B CRK 4	42	38

Vestal Sub-area

The most critical contingency for the Vestal sub-area is the loss of one of the Magunden-Vestal 230 kV lines with the Eastwood unit out of service, which would thermally overload the remaining Magunden-Vestal 230 kV line. This limiting contingency establishes a LCR of 776 MW in 2012 (which includes 88 MW of QF generation) as the minimum capacity necessary for reliable load serving capability within this sub-area.

Effectiveness factors:

The following table has units that have at least 5% effectiveness to the above-mentioned constraint within Vestal sub-area:

Gen Bus	Gen Name	Gen ID	Eff Fctr (%)
28008	LAKEGEN	1	46
24113	PANDOL	1	45
24113	PANDOL	2	45
24150	ULTRAGEN	1	45
24372	KR 3-1	1	45
24373	KR 3-2	2	45
24152	VESTAL	1	45
24370	KAWGEN	1	45
24319	EASTWOOD	1	24
24306	B CRK1-1	1	24
24306	B CRK1-1	2	24
24307	B CRK1-2	3	24
24307	B CRK1-2	4	24
24308	B CRK2-1	1	24
24308	B CRK2-1	2	24
24309	B CRK2-2	3	24
24309	B CRK2-2	4	24
24310	B CRK2-3	5	24
24310	B CRK2-3	6	24
24315	B CRK 8	81	24
24315	B CRK 8	82	24
24323	PORTAL	1	24
24311	B CRK3-1	1	23
24311	B CRK3-1	2	23
24312	B CRK3-2	3	23
24312	B CRK3-2	4	23
24313	B CRK3-3	5	23
24317	MAMOTH1G	1	23
24318	MAMOTH2G	2	23
24314	B CRK 4	41	22
24314	B CRK 4	42	22

S. Clara sub-areas

The most critical contingency for the S.Clara sub-area is the loss of the Pardee to S.Clara 230 kV line followed by the loss of the Moorpark to S.Clara #1 and #2 230 kV lines, which would cause voltage collapse. This limiting contingency establishes a LCR of 296 MW in 2012 (which includes 64 MW of QF generation) as the minimum capacity necessary for reliable load serving capability within this sub-area.

Effectiveness factors:

The generators inside the sub-area have the same effectiveness factors.

Moorpark sub-areas

The most critical contingency for the Moorpark sub-area is the loss of one of the Pardee to Moorpark 230 kV lines followed by the loss of the remaining two Moorpark to Pardee 230 kV lines, which would cause voltage collapse. This limiting contingency establishes a LCR of 377 MW in 2012 (which includes 92 MW of QF generation) as the minimum capacity necessary for reliable load serving capability within this sub-area.

Effectiveness factors:

The generators inside the sub-area have the same effectiveness factors.

Changes compared to last year's results:

Overall the load forecast went up by 45 MW. The overall effect is that the LCR has increase by 307 MW. The higher LCR increase is due to load allocation change within the Big Creek Ventura.

Big Creek Overall Requirements:

2012	QF/Wind (MW)	MUNI (MW)	Market (MW)	Max. Qualifying Capacity (MW)
Available generation	808	383	4041	5232

2012	Existing Generation Capacity Needed (MW)	Deficiency (MW)	Total MW LCR Need
Category B (Single)[25]	3093	0	3093
Category C (Multiple)[26]	3093	0	3093

[25] A single contingency means that the system will be able the survive the loss of a single element, however the operators will not have any means (other then load drop) in order to bring the system within a safe operating zone and get prepared for the next contingency as required by MORC.

[26] Multiple contingencies means that the system will be able the survive the loss of a single element, and the operators will have enough generation (other operating procedures) in order to bring the system within a safe operating zone and get prepared for the next contingency as required by MORC.

10. San Diego Area

Area Definition

The transmission tie lines forming a boundary around San Diego include:

1) Imperial Valley – Miguel 500 kV Line
2) Imperial Valley – Central 500kV Line
3) Otay Mesa – Tijuana 230 kV Line
4) San Onofre - San Luis Rey #1 230 kV Line
5) San Onofre - San Luis Rey #2 230 kV Line
6) San Onofre - San Luis Rey #3 230 kV Line
7) San Onofre – Talega #1 230 kV Line
8) San Onofre – Talega #2 230 kV Line

The substations that delineate the San Diego Area are:

1) Imperial Valley is out Miguel is in
2) Imperial Valley is out Central is in
3) Otay Mesa is in Tijuana is out
4) San Onofre is out San Luis Rey is in
5) San Onofre is out San Luis Rey is in
6) San Onofre is out San Luis Rey is in
7) San Onofre is out Talega is in
8) San Onofre is out Talega is in

Total 2012 busload within the defined area: 4770 MW with 74 MW of losses resulting in total load + losses of 4844 MW.

Total units and qualifying capacity available in this area:

MKT/SCHED RESOURCE ID	BUS #	BUS NAME	kV	NQC	UNIT ID	LCR SUB-AREA NAME	NQC Comments	CAISO Tag
BORDER_6_UNITA1	22149	CALPK_BD	13.8	43.80	1	Border		Market
CBRLLO_6_PLSTP1	22092	CABRILLO	69	2.15	1		Aug NQC	QF/Selfgen
CCRITA_7_RPPCHF	22124	CHCARITA	138	2.63	1		Aug NQC	QF/Selfgen
CHILLS_1_SYCLFL	22120	CARLTNHS	138	0.43	1		Aug NQC	QF/Selfgen
CHILLS_7_UNITA1	22120	CARLTNHS	138	1.26	2		Aug NQC	QF/Selfgen
CPSTNO_7_PRMADS	22112	CAPSTRNO	138	3.49	1		Aug NQC	QF/Selfgen
CRSTWD_6_KUMYAY	22915	KUMEYAAY	34.5	6.46	1		Aug NQC	Wind
DIVSON_6_NSQF	22172	DIVISION	69	36.47	1		Aug NQC	QF/Selfgen

EGATE_7_NOCITY	22204	EASTGATE	69	0.21	1		Aug NQC	QF/Selfgen
ELCAJN_6_LM6K	23320	C509	13.8	48.00	1	El Cajon		Market
ELCAJN_6_UNITA1	22150	CALPK_EC	13.8	42.20	1	El Cajon		Market
ELCAJN_7_GT1	22212	ELCAJNGT	12.5	16.00	1	El Cajon		Market
ENCINA_7_EA1	22233	ENCINA 1	14.4	106.00	1			Market
ENCINA_7_EA2	22234	ENCINA 2	14.4	104.00	1			Market
ENCINA_7_EA3	22236	ENCINA 3	14.4	110.00	1			Market
ENCINA_7_EA4	22240	ENCINA 4	22	300.00	1			Market
ENCINA_7_EA5	22244	ENCINA 5	24	330.00	1			Market
ENCINA_7_GT1	22248	ENCINAGT	12.5	14.00	1			Market
ESCNDO_6_PL1X2	22257	ESGEN	13.8	35.50	1			Market
ESCNDO_6_UNITB1	22153	CALPK_ES	13.8	45.50	1			Market
ESCO_6_GLMQF	22332	GOALLINE	69	44.04	1	Esco	Aug NQC	QF/Selfgen
KEARNY_7_KY1	22377	KEARNGT1	12.5	16.00	1	Rose Canyon, Mission		Market
KEARNY_7_KY2	22373	KEARN2AB	12.5	15.02	1	Rose Canyon, Mission		Market
KEARNY_7_KY2	22374	KEARN2CD	12.5	15.02	1	Rose Canyon, Mission		Market
KEARNY_7_KY2	22373	KEARN2AB	12.5	15.02	2	Rose Canyon, Mission		Market
KEARNY_7_KY2	22374	KEARN2CD	12.5	13.95	2	Rose Canyon, Mission		Market
KEARNY_7_KY3	22375	KEARN3AB	12.5	14.98	1	Rose Canyon, Mission		Market
KEARNY_7_KY3	22376	KEARN3CD	12.5	14.98	1	Rose Canyon, Mission		Market
KEARNY_7_KY3	22375	KEARN3AB	12.5	16.05	2	Rose Canyon, Mission		Market
KEARNY_7_KY3	22376	KEARN3CD	12.5	14.98	2	Rose Canyon, Mission		Market
LARKSP_6_UNIT 1	22074	LRKSPBD1	13.8	46.00	1	Border		Market
LARKSP_6_UNIT 2	22075	LRKSPBD2	13.8	46.00	1	Border		Market
MRGT_6_MEF2	22487	MFE_MR2	13.8	47.90	1	Mission		Market
MRGT_6_MMAREF	22486	MFE_MR1	13.8	46.60	1	Mission		Market
MRGT_7_UNITS	22488	MIRAMRGT	12.5	18.55	1	Mission		Market
MRGT_7_UNITS	22488	MIRAMRGT	12.5	17.45	2	Mission		Market
MSHGTS_6_MMARLF	22448	MESAHGTS	69	2.94	1	Mission	Aug NQC	QF/Selfgen
MSSION_2_QF	22496	MISSION	69	0.80	1		Aug NQC	QF/Selfgen
NIMTG_6_NIQF	22576	NOISLMTR	69	34.16	1		Aug NQC	QF/Selfgen
OGROVE_6_PL1X2	22628	PA99MWQ1	13.8	49.95	1			Market
OGROVE_6_PL1X2	22629	PA99MWQ2	13.8	49.95	2			Market
OTAY_6_PL1X2	22617	OYGEN	13.8	35.50	1			Market
OTAY_6_UNITB1	22604	OTAY	69	2.90	1		Aug NQC	QF/Selfgen
OTAY_7_UNITC1	22604	OTAY	69	2.70	3		Aug NQC	QF/Selfgen
OTMESA_2_PL1X3	22605	OTAYMGT1	18	185.06	1			Market
OTMESA_2_PL1X3	22606	OTAYMGT2	18	185.06	1			Market
OTMESA_2_PL1X3	22607	OTAYMST1	16	233.48	1			Market
PALOMR_2_PL1X3	22262	PEN_CT1	18	162.17	1			Market
PALOMR_2_PL1X3	22263	PEN_CT2	18	162.17	1			Market
PALOMR_2_PL1X3	22265	PEN_ST	18	240.66	1			Market
PTLOMA_6_NTCCGN	22660	POINTLMA	69	1.64	2		Aug NQC	QF/Selfgen
PTLOMA_6_NTCQF	22660	POINTLMA	69	17.18	1		Aug NQC	QF/Selfgen
SAMPSN_6_KELCO1				2.72			Aug NQC	QF/Selfgen
SMRCOS_6_UNIT 1	22724	SANMRCOS	69	0.65	1		Aug NQC	QF/Selfgen
NA	22916	PFC-AVC	0.6	0.00	1		No NQC -	QF/Selfgen

							hist. data	
LAKHDG_6_UNIT 1	22625	LKHODG1	13.8	20.00	1	Bernardo	No NQC - Pmax	Market
LAKHDG_6_UNIT 2	22626	LKHODG2	13.8	20.00	2	Bernardo	No NQC - Pmax	Market
New unit	23120	BULLMOOS	13.8	27.00	1	Border	No NQC - Pmax	Market

Major new projects modeled:

1. Sunrise Power Link Project (Southern Route)
2. 3 small new resources and the LGIP upgrades associated with Bullmoose Project (Otay – Otay Lake Tap 69kV, TL649 reconductor)
3. Retirement of South Bay Power Plant
4. Eastgate – Rose Canyon 69kV (TL6927) reconductor

<u>Critical Contingency Analysis Summary</u>

El Cajon Sub-area:

The most critical contingency for the El Cajon sub-area is the loss of the El Cajon-Jamacha 69 kV line (TL624) followed by the loss of Miguel-Granite-Los Coches 69 kV line (TL632), which would thermally overload the Garfield-Murray 69 kV line. This limiting contingency establishes a LCR of 35 MW (including 0 MW of QF generation) in 2012 as the minimum generation capacity necessary for reliable load serving capability within this sub-area.

Effectiveness factors:

All units within this sub-area (El Cajon Peaker, El Cajon GT, and new peaker at El Cajon substation) have the same effectiveness factor.

Rose Canyon Sub-area

This sub-area has been eliminated due to recently approved transmission project, TL6927, Eastgate-Rose Canyon 69 kV reconductor. If the project reconductoring is delayed beyond June 1, 2012, the most critical contingency for the Rose Canyon sub area will be the loss of Imperial Valley – Miguel 500kV line (TL50001) followed by the loss of Rose Canyon – Miramar - Penasquitos 69kV line (TL664A) would thermally overload Eastgate – Rose Canyon 69kV line (TL6927). This limiting contingency would establish a local capacity need of 53 MW (includes 0 MW of QF generation) in 2012.

Effectiveness factors:

All units within this area (Kearny GTs) have the same effectiveness factor.

Mission Sub-area

The most critical contingency for the Mission sub-area is the loss of Mission - Kearny 69 kV line (TL663) followed by the loss of Mission – Mesa Heights 69kV line (TL676), which would thermally overload the Mission - Clairmont 69kV line (TL670). This limiting contingency establishes a local capacity need of 233 MW (including 3 MW of QF generation) in 2012.

Effectiveness factors:

Miramar Energy Facility units and Miramar GTs (Cabrillo Power II) are 6% effective, Miramar Landfill unit and all Kearny peakers are 32% effective.

Bernardo Sub-area:

The most critical contingency for the Bernardo sub-area is the loss of Artesian - Sycamore 69 kV line followed by the loss of Poway-Rancho Carmel 69 kV line, which would thermally overload the Felicita Tap-Bernardo 69 kV line (TL689). This limiting contingency establishes a LCR of 105 MW (including 0 MW of QF generation and 65 MW of deficiency) in 2012 as the minimum generation capacity necessary for reliable load serving capability within this sub-area.

Effectiveness factors:

All units within this sub-area (Lake Hodges) are needed so there is no effectiveness factor required.

Border Sub-area

Sub-area eliminated due to new generation project upgrade, reconductor TL649A, Otay-Otay Lakes Tap 69 kV. If the project reconductoring is delayed beyond June 1, 2012, the most critical contingency for the Border sub area will be the loss of Border – Miguel 69 kV line (TL6910) followed by the loss of Imperial Beach-Otay-San Ysidro 69 kV line (TL623), which would thermally overload Otay-Otay Lake Tap (TL649). This limiting contingency would establish a local capacity need of 27 MW (includes 0 MW of QF generation) in 2012 as the minimum generation capacity necessary for reliable load serving capability within this sub area.

Effectiveness factors:

If the reconductoring project is completed by June 1, 2012, no units will be needed. If the project is not completed, Border Cal Peak, Larkspur and Bullmoose all have the same effectiveness factor.

Esco Sub-area

The most critical contingency for the Esco sub-area is the loss of Poway-Pomerado 69 kV line followed by the loss of Bernardo-Rancho Carmel 69kV line which would thermally overload the Esco-Escondido 69 kV line. This limiting contingency establishes a LCR of 74 MW (including 44 MW of QF generation and 30 MW of deficiency) in 2012 as the minimum generation capacity necessary for reliable load serving capability within this sub-area.

Effectiveness factors:

Only unit within this sub-area (Goal line) is needed so no effectiveness factor is required.

San Diego overall:

The most limiting contingency in the San Diego area is described by the outage of the 500 kV Southwest Power Link (SWPL) between Imperial Valley and Miguel Substations over-lapping with an outage of the Otay Mesa Combined-Cycle Power plant (603 MW) while staying within the 1000 MW rating of Imperial Valley - Central 500 kV line (Sunrise Power Link). Post-contingency import limit of 3,500 MW is not the most limiting condition here. Sunrise Power Link hits 1,000 MW before SDGE import hits 3,500 MW. This contingency establishes a LCR of 2849 MW in 2012 (includes 156 MW of QF generation and 6 MW of Wind) as the minimum generation capacity necessary for reliable load serving capability within this area.

If the Sunrise Power Link is delayed beyond June 1, 2012, the most critical contingency for the San Diego overall area will be the loss of Imperial Valley – Miguel 500 kV line with Otay Mesa Power Plant out of service, which would require the system to be within the South of SONGS path rating of 2500 MW. This limiting contingency would establish a local capacity need of 2989 MW (includes 156 MW of QF generation and 6 MW of Wind) in 2012 as the minimum generation capacity necessary for reliable load serving capability within this sub area.

Effectiveness factors:
All units within this area have the same effectiveness factor. Units outside of this area are not effective.

Greater IV-San Diego area:
The most limiting contingency in the Greater Imperial Valley-San Diego area is described by the outage of 500 kV Southwest Power Link (SWPL) between Imperial Valley and N. Gila Substations over-lapping with an outage of the Otay Mesa Combined-Cycle Power plant (603 MW) while staying within the South of San Onofre (WECC Path 44) non-simultaneous import capability rating of 2,500 MW. This limiting contingency establishes a local capacity need of 2804 MW in 2012 as the minimum capacity necessary for reliable load serving capability within this area. It is worth mentioning that there were no additional upgrades modeled between the IID and CAISO or CFE and CAISO control areas at Imperial Valley 230 kV bus in 2012 base case. The CAISO acknowledges that the LCR needs for the Greater Imperial Valley-San Diego area will decrease as additional transmission is constructed between the IID/CFE systems and Imperial Valley and more power is flowing in real-time from these control areas into the CAISO control area.

The Greater Imperial Valley/San Diego area and San Diego Overall LCR needs are very similar in magnitude. In future years, either of these areas may become more stringent depending on the study assumptions and future projects.

The CAISO will continue to use the existing San Diego boundary as a local area for year 2012 because the requirements of the Greater Imperial Valley/San Diego area are not binding during 2012 and because a delay in Sunrise Power Link construction would require even higher local requirement within the existing San Diego area.

Changes compared to last year's results:

Overall the load forecast went down by 182 MW and total resource capacity needed for LCR decreased by 297 MW. The addition of Sunrise Power Link is the reason for the further decrease in LCR beyond load forecast.

San Diego Overall Requirements:

2012	QF (MW)	Wind (MW)	Market (MW)	Max. Qualifying Capacity (MW)
Available generation	156	6	2925	3087

2012	Existing Generation Capacity Needed (MW)	Deficiency (MW)	Total MW LCR Need
Category B (Single)[27]	2849	0	2849
Category C (Multiple)[28]	2849	95	2944

[27] A single contingency means that the system will be able the survive the loss of a single element, however the operators will not have any means (other then load drop) in order to bring the system within a safe operating zone and get prepared for the next contingency as required by MORC.

[28] Multiple contingencies means that the system will be able the survive the loss of a single element, and the operators will have enough generation (other operating procedures) in order to bring the system within a safe operating zone and get prepared for the next contingency as required by MORC.

EXHIBIT F

Docket No. 07-AFC-6

CENTER FOR BIOLOGICAL DIVERSITY'S RESPONSE IN SUPPORT OF CITY OF CARLSBAD'S MOTION TO TAKE OFFICIAL NOTICE AND THE CENTER'S MOTION TO TAKE OFFICIAL NOTICE AND RE-OPEN THE EVIDENTIARY RECORD

SOUTHERN CALIFORNIA
EDISON
An EDISON INTERNATIONAL Company

Akbar Jazayeri
Vice President of Regulatory Operations

January 31, 2011

ADVICE 2547-E
(U 338-E)

PUBLIC UTILITIES COMMISSION OF THE STATE OF CALIFORNIA
ENERGY DIVISION

SUBJECT: Submission of Contracts for Procurement of Renewable Energy Resulting from Renewables Standard Contracts Program

I. INTRODUCTION

A. Purpose of the Advice Letter

Southern California Edison Company ("SCE") submits this Advice Letter in compliance with Cal. Pub. Util. Code § 399.11 *et seq*. (the "RPS Legislation") seeking approval of 20 Renewables Portfolio Standard ("RPS") power purchase agreements ("RSC Contracts") resulting from SCE's 2010 Renewables Standard Contracts ("RSC") Program.

The following table summarizes the RSC Contracts:

Seller	Generation Type	Contract Capacity (MW AC)	Estimated Annual Energy (GWh)	Forecasted Initial Operation Date	Point of Delivery	Term of Agreement (Years)
Lancaster Dry Farm Ranch B LLC	Solar: PV	5.0	12.2	4/2014	PNode	20
Sierra Solar Greenworks LLC	Solar: PV	20.0	41.2	4/2014	PNode	20
Lancaster WAD B LLC	Solar: PV	5.0	12.4	4/2014	PNode	20

Central Antelope Dry Ranch B LLC	Solar: PV	5.0	10.2	4/2014	PNode	20
Central Antelope Dry Ranch C LLC	Solar: PV	20.0	40.8	4/2014	PNode	20
Victor Dry Farm Ranch A LLC	Solar: PV	5.0	10.3	4/2014	PNode	20
Victor Dry Farm Ranch B LLC	Solar: PV	5.0	10.3	4/2014	PNode	20
North Lancaster Ranch LLC	Solar: PV	20.0	40.8	4/2014	PNode	20
American Solar Greenworks LLC	Solar: PV	15.0	30.9	4/2014	PNode	20
Sierra View Solar V LLC	Solar: PV	19.0	50.0	12/2013	PNode	20
Sierra View Solar IV LLC	Solar: PV	19.0	49.4	12/2013	PNode	20
Nicolis, LLC	Solar: PV	20.0	50.1	9/2013	PNode	20
Blythe Solar Power Generation Station 1, LLC	Solar: PV	4.7	12.2	6/2013	PNode	20
Littlerock Solar Power Generation Station 1, LLC	Solar: PV	5.0	13.6	4/2013	PNode	20
Garnet Solar Power Generation Station 1, LLC	Solar: PV	4.8	11.3	6/2013	PNode	20
Lucerne Solar Power Generation Station 1, LLC	Solar: PV	14.0	37.6	3/2014	PNode	20
Tropico, LLC	Solar: PV	14.0	36.2	9/2013	PNode	20
Clear Peak Energy, Inc.	Solar: PV	8.5	23.6	12/2013	PNode	20
RE Columbia 3 LLC	Solar: PV	10.0	24.9	1/2014	PNode	20
RE Columbia Two LLC	Solar: PV	20.0	49.3	1/2014	PNode	20

SCE requests that the California Public Utilities Commission ("Commission" or "CPUC") issue a resolution containing findings in the form requested in this Advice Letter no later than July 29, 2011.

In accordance with General Order ("GO") 96-B, the confidentiality of information included in this Advice Letter is described below. This Advice Letter contains both confidential and public appendices as listed below:

Confidential Appendix A:	Consistency with Commission Decisions and Rules and Project Development Status
Confidential Appendix B:	2010 RSC Program Solicitation Overview and 2009 Solicitation Workpapers
Confidential/Public Appendix C:	Independent Evaluator Report
Confidential Appendix D:	Contract Summaries
Confidential Appendix E:	RSC Contracts’ Contribution to RPS Goals
Appendix F:	SCE’s Written Description of RPS Proposal Evaluation and Selection Process and Criteria
Confidential Appendix G:	AMF Calculators
Confidential Appendix H.1:	Lancaster Dry Farm Ranch B PPA
Confidential Appendix H.2:	Comparison of Lancaster Dry Farm Ranch B PPA to 2010 RSC Pro Forma
Confidential Appendix I.1:	Sierra Solar Greenworks PPA
Confidential Appendix I.2:	Comparison of Sierra Solar Greenworks PPA to 2010 RSC Pro Forma
Confidential Appendix J.1:	Lancaster WAD B PPA
Confidential Appendix J.2:	Comparison of Lancaster WAD B PPA to 2010 RSC Pro Forma
Confidential Appendix K.1:	Central Antelope Dry Ranch B PPA
Confidential Appendix K.2:	Comparison of Central Antelope Dry Ranch B PPA to 2010 RSC Pro Forma
Confidential Appendix L.1:	Central Antelope Dry Ranch C PPA
Confidential Appendix L.2:	Comparison of Central Antelope Dry Ranch C PPA to 2010 RSC Pro Forma
Confidential Appendix M.1:	Victor Dry Farm Ranch A PPA
Confidential Appendix M.2:	Comparison of Victor Dry Farm Ranch A PPA to 2010 RSC Pro Forma
Confidential Appendix N.1:	Victor Dry Farm Ranch B PPA

Confidential Appendix N.2:	Comparison of Victor Dry Farm Ranch B PPA to 2010 RSC Pro Forma
Confidential Appendix O.1:	North Lancaster Ranch PPA
Confidential Appendix O.2:	Comparison of North Lancaster Ranch PPA to 2010 RSC Pro Forma
Confidential Appendix P.1:	American Solar Greenworks PPA
Confidential Appendix P.2:	Comparison of American Solar Greenworks PPA to 2010 RSC Pro Forma
Confidential Appendix Q.1:	Sierra View Solar V PPA
Confidential Appendix Q.2:	Comparison of Sierra View Solar V PPA to 2010 RSC Pro Forma
Confidential Appendix R.1:	Sierra View Solar IV PPA
Confidential Appendix R.2:	Comparison of Sierra View Solar IV PPA to 2010 RSC Pro Forma
Confidential Appendix S.1:	Nicolis PPA
Confidential Appendix S.2:	Comparison of Nicolis PPA to 2010 RSC Pro Forma
Confidential Appendix T.1:	Blythe Solar Power Generation Station 1 PPA
Confidential Appendix T.2:	Comparison of Blythe Solar Power Generation Station 1 PPA to 2010 RSC Pro Forma
Confidential Appendix U.1:	Littlerock Solar Power Generation Station 1 PPA
Confidential Appendix U.2:	Comparison of Littlerock Solar Power Generation Station 1 PPA to 2010 RSC Pro Forma
Confidential Appendix V.1:	Garnet Solar Power Generation Station 1 PPA
Confidential Appendix V.2:	Comparison of Garnet Solar Power Generation Station 1 PPA to 2010 RSC Pro Forma
Confidential Appendix W.1:	Lucerne Solar Power Generation Station 1 PPA
Confidential Appendix W2:	Comparison of Lucerne Solar Power Generation Station 1 PPA to 2010 RSC Pro Forma
Confidential Appendix X.1:	Tropico PPA

Confidential Appendix X.2:	Comparison of Tropico PPA to 2010 RSC Pro Forma
Confidential Appendix Y.1:	Clear Peak Energy PPA
Confidential Appendix Y.2:	Comparison of Clear Peak Energy PPA to 2010 RSC Pro Forma
Confidential Appendix Z.1:	RE Columbia 3 PPA
Confidential Appendix Z.2:	Comparison of RE Columbia 3 PPA to 2010 RSC Pro Forma
Confidential Appendix AA.1:	RE Columbia Two PPA
Confidential Appendix AA.2:	Comparison of RE Columbia Two PPA to 2010 RSC Pro Forma
Confidential Appendix BB:	Project Viability Calculators
Appendix CC:	Confidentiality Declaration
Appendix DD:	Proposed Protective Order

B. Subject of the Advice Letter

SCE's 2010 RSC Program offered two different contracts which vary depending on the size of the generating facility – one for facilities with capacities not greater than 5 MW and one for facilities with capacities greater than 5 MW but not greater than 20 MW. The RSC Contracts were offered to RPS-eligible resources for terms of 10, 15, and 20 years. The contracts were based on a simplified version of the Pro Forma Renewable Power Purchase and Sale Agreement for SCE's 2010 RPS solicitation.[1]

On September 15, 2010, SCE received a large number of offers for the 2010 RSC Program, representing over ten times the program's goal of 250 MW. SCE conducted a competitive solicitation using a reverse auction. All interested parties were allowed to comment on the pro forma contract and SCE incorporated many suggested changes prior to accepting offers. Project offers were submitted by offerors at a bid price they determined. Projects were then ranked by levelized price and selected from lowest to

[1] SCE filed its 2010 RPS Procurement Plan on December 19, 2009. SCE subsequently filed two motions to amend its plan, accompanied by amended versions of the 2010 RPS Procurement Plan, on April 9, 2010 and June 17, 2010. The approval of the 2010 RPS Procurement Plan is pending at the CPUC.

highest levelized price up to the 250 MW program cap. SCE seeks approval in this Advice Letter for 20 contracts executed through the 2010 RSC Program.[2]

All of the RSC Contracts are for 20-year terms and are for solar photovoltaic ("PV") projects constructing new facilities. Solar PV is a mature and proven renewable energy technology that has been supplying a substantial amount of renewable energy to SCE and other California load-serving entities ("LSEs") for several years. All RSC Contracts are priced below the approved 2009 market price referents ("MPRs"), the most current MPRs available when the offers for the RSC Contracts were received.[3]

The table below provides information regarding each of the 20 RSC Contracts. Additional information regarding the owners and developers of the 20 projects can be found in section III.A.

Project name	**Technology**	**General Location**	**Interconnection Point**	**Owner(s) / Developer(s)**	**Project background**	**Source of agreement**
Lancaster Dry Farm Ranch B	Solar PV	Lancaster	Switchgear on site	Silverado Power	New Project	RSC RFO
Sierra Solar Greenworks	Solar PV	Lancaster	Switchgear on site	Silverado Power	New Project	RSC RFO
Lancaster WAD B	Solar PV	Lancaster	Switchgear on site	Silverado Power	New Project	RSC RFO
Central Antelope Dry Ranch B	Solar PV	Lancaster	Switchgear on site	Silverado Power	New Project	RSC RFO
Central Antelope Dry Ranch C	Solar PV	Lancaster	Switchgear on site	Silverado Power	New Project	RSC RFO
Victor Dry Farm Ranch A	Solar PV	Victorville	Switchgear on site	Silverado Power	New Project	RSC RFO
Victor Dry Farm Ranch B	Solar PV	Victorville	Switchgear on site	Silverado Power	New Project	RSC RFO
North Lancaster Ranch	Solar PV	Lancaster	Switchgear on site	Silverado Power	New Project	RSC RFO
American Solar	Solar PV	Lancaster	Switchgear on site	Silverado Power	New Project	RSC RFO

2 A total of 21 contracts were originally executed through the 2010 RSC Program. One contract was subsequently terminated.

3 The 2009 MPRs were approved on December 17, 2009, in Resolution E-4298. No 2010 MPRs have been issued by the CPUC.

Project name	Technology	General Location	Interconnection Point	Owner(s) / Developer(s)	Project background	Source of agreement
Greenworks						
Sierra View Solar V	Solar PV	Mojave	Lancaster-Goldtown 66kV Line	juwi solar Inc.	New Project	RSC RFO
Sierra View Solar IV	Solar PV	Lancaster	Antelope - Neenach 66kV Line	juwi solar Inc.	New Project	RSC RFO
Weldon Solar	Solar PV	Weldon	Weldon substation	Foresight Renewables, LLC	New Project	RSC RFO
Blythe Solar Power Generation Station, 1 LLC	Solar PV	Blythe	Wedge / 12kV	Amonix, Inc.	New Project	RSC RFO
Littlerock Solar Power Generation Station, 1 LLC	Solar PV	Littlerock	Caliber 12kV line	Amonix, Inc.	New Project	RSC RFO
Garnet Solar Power Generation Station, 1 LLC	Solar PV	North Palm Springs	Pierson/33kV	Amonix, Inc.	New Project	RSC RFO
Lucerne Solar Power Generation Station, 1 LLC	Solar PV	Lucerne Valley	Lucerne Circuit / 33kV	Amonix, Inc.	New Project	RSC RFO
Great Lakes	Solar PV	Rosamond	Great Lakes substation	Foresight Renewables, LLC	New Project	RSC RFO
Holiday Solar Array	Solar PV	Rosamond	Neenach/12kV	Clear Peak Energy, Inc.	New Project	RSC RFO
RE Columbia 3	Solar PV	Mojave	12kV Line on Purdy Ave	Recurrent Energy	New Project	RSC RFO
RE Columbia Two	Solar PV	Mojave	66kV Line between Goldtown and Lancaster	Recurrent Energy	New Project	RSC RFO

C. General Project Description

The following table provides a general overview of the 20 RSC Contracts:

Project Name	Various
Technology	Solar PV
Capacity (MW)	Ranging from 4.71 MW to 20 MW
Capacity Factor	Ranging from 23% to 32%
Expected Generation (GWh/Year)	Total 567 GWh/Year
Initial commercial operational date	Ranging from April 3, 2013 to April 30, 2014
Date contract Delivery Term begins	Commercial Operation Date
Delivery Term (Years)	20
Vintage (New / Existing / Repower)	New
Location (city and state)	Various within California
Control Area (e.g., CAISO, BPA)	CAISO
Nearest Competitive Renewable Energy Zone (CREZ) as identified by the Renewable Energy Transmission Initiative (RETI)	18 projects – N/A 2 projects in Tehachapi CREZ: - Sierra View Solar V - Holiday Solar Array
Type of cooling, if applicable	None
Price relative to MPR (i.e. above/below)	Below

The table below provides specific details for each of the 20 RSC Contracts individually:

Project Name	Technology	Capacity (MW)	Capacity Factor	Expected Generation (GWh/Year)	Initial commercial operational date	Date contract Delivery Term begins	Delivery Term (Years)	Vintage	Location (all in CA)	Control Area	Nearest Competitive Renewable Energy Zone (CREZ) as identified by the Renewable Energy Transmission Initiative (RETI)[1]	Type of cooling, if applicable	Price relative to MPR
Lancaster Dry Farm Ranch B	Solar: PV	5.00	30.1%	12,230	4/2014	Commerical Operation Date	20	New	Lancaster	CAISO	N/A	None	below
Sierra Solar Greenworks	Solar: PV	20.00	23.5%	41,240	4/2014	Commerical Operation Date	20	New	Lancaster	CAISO	N/A	None	below
Lancaster WAD B	Solar: PV	5.00	30.1%	12,360	4/2014	Commerical Operation Date	20	New	Lancaster	CAISO	N/A	None	below
Central Antelope Dry Ranch B	Solar: PV	5.00	23.5%	10,200	4/2014	Commerical Operation Date	20	New	Lancaster	CAISO	N/A	None	below
Central Antelope Dry Ranch C	Solar: PV	20.00	23.5%	40,800	4/2014	Commerical Operation Date	20	New	Lancaster	CAISO	N/A	None	below
Victor Dry Farm Ranch A	Solar: PV	5.00	23.5%	10,290	4/2014	Commerical Operation Date	20	New	Victorville	CAISO	N/A	None	below
Victor Dry Farm Ranch B	Solar: PV	5.00	23.5%	10,290	4/2014	Commerical Operation Date	20	New	Victorville	CAISO	N/A	None	below
North Lancaster Ranch	Solar: PV	20.00	23.5%	40,810	4/2014	Commerical Operation Date	20	New	Lancaster	CAISO	N/A	None	below
American Solar Greenworks	Solar: PV	15.00	23.5%	30,930	4/2014	Commerical Operation Date	20	New	Lancaster	CAISO	N/A	None	below
Sierra View Solar V	Solar: PV	19.00	27.3%	49,974	3/2014	Commerical Operation Date	20	New	Mojave	CAISO	Tehachapi	None	below
Sierra View Solar IV	Solar: PV	19.00	27.0%	49,391	3/2014	Commerical Operation Date	20	New	Lancaster	CAISO	N/A	None	below
Weldon Solar	Solar: PV	20.00	28.6%	50,120	9/2013	Commerical Operation Date	20	New	Weldon	CAISO	N/A	None	below
Blythe Solar Power Generation Station, 1 LLC	Solar: PV	4.71	25.1%	12,157	6/2013	Commerical Operation Date	20	New	Blythe	CAISO	N/A	None	below
Littlerock Solar Power Generation Station, 1 LLC	Solar: PV	5.00	26.4%	13,608	4/2013	Commerical Operation Date	20	New	Littlerock	CAISO	N/A	None	below
Garnet Solar Power Generation Station, 1 LLC	Solar: PV	4.78	23.0%	11,313	6/2013	Commerical Operation Date	20	New	North Palm Springs	CAISO	N/A	None	below
Lucerne Solar Power Generation Station, 1 LLC	Solar: PV	13.97	26.1%	37,587	3/2014	Commerical Operation Date	20	New	Lucerne Valley	CAISO	N/A	None	below
Great Lakes	Solar: PV	14.00	29.6%	36,240	9/2013	Commerical Operation Date	20	New	Rosamond	CAISO	N/A	None	below
Holiday Solar Array	Solar: PV	8.50	31.6%	23,552	12/2013	Commerical Operation Date	20	New	Lancaster	CAISO	Tehachapi	None	below
RE Columbia 3	Solar: PV	10.00	28.4%	24,901	1/2014	Commerical Operation Date	20	New	Mojave	CAISO	N/A	None	below
RE Columbia Two	Solar: PV	20.00	28.1%	49,293	1/2014	Commerical Operation Date	20	New	Mojave	CAISO	N/A	None	below

D. General Deal Structure

The general deal structure for all 20 RSC projects is the same, and is based on a simplified version of the Pro Forma Renewable Power Purchase and Sale Agreement for SCE's 2010 RPS solicitation. SCE is purchasing all electric energy produced by the RSC projects throughout the contract terms, including all green attributes, capacity attributes, and resource adequacy benefits generated by, associated with, or attributable to, the output from the generating facilities.

All 20 RSC Contracts have 20-year terms, which begin on their respective commercial operation dates. The term start date must occur within three years of CPUC approval.[4] Each producer will post development security. For producers with a project not greater than 5 MW, the development security will be $30 per kW of the contract capacity. For producers with a project greater than 5 MW but not greater than 20 MW, the development security will be $60 per kW of the contract capacity.[5] Performance assurance is required for producers with a project greater than 5 MW but not greater than 20 MW; the performance assurance amount ranges, during the term, from 3 percent to 6 percent of total project revenues but will not be less than $1 million.

There are no firming or shaping costs in the RSC Contracts. All of the interconnection points and delivery points are within California and the California Independent System Operator ("CAISO")-controlled grid. Additional information regarding the deal structure of the RSC Contracts is provided in Appendix D.

E. RPS Statutory Goals

By providing renewable energy from an eligible renewable energy resource ("ERR") as defined under the RPS Legislation, the RSC projects are consistent with, and contribute to, the RPS program's statutory goals. Among other things, by supporting new renewable energy generation projects in California, the RSC Contracts help to ensure stable electricity prices, protect public health, improve environmental quality, stimulate economic development, and create new employment opportunities.

F. Confidentiality

SCE is requesting confidential treatment of Appendices A-B, D-E, and G-BB, as well as the confidential version of Appendix C. The information for which SCE is seeking

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[4] This term start date, however, is subject to an extension as a result of force majeure.

[5] One-half of the development security will be due within 30 days following the effective date; the other half will be due within 30 days following CPUC approval. If, by the term start date, each producer has installed all of the equipment necessary for the generating facility to operate, deliver product, and satisfy the contract capacity of the generating facility, SCE will return the development security to the producer.

confidential treatment is identified in Appendix CC hereto. The confidential version of this Advice Letter will be made available to appropriate parties (in accordance with SCE's Proposed Protective Order, as discussed below) upon execution of the required non-disclosure agreement. Parties wishing to obtain access to the confidential version of this Advice Letter may contact Joni Templeton in SCE's Law Department at Joni.Templeton@sce.com or (626) 302-6210 to obtain a non-disclosure agreement. In accordance with GO 96-B, a copy of SCE's Proposed Protective Order is attached hereto as Appendix DD. It is appropriate to accord confidential treatment to the information for which SCE requests confidential treatment in the first instance in the advice letter process because such information is entitled to confidentiality protection pursuant to Decision ("D.") 06-06-066 and is required to be filed by advice letter as part of the process for obtaining Commission approval of RPS power purchase agreements ("PPAs").

The information in this Advice Letter for which SCE requests confidential treatment, the pages on which the information appears, and the length of time for which the information should remain confidential are provided in Appendix CC. This information is entitled to confidentiality protection pursuant to D.06-06-066 (as provided in the Investor-Owned Utility ("IOU") Matrix). The specific provisions of the IOU Matrix that apply to the confidential information in this Advice Letter are identified in Appendix CC.

II. CONSISTENCY WITH COMMISSION DECISIONS

A. SCE's RPS Procurement Plans

1. SCE's 2009 RPS Procurement Plan Was Approved by the Commission and SCE Adhered to Commission Guidelines for Filing and Revisions

In D.09-06-018, the Commission conditionally approved SCE's 2009 RPS Procurement Plan, including the solicitation materials for SCE's 2009 RPS solicitation. The Commission also ordered SCE to make certain changes to its 2009 RPS Procurement Plan and to file the amended documents with the Director of the Energy Division, and serve such documents on the service list, by June 22, 2009. On June 22, 2009, SCE filed and served its Amended 2009 RPS Procurement Plan, including its amended 2009 solicitation materials. On June 26, 2009, SCE filed and served its Second Amended 2009 RPS Procurement Plan, including its further amended 2009 solicitation materials. Consistent with the schedule set forth in D.09-06-018, SCE issued its 2009 request for proposals ("RFP") on June 29, 2009.

On June 19, 2009, the Commission issued D.09-06-050, which approved a fast-track review process allowing for the use of Tier 2 advice letter filings for short-term RPS contracts of less than 10 years duration that meet certain criteria set forth in the decision. The Commission also directed the IOUs to submit their pro forma short-term contracts as amendments to their 2009 RPS Procurement Plans within 14 days from the date of the decision. Pursuant to D.09-06-050 and an extension of time granted by the Commission's Executive Director, on July 17, 2009, SCE filed and served its Third Amended 2009 RPS Procurement Plan, including its very short-term pro forma confirmations and certain other further amended 2009 solicitation materials. As SCE's Third Amended 2009 RPS Procurement Plan was not suspended by the Commission's Executive Director or Energy Division Director by July 24, 2009, SCE used its short-term pro forma confirmations and other further amended 2009 solicitation materials in its 2009 RFP as of that date.

2. Summary of SCE's Assessment of Portfolio Needs

SCE's 2009 RPS Procurement Plan indicated that SCE planned to seek eligible renewable energy resources ("ERRs") to the extent necessary to ensure that SCE meets the overall goal of 20 percent renewables as soon as possible. SCE also noted that it intended to procure based on a High Need Case procurement scenario in order to account for potential project success rates and other contingencies. Furthermore, SCE indicated that it has both a near-term and long-term need for renewable energy, and that SCE's evaluation criteria favor proposals for renewable energy sales from generating facilities with near-term deliveries. SCE also stated its evaluation criteria consider the benefits of projects locating near approved transmission infrastructure, such as the Sunrise Powerlink Transmission Project and Tehachapi Renewable Transmission Project.

SCE's 2009 RFP solicited proposals to supply electric energy, as well as all attributes, including, but not limited to, green attributes, capacity attributes, and resource adequacy benefits from ERRs. SCE solicited standard products, moderately short-term products, and very short-term products. SCE stated that it would consider all timely proposals to sell products to SCE from either a new or existing generating facility that can be certified by the California Energy Commission ("CEC") as an ERR or multiple ERRs. Additionally, SCE noted that if the generating facility is not, or cannot be, fully certified as an ERR, then only the electric energy produced by the renewable fuel will be considered as electric energy produced by an ERR, as determined by the CEC.

SCE's 2009 RPS Procurement Plan included SCE's voluntary 2009 RSC Program, which offered two standard contracts for the purchase of renewable energy from facilities located within the CAISO-controlled grid with capacities of (1) not-greater-than 5 MW and (2) greater than 5 MW but not-greater-than 20 MW. Both contracts were based on SCE's 2009 Pro Forma Renewable Power Purchase and Sale Agreement, although the not-greater-than 5 MW contract lowered the requirements for development security and removed the requirements for performance assurance deposits.

SCE filed its 2010 RPS Procurement Plan on December 18, 2009. Subsequently, on April 9, 2010 and June 17, 2010, SCE filed motions to amend its 2010 RPS Procurement Plan, which included amended versions of the 2010 RPS Procurement Plan as attachments. As amended, SCE's 2010 RPS Procurement Plan noted that SCE planned to initiate a 2010 RSC Program with a goal of 250 MW. SCE also stated that it would award contracts based on a request for offers ("RFO"). The Commission has not yet acted on SCE's 2010 RPS Procurement Plan.

3. The RSC Contracts Conform to SCE's Portfolio Needs

Although the RSC Contracts are separate and apart from the agreements executed as a result of SCE's annual solicitation, the RSC Contracts fall within the criteria identified in SCE's 2009 and 2010 RPS Procurement Plans, are expected to contribute significantly toward achievement of SCE's RPS procurement goals, and are consistent with SCE's portfolio needs. Specifically, the 20 RSC projects satisfy SCE's need for eligible renewable energy with a total capacity of 239 MW over a 20-year term. Moreover, the RSC Contracts satisfy SCE's locational preferences and delivery requirements.

4. The RSC Contracts Meet the Project Characteristics for SCE's 2009 RPS Solicitation

SCE's 2009 RFP requested proposals with a minimum capacity of 1.5 MW. As discussed above, SCE preferred proposals for renewable energy sales from generating facilities with near-term deliveries. SCE also considered the benefits of projects locating near approved transmission infrastructure, such as the Sunrise Powerlink Transmission Project and Tehachapi Renewable Transmission Project.

SCE's locational preferences included: (1) California or (2) outside California if the seller complies with all requirements pertaining to "Out-of-State Facilities" as set forth in the CEC RPS Eligibility Guidebook. SCE stated that it prefers in-state facilities.

Additionally, SCE indicated that the delivery point for generating facilities interconnected to the CAISO Control Area must be: (1) the point where the generating facility connects to the CAISO controlled grid if SCE is the scheduling coordinator; or (2) at a point to be determined by SCE. For generating facilities interconnected outside the CAISO Control Area, SCE stated the delivery point must be: (1) the intertie point where seller's transmission provider ties to the CAISO Control Area and seller's scheduling coordinator schedules energy to SCE, as scheduling coordinator within the CAISO Control Area, via an Inter-SC Trade (also known as a scheduling coordinator-to-scheduling coordinator trade); (2) a liquid power trading hub or hubs outside of the CAISO Control Area (e.g., Mid-Columbia); (3) at the generating facility's first point of interconnection with the respective transmission provider's transmission grid, provided, however, that seller has (or will have) firm transmission rights to a liquid trading hub or CAISO for the duration of the term of the agreement that is acceptable to SCE; or (4) at a point to be determined by SCE.

Although the RSC Contracts were not part of the 2009 RPS solicitation, they meet all project characteristics for SCE's 2009 RFP. Specifically, all of the RSC projects are located in California, deliver to the CAISO-controlled grid, and commence operation within three years from CPUC approval of the RSC Contracts. The RSC Contracts meet SCE's near-term and long-term need for RPS-eligible energy and contribute significantly to the State's RPS goals.

B. The RSC Contracts Comply With the Commission's Decisions on Bilateral Contracting

In D.06-10-019, the Commission held that LSEs may enter into bilateral contracts with RPS-eligible generators, as long as the contracts are at least one month in duration. The Commission stated that IOUs' bilateral RPS contracts must be submitted to the Commission for approval by advice letter, and that bilateral RPS contracts are not eligible for supplemental energy payments.[6] In addition, the Commission held that while bilateral contracts are not subject to the MPR, they must be reasonable.

In D.09-06-050, the Commission held that bilateral contracts should be reviewed according to the same processes and standards as contracts that come through a solicitation. Additionally, the Commission found that the MPR should be used as a price benchmark for the evaluation of long-term bilateral contracts. The Commission also held that the contract review standards and processes set out in D.09-06-050 for very short-term contracts and moderately short-term contracts govern both bilateral contracts and contracts that are the result of a solicitation.

As discussed throughout this Advice Letter, the RSC Contracts comply with the requirements of D.06-10-019 and D.09-06-050. In particular, the RSC Contracts are all at least one month in duration and SCE is submitting the contracts for approval via an advice letter. The RSC Contracts are also reasonable based on the same review standards and processes applicable to solicitation contracts as set forth in D.09-06-050. As discussed in more detail below and in the confidential appendices, a least-cost/best-fit ("LCBF") analysis demonstrates that the RSC contracts are reasonable.

The RSC Contracts were pursued through the 2010 RSC Program, which was designed to provide smaller renewable projects with opportunities to contribute to the State's RPS goals. SCE voluntarily initiated the RSC Program in 2007 (then called the "Biomass Program") to support then-Governor Arnold Schwarzenegger's goal to promote energy production from biomass fuel sources.[7] Through this program, SCE has sought to remove some of the barriers that smaller projects may have had when participating in SCE's annual solicitations and increase opportunities for such projects to execute contracts with SCE. In 2009, SCE made the RSC Program available to any facility with capacity of 20 MW or less that meets the ERR certification criteria established by the CEC.

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[6] Supplemental energy payments were eliminated under Senate Bill ("SB") 1036. Pursuant to SB 1036, the Commission now approves above-market funds for RPS contracts.

[7] *See* Executive Order S-06-06.

In D.09-06-018, the Commission accepted SCE's 2009 RSC Program as part of SCE's 2009 RPS Procurement Plan, although it reached no judgment on the standard contracts. The Commission also recognized SCE's initiative and innovation with its RSC Program. The Commission approved 12 contracts executed through the 2009 RSC Program in Resolution E-4359.

The 2009 RSC Program offered standardized contracts for projects up to 20 MW priced at the MPR. Applicants submitted applications to the program and were accepted on a first-come-first-served basis until the 250 MW program cap was satisfied. As indicated in SCE's 2010 RPS Procurement Plan, for the 2010 RSC Program, SCE continued to utilize standardized contracts for projects up to 20 MW; however, SCE conducted a competitive solicitation.[8] SCE utilized a reverse auction for the solicitation. All interested parties were allowed to comment on the pro forma contract and SCE incorporated many suggested changes prior to accepting offers. Project offers were submitted by offerors at a bid price they determined. Projects were then ranked by levelized price and selected from lowest to highest levelized price up to the 250 MW program cap.[9]

In D.10-12-048, the Commission adopted the Renewable Auction Mechanism ("RAM"), which is a Commission-mandated program requiring all IOUs to provide a standardized procurement process for projects up to 20 MW in size. Per D.10-12-048, SCE is required to discontinue the RSC Program going forward to conform to the framework of the RAM, but Commission-approved contracts executed under SCE's 2010 RSC Program will count towards the capacity cap set by D.10-12--048.

C. Least Cost Best Fit ("LCBF") Methodology and Evaluation

As explained above, SCE issued its 2009 RFP on June 29, 2009 in compliance with D.09-06-018 and SCE's Commission-approved solicitation materials. On July 24, 2009, SCE expanded its 2009 RFP to include very short-term and moderately short-term products and very short-term pro forma confirmations pursuant to D.09-06-050. In accordance with SCE's Commission-approved solicitation materials, sellers were required to submit their proposals in response to SCE's 2009 RFP on August 21, 2009. SCE submitted its 2009 Solicitation Short List Report to the Commission on December 4, 2009.

SCE evaluates and ranks proposals based on LCBF criteria that comply with criteria set forth by the Commission in D.03-06-071 and D.04-07-029 (the "LCBF Decisions"). The LCBF analysis evaluates both quantitative and qualitative aspects of each proposal to estimate its value to SCE's customers and its relative value in comparison to other proposals. The LCBF analysis was used to evaluate the proposals SCE received in its

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[8] As stated above, the Commission has not yet acted on SCE's 2010 RPS Procurement Plan.

[9] For a detailed explanation of the competitive solicitation procedures for the 2010 RSC Program, see Appendix C.

2009 RPS solicitation.[10] SCE applied these criteria to the proposals received in its 2009 solicitation in order to establish a "short list" of proposals from sellers with whom SCE would engage in contract discussions.

While assumptions and methodologies have evolved slightly over time, the basic components of SCE's evaluation and selection criteria and process for RPS contracts were established by the Commission's LCBF Decisions. Consistent with those LCBF Decisions, the three main steps undertaken by SCE are: (i) initial data gathering and validation, (ii) a quantitative assessment of proposals, and (iii) adjustments to selection based on proposals' qualitative attributes.

Prior to receiving proposals, SCE finalizes major assumptions and methodologies that drive valuation, including power and gas price forecasts, existing and forecast resource portfolio, and capacity value forecast. Other assumptions, such as the Transmission Ranking Cost Report ("TRCR"), are filed with the Commission for approval prior to the release of solicitation materials.

Once proposals are received, SCE begins an initial review for completeness and conformity with the solicitation protocol. The review includes an initial screen for required submission criteria such as conforming delivery point, minimum project size, and submission of particular proposal package elements. Sellers lacking in any of these items are allowed a cure period to remedy any deficiencies. Following this initial screen, SCE conducts an additional review to determine the reasonableness of proposal parameters such as generation profiles and capacity factors. SCE works directly with sellers to resolve any issues and ensure data is ready for evaluation.

After these reviews, SCE performs a quantitative assessment of each proposal individually and subsequently ranks them based on the proposal's benefit and cost relationship. Specifically, the total benefits and total costs are used to calculate the net levelized cost or "renewable premium" per each complete and conforming proposal. Benefits are comprised of separate capacity and energy components, while costs include the contract payments, integration costs, transmission cost, and debt equivalence. SCE discounts the annual benefit and cost streams to a common base year. The result of the quantitative analysis is a merit-order ranking of all complete and conforming proposals' renewable premiums that helps define the preliminary short list.

In parallel with the quantitative analysis, SCE conducts an in-depth assessment of each proposal's qualitative attributes. This analysis utilizes the Commission's prescribed Project Viability Calculator to assess certain factors including the company/development team, technology, and development milestones. Additional attributes such as transmission area/cluster, seller concentration, portfolio fit of commercial on-line date, project size, and dispatchability and curtailability are also considered in the qualitative analysis. These qualitative attributes are then considered to either eliminate non-viable

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[10] SCE has compared the RSC Contracts to the proposals received in its 2009 RPS solicitation since that was the most recent information available to SCE at the time the RSC Contracts were negotiated and executed. Therefore, SCE discusses its LCBF methodology for the 2009 solicitation in this Advice Letter.

proposals or add projects with high viability to the final short list of proposals, or to determine tie-breakers, if any.

Following its analysis, SCE consults with its Procurement Review Group ("PRG") regarding the final short list and specific evaluation criteria. Whether a proposal selected through this process results in an executed contract depends on the outcome of negotiations between SCE and sellers. Periodically, SCE updates the PRG regarding the progress of negotiations. SCE also consults with its PRG prior to the execution of any successfully negotiated contracts. Subsequently, SCE executes contracts and submits them to the Commission for approval via advice letter filings.

A complete discussion of SCE's RPS Proposal Evaluation and Selection Process and Criteria is provided in Appendix F.

The RSC Contracts were executed as part of SCE's RSC Program and not an SCE solicitation. However, SCE performed an LCBF evaluation of the RSC Contracts in comparison to the proposals SCE received in its 2009 RPS solicitation in accordance with Resolution E-4199 and D.09-06-050. Details regarding the LCBF analysis of the RSC Contracts are provided in Appendix A.

D. <u>Compliance with Standard Terms and Conditions</u>

In D.04-06-014, the Commission established a number of "modifiable" and "non-modifiable" standard terms and conditions to be used by LSEs when contracting for RPS-eligible resources. In D.07-11-025, the Commission reduced the number of "non-modifiable" terms to the following four terms: (1) "CPUC Approval;" (2) "RECs and Green Attributes;" (3) "Eligibility;" and (4) "Applicable Law." The remaining "non-modifiable" terms were converted to "modifiable." In D.08-04-009, the Commission compiled the standard terms and conditions in one document and deleted the "modifiable" standard term and condition on supplemental energy payments from the standard terms and conditions. In D.08-08-028, the Commission revised the "non-modifiable" "RECs and Green Attributes" standard term and condition.

The RSC Contracts include the four "non-modifiable" terms identified above without change.

Pursuant to D.04-06-014, D.07-11-025, and D.08-04-009, SCE is permitted to modify the "modifiable" terms. With the RSC Program standard contracts, few, if any, of the terms in SCE's pro forma RSC PPAs are modified during the negotiation process with the sellers. Accordingly, the RSC Contracts contain only limited modifications necessary to accommodate project specific requirements. These modifications include the same principles and serve the same purpose as the standard terms, and are consistent with the law and government regulations. Thus, the modifications contained in the RSC Contracts are permissible.

In D.10-03-021, as modified by D.11-01-025, the Commission established two additional "non-modifiable" terms relating to renewable energy credits. As the RSC Contracts were already executed when D.11-01-025 was issued, they do not currently include the additional standard terms. SCE is currently working to amend the contracts pursuant to D.11-01-025.

E. Unbundled Renewable Energy Credit ("REC") Transactions

SCE is purchasing bundled RPS-eligible energy and green attributes under the RSC Contracts. Moreover, the RSC projects all have a first point of interconnection with a California balancing authority. Accordingly, the RSC Contracts are not unbundled REC transactions under D.10-03-021, as modified by D.11-01-025.

F. Minimum Quantity

In D.07-05-028, the Commission held that, beginning in 2007, each LSE obligated under the RPS program must enter into long-term contracts[11] or short-term contracts with new facilities[12] for energy deliveries equivalent to 0.25% of that LSE's prior year's retail sales, in order to be able to count for RPS compliance energy deliveries from short-term contracts with existing facilities. The Commission also ruled that RPS-obligated LSEs may carry forward contracted energy in long-term contracts and short-term contracts with new facilities that is in excess of the 0.25% requirement in the year such contracts are signed, to be used for compliance for the minimum-quantity requirement in future years.

The 20 RSC Contracts are long-term PPAs associated with new generation facilities. Therefore, the minimum-quantity requirement does not apply.

G. MPR

The RSC Contracts have levelized prices below the 2009 MPRs, which are the most current MPRs available. The RSC Contracts, moreover, have no firming and shaping costs, so the total prices remain below the 2009 MPRs.

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[11] Long-term contracts are contracts of at least 10 years duration. *See* Cal. Pub. Util. Code § 399.14.

[12] New facilities are facilities that commenced commercial operations on or after January 1, 2005. *See* Cal. Pub. Util. Code § 399.14.

H. Above Market Funds ("AMFs")

The RSC Contracts have levelized prices below the 2009 MPRs. Therefore, no AMFs are required based on the energy prices for the RSC Contracts in comparison to the 2009 MPRs. The AMF Calculators and a summary are included in Appendix G.

I. Interim Emissions Performance Standard

The California Legislature passed Senate Bill ("SB") 1368 on August 31, 2006 and Governor Schwarzenegger signed the bill into law on September 29, 2006. Section 2 of SB 1368 adds Public Utilities Code section 8341(a), which provides that "No load-serving entity or local publicly owned electric utility may enter into a long-term financial commitment unless any baseload generation supplied under the long-term financial commitment complies with the greenhouse gases emission performance standard established by the commission, pursuant to subdivision (d)."[13]

In order to institute the provisions of SB 1368, the Commission instituted Rulemaking 06-04-009. This proceeding resulted in the establishment of a greenhouse gas ("GHG") emissions performance standard ("EPS"), for carbon dioxide ("CO_2"). The Commission noted, "SB 1368 establishes a minimum performance requirement for any long-term financial commitment for baseload generation that will be supplying power to California ratepayers. The new law establishes that the GHG emissions rates for these facilities must be no higher than the GHG emissions rate of a combined-cycle gas turbine (CCGT) power plant."[14]

The decision further explains:

> SB 1368 describes what types of generation and financial commitments will be subject to the EPS ("covered procurements"). Under SB 1368, the EPS applies to "baseload generation," but the requirement to comply with it is triggered only if there is a "long-term financial commitment" by an LSE. The statute defines baseload generation as "electricity generation from a power plant that is designed and intended to provide electricity at an annualized plant capacity factor of at least 60%." . . . For baseload generation procured under contract, there is a long-term commitment when the LSE enters into "a new or renewed contract with a term of five or more years."[15]

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[13] Cal. Pub. Util. Code § 8341(a).

[14] D.07-01-039 at 2-3.

[15] *Id*. at 4.

The RSC Contracts are exempt from EPS regulations because they have expected annualized capacity factor ranging from 23 percent to 32 percent, well below the threshold baseload capacity factor of 60 percent, above which the EPS rules would apply.

J. PRG Participation

SCE's PRG was formed on or around September 10, 2002. Participants include representatives from the Commission's Energy and Legal Divisions, the Division of Ratepayer Advocates, The Utility Reform Network, the Natural Resources Defense Council, California Utility Employees, the Union of Concerned Scientists and the California Department of Water Resources.

Offers for the 2010 RSC Program were received September 15, 2010. On September 29, 2010, SCE briefed the PRG concerning the 2010 RSC Program. On November 10, 2010, SCE updated the PRG concerning the status of the RSC Contracts, which were then executed on November 15, 2010.

K. Independent Evaluator ("IE")

The IE for the 2010 RSC Program was Merrimack Energy Group, Inc. The IE joined and contributed to a number of conference calls and negotiation sessions. In addition, the IE reviewed email traffic, the draft pro forma RSC contract, and other documents exchanged by the parties. The IE also participated in the PRG review of the RSC Contracts on November 10, 2010. The IE Report is included as Appendix C.

III. PROJECT DEVELOPMENT STATUS

A. Company / Development Team

The developers who participate in the RSC Program have varying degrees of experience in the field of renewable energy project development. Specific information on the six developers for the 20 RSC Contracts is provided below.[16]

- Amonix, Inc. ("Amonix"): Amonix, the parent company of Blythe Solar Power Generation Station, 1 LLC, Garnet Solar Power Generation Station, 1 LLC, Littlerock Solar Power Generation Station, 1 LLC, and Lucerne Solar Power Generation Station, 1 LLC, is a leading designer and manufacturer of concentrated photovoltaic ("CPV") solar power systems. Amonix CPV technology has been operated at 16 locations throughout the Southwestern United States, and in Spain. Founded in 1989, Amonix is headquartered in Seal Beach, California, with additional facilities in Torrance, California. Amonix's executive team includes:

[16] This information is based on documents submitted by the developers to SCE, and has not all been independently verified by SCE.

- Brian Robertson, CEO. Previously, Mr. Robertson was co-founder and former President of SunEdison, where he oversaw the construction, financing, and operation of over 150 commercial, industrial, and utility-scale solar PV projects.
- Guy Blanchard, Senior Vice President, Corporate Development. Mr. Blanchard has extensive capital markets experience with a focus on energy and renewable energy investments.
- Matthew Meares, Director of Project Finance. Mr. Meares has closed over $382 million in solar transactions and over $1 billion in wind project financings.

Amonix has substantial prior experience both developing its own projects using its CPV technology and supplying its CPV technology with value-added support for deployment by other project developers. Amonix has supplied its technology to nearly 75 percent of the world's CPV installations, including five projects of 1 MW to 5.8 MW that are operating in Spain, and 4 projects smaller than 1 MW operating in the United States. Amonix is co-developing its RSC projects with one of the largest heavy civil construction contractors in the United States

- Clear Peak Energy, Inc. ("Clear Peak"): Clear Peak is a publicly traded Nevada Corporation organized to develop and operate clean solar electric power plants incorporating proven, lower-cost, PV technology. Clear Peak partnered with Aubrey Silvey Enterprises, Inc. ("Silvey"), which will serve as general contractor for the proposed project.

  Silvey is a global leader of technical, project, and operational support services and provides comprehensive services to the power industry in all aspects of renewable project execution including civil engineering and design, electrical engineering and design, construction, interconnection, commissioning and maintenance. Silvey has nearly 40 years of history with large utility scale power and renewable energy projects for major clients throughout the United States that include utilities such as SCE, Los Angeles Department of Water and Power, Pacific Gas and Electric Company, and San Diego Gas & Electric Company.

  Silvey's Renewable Energy Division develops renewable energy-specific projects throughout the United States. The division has successfully completed or is currently working on over 275 MW of wind power generation projects since 2007, with 120 MW currently in progress. In addition, Silvey's staff has engineered and designed 38 MW of solar PV projects since 2008. Silvey's current and recent projects include balance of plant services for wind projects in states including Oregon, Utah and Idaho.

- Foresight Renewables, LLC ("Foresight"): Foresight, the parent company of Tropico LLC and Nicolis LLC, has nearly 3,500 MW under development through Foresight Wind and over 200 MW through Foresight Solar. Foresight's founder and CEO, Warren Byrne, has over 20 years experience in power development, having started his career at Caithness Energy in 1987. Several Vice Presidents also have over 20 years of experience, including Paul Andrae, former director of transmission and distribution development for PNM and John Fedorko, former Senior Vice President for Airtricity. Foresight's principals have played lead roles in the development of over 1,235 MW of operating electricity projects. The projects include Foresight Wind's 100 MW High Lonesome Mesa wind project in New Mexico, currently owned by Edison Mission Wind, and Airtricity's 900 MW Roscoe project, now owned by E.On.

- juwi solar Inc. ("juwi solar"): juwi solar, the parent company of Sierra View Solar V LLC and Sierra View Solar IV LLC, is a developer and turnkey engineering, procurement, and construction contractor of solar power plants throughout North America. Its majority shareholder is juwi Holding AG, which ranks among Europe's leading renewable energy companies. The juwi solar team, with combined experience of over 75 years, has developed, financed and built energy projects involving wind, hydropower, solar PV, geothermal, combined-cycle and coal-fired technologies, the aggregate of which have a generation capacity in the thousands of megawatts. Specifically, juwi solar has been involved in the development, design, construction and operation of more than 1,000 PV projects, with a current total generation capacity of 300 MW. Its project experience covers the full range of project development activities, including development, design engineering, energy generation modeling, project permitting, project finance, legal support, project construction, commissioning, operation and maintenance.

  Key members of the juwi solar team who will implement the projects include:

  - Michael Martin, Managing Director. Mr. Martin joined juwi solar in April of 2008. He has over 20 years experience that includes senior level finance and development positions for renewable energy generation companies. At Morgan Stanley, he was involved in the development and execution of over $3 billion in equity and debt-related financings. At Deutsche Bank, he covered the Latin American Electric Utilities sector. At Econergy International PLC, he managed a pipeline of wind, hydro and solar projects through development and construction stages in the United States and Latin America.

  - Steve Ihnot, Chief Financial Officer. Mr. Ihnot has 15 years of experience in the electric power business in various roles in finance and development both in the United States and internationally.

  - Scott Leach, Business Development Associate. Mr. Leach has seven years of experience working within the business and financial structures of renewable energy projects. In 2009, he helped lead the development of over 45 MW of solar energy generation facilities that are currently in operation or under construction, including the 12 MW Wyandot Solar project (Ohio), 16 MW Jacksonville Solar project (Florida) and 16 MW Blue Wing Solar project (Texas).

  There are five operating solar PV projects greater than 1 MW built by the juwi solar team in the United States.

- <u>Recurrent Energy:</u> Recurrent Energy, the parent company of RE Columbia 3 LLC and RE Columbia Two, LLC, is a leading solar development company. Recurrent Energy was venture capital funded and was recently acquired by Sharp Corporation. Recurrent Energy has a portfolio of over 370 MW of contracted projects and an established development pipeline of 2 GW. Four projects greater than 1 MW are operating (26 MW total).

  Recurrent Energy's leadership team brings more than 100 years of solar and energy project experience with various companies. Specific to the development team, Recurrent Energy has over 30 years combined experience in conventional and renewable power development. Key leaders of the development team are discussed below.

  - Sheldon Kimber, Senior Vice President, Development. Mr. Kimber leads all North American project development, expansion, and origination activities. Formerly the Vice President of Finance at Recurrent Energy, he was instrumental in developing and negotiating the company's existing projects, fundraising efforts, and joint venture agreements. Previously, he spent five years at Calpine Corporation, working on gas-fired power projects and power purchase agreements with large energy customers. He also worked as an investment banker at Goldman Sachs, and in Accenture's strategy consulting practice.
  - Tiffany Elliott, Vice President, Origination and Structuring. Ms. Elliott has over 11 years industry experience leading the origination and structuring of tailored commodity transactions. Prior to joining Recurrent Energy, she served as Executive Director at Amerex Energy Consulting, where she was engaged by several renewable companies developing solar, wind, and biomass projects. She was a Director at Citigroup Energy where she was responsible for the execution of structured power and natural gas. She worked at Calpine Energy Services for over 6 years where she structured, originated and subsequently monetized several profitable transactions.
  - André DeVilbiss, Director, West Region Development. Mr. DeVilbiss has over eight years of financial transaction experience, and three years experience specific to solar development at Recurrent Energy. He has been involved in the development of the company's California projects as well as the Arizona projects which are slated to come on-line in 2011. He is responsible for identifying sites, obtaining permits and interconnection agreements, and negotiating PPAs. Prior to Recurrent Energy, he was a Vice President at Bank of America Securities LLC.

- <u>Silverado Power ("Silverado"):</u> Silverado, the parent company of American Solar Greenworks, LLC, Central Antelope Dry Ranch B, LLC, Central Antelope Dry Ranch C, LLC, Lancaster Dry Farm Ranch B, LLC, Lancaster WAD B, LLC, North Lancaster Ranch, LLC, Sierra Solar Greenworks, LLC, Victor Dry Farm Ranch A, LLC, and Victor Dry Farm Ranch B, LLC, is a joint venture between a group of industry veterans and Martifer Solar, a large European energy and infrastructure company. The Silverado Power team has over 50 years of collective development experience for over 500 MW of solar development, financing and construction, including industry-leading green field utility scale and commercial projects.

Silverado's experienced team is designed to provide solutions to the biggest challenges facing renewable energy development, typically permitting, interconnection, and financing. The team includes utility engineers, land development professionals, and capital finance experts.

The Martifer Group is a multinational infrastructure company based in Portugal, with a focus on construction and renewable energy. Martifer was founded in 1990, and presently has more than 4,000 employees. The group's holding company, Martifer SGPS, SA (Euronext: MAR) has been publicly traded on the Euronext Lisbon since June 2007.

Martifer Solar is a wholly owned subsidiary of the Martifer Group. The core business of Martifer Solar is to offer turnkey PV solutions, including development, engineering services, module and solar tracker production, facility construction, operation and maintenance. The company operates in 16 countries and has constructed more than 100 MW in PV energy worldwide. Martifer's list of "finished installations and ongoing projects" since 2007 shows 27 projects 1 MW or larger.

Three of the key principals of Silverado are listed below.

- John Cheney, CEO and co-founder of Silverado. Mr. Cheney has founded and served as CEO or Managing Partner of several companies including Varitel Video, RTE One, Avenue Technologies and RocketFiber. In his previous role as Vice President of Sales and Business Development for MMA Renewable Ventures, he helped turn the company into the largest financier of solar PV installations in the United States. After completing $450 Million of solar installations across the country, MMA Renewable Ventures was sold to FRV of Spain.
- Hans Isern, Vice President Engineering. Mr. Isern brings to Silverado a combination of electrical energy industry experience across all stages of power plant development. He has led teams in diverse roles including utility engineering, power trading, regulatory affairs, and generation development and finance. Prior to his current role, he led development in Southern California for Recurrent Energy. He created a 350 MW pipeline, led negotiations for 50 MW of solar projects with SCE, and oversaw interconnection and permitting processes for a wide range of projects.
- Jim Howell, Vice President Development. Mr. Howell has an extensive background in asset creation through structuring and contract negotiations. He is responsible for Silverado's regional development strategies, resource deployment and policy for entering new renewable energy markets. He also came to Silverado after a successful stint with Recurrent Energy.

B. Technology

1. Technology Type and Level of Technology Maturity

All of the RSC projects will utilize proven and mature solar PV technology. Solar PV technology is well-established and has been supplying a substantial amount of renewable energy to SCE and other California LSEs for several years

2. Quality of Renewable Resource

The RSC projects are located throughout Southern California, an area well-recognized for its robust solar resources as demonstrated by several sources of solar generation throughout the region.

SCE believes that each RSC project will be able meet the terms of the contract given SCE's independent understanding of the quality of the renewable resources.

3. Other Resources Required

The RSC projects will require water for use in ancillary road maintenance or blade/panel cleaning. The water will be provided by local water providers. SCE expects that water used for the site roads will be absorbed into the ground and back into the natural underground aquifers, where it will be recycled naturally.

C. Development Milestones

1. Site Control

Each RSC project has secured 100% site control to support its respective project including full site and substation access. Additional information regarding site control is included in Appendix A.

2. Equipment Procurement

Each RSC Contract is at a different stage of procuring equipment. Most RSC projects are negotiating contracts with suppliers for equipment. RSC Contracts are required to have a commercial operation date no later than three years after CPUC approval of this advice letter. This requirement allows enough time for each RSC project to determine its equipment needs and procure them from a supplier before the start-up deadline. As discussed above, each developer has many years of development experience and a good history in its ability to procure equipment.

Specific information on the equipment procurement of the six developers for the 20 RSC Contracts is provided in Appendix A.

3. Permitting / Certifications Status

Information regarding permitting/certifications status is included in Appendix A.

4. Production Tax Credit ("PTC") / Investment Tax Credit ("ITC")

Information regarding PTCs and ITCs is provided in Appendix A.

5. Transmission

Several projects will incur costs for substation upgrades or construction in order to interconnect to the distribution system. The final gen-tie and network upgrades and the related costs required to interconnect the RSC projects are not yet known. It is not known how issues relating to other generating facility projects in the transmission queue may affect the RSC projects.

All transmission-related upgrades must be completed to allow the RSC projects to come on-line within three years of CPUC approval. If there is a delay in completing the necessary transmission-related upgrades caused only by the CAISO or the transmission provider, the commercial operation deadline shall be extended on a day-for-day basis until completion.

Additional information regarding transmission is provided in Appendix A.

D. Financing Plan

Specific information on the financing plans of the six developers for the 20 RSC Contracts is provided in Appendix A.

IV. CONTINGENCIES AND MILESTONES

Specific information regarding the terms of the RSC Contracts can be found in Appendices D and H.1 through AA.2.

V. REQUEST FOR COMMISSION APPROVAL

The terms of the RSC Contracts are conditioned on the occurrence of "CPUC Approval," as it is defined in the RSC Contracts. To satisfy that condition with respect to the RSC Contracts, SCE requests that the Commission issue a resolution no later than July 29, 2011, containing:

1. Approval of the RSC Contracts in their entirety;

2. A finding that any electric energy sold or dedicated to SCE pursuant to the RSC Contracts constitutes procurement by SCE from an ERR for the purpose of determining SCE's compliance with the RPS Legislation or other applicable law concerning the procurement of electric energy from renewable energy resources;

3. A finding that all procurement under the RSC Contracts counts, in full and without condition, toward any annual procurement target established by the RPS Legislation or the Commission that is applicable to SCE;

4. A finding that all procurement under the RSC Contracts counts, in full and without condition, toward any incremental procurement target established by the RPS Legislation or the Commission that is applicable to SCE;

5. A finding that all procurement under the RSC Contracts counts, in full and without condition, towards the requirement in the RPS Legislation that SCE procure 20% (or such other percentage as may be established by law) of its retail sales from ERRs by 2010 (or such other date as may be established by law);

6. A finding that the RSC Contracts, and SCE's entry into the RSC Contracts, are reasonable and prudent for all purposes, including, but not limited to, recovery in rates of payments made pursuant to the RSC Contracts, subject only to further review with respect to the reasonableness of SCE's administration of the RSC Contracts;

7. A finding that all procurement under the RSC Contracts counts, in full and without condition, towards SCE's capacity cap under the RAM pursuant to D.10-12-048; and

8. Any other and further relief as the Commission finds just and reasonable.

VI. TIER DESIGNATION

Pursuant to D.07-01-024, Energy Industry Rule 5.3, SCE submits this Advice Letter with a Tier 3 designation (effective after Commission approval).

VII. EFFECTIVE DATE

This Advice Letter will become effective July 29, 2011.

VIII. NOTICE

Anyone wishing to protest this Advice Letter may do so by letter via U.S. Mail, facsimile or electronically, any of which must be received by the Energy Division and SCE no later than 20 days after the date of this Advice Letter. Protests should be mailed to:

Akbar Jazayeri
Vice President of Regulatory Operations
Southern California Edison Company
2244 Walnut Grove Avenue, Quad 3D
Rosemead, California 91770
Facsimile: (626) 302-4829
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Bruce Foster
Senior Vice President, Regulatory Affairs
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With a copy to:

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Facsimile: (626) 302-1935
E-mail: Joni.Templeton@sce.com

There are no restrictions on who may file a protest, but the protest shall set forth specifically the grounds upon which it is based and shall be submitted expeditiously.

In accordance with Section 4 of GO 96-B, SCE is furnishing copies of this Advice Letter to the interested parties shown on the attached R.08-08-009, R.06-02-012, and GO 96-B service lists. Address change requests to the GO 96-B service list should be directed to AdviceTariffManager@sce.com or (626) 302-2930. For changes to any other service list, please contact the Commission's Process Office at ProcessOffice@cpuc.ca.gov or (415) 703-2021.

Further, in accordance with Public Utilities Code section 491, notice to the public is hereby given by filing and keeping this Advice Letter at SCE's corporate headquarters. To view other SCE advice letters filed with the Commission, log on to SCE's web site at http://www.sce.com/AboutSCE/Regulatory/adviceletters/.

All questions concerning this Advice Letter should be directed to Laura Genao at Laura.Genao@sce.com or (626) 302-6842.

Southern California Edison Company

Akbar Jazayeri

AJ/na
Enclosures

CALIFORNIA PUBLIC UTILITIES COMMISSION

ADVICE LETTER FILING SUMMARY
ENERGY UTILITY

MUST BE COMPLETED BY UTILITY (Attach additional pages as needed)

Company name/CPUC Utility No.: Southern California Edison Company (U 338-E)

Utility type:

☑ ELC ☐ GAS

☐ PLC ☐ HEAT ☐ WATER

Contact Person: James Yee

Phone #: (626) 302-2509

E-mail: James.Yee@sce.com

E-mail Disposition Notice to: AdviceTariffManager@sce.com

EXPLANATION OF UTILITY TYPE

ELC = Electric GAS = Gas
PLC = Pipeline HEAT = Heat WATER = Water

(Date Filed/ Received Stamp by CPUC)

Advice Letter (AL) #: 2547-E Tier Designation: 3

Subject of AL: Submission of Contracts for Procurement of Renewable Energy Resulting From Renewables Standard Contracts Program

Keywords (choose from CPUC listing): Compliance, Contracts, Procurement

AL filing type: ☐ Monthly ☐ Quarterly ☐ Annual ☑ One-Time ☐ Other

If AL filed in compliance with a Commission order, indicate relevant Decision/Resolution #:

Does AL replace a withdrawn or rejected AL? If so, identify the prior AL:

Summarize differences between the AL and the prior withdrawn or rejected AL[1]:

Confidential treatment requested? ☑ Yes ☐ No

If yes, specification of confidential information: See Appendix CC
Confidential information will be made available to appropriate parties who execute a nondisclosure agreement.
Name and contact information to request nondisclosure agreement/access to confidential information:

Joni Templeton, Law Department, at (626) 302-6210 or Joni.Templeton@sce.com.

Resolution Required? ☑ Yes ☐ No

Requested effective date: 7/29/11 No. of tariff sheets: -0-

Estimated system annual revenue effect: (%):

Estimated system average rate effect (%):

When rates are affected by AL, include attachment in AL showing average rate effects on customer classes (residential, small commercial, large C/I, agricultural, lighting).

Tariff schedules affected: None

Service affected and changes proposed[1]:

Pending advice letters that revise the same tariff sheets:

[1] Discuss in AL if more space is needed.

Protests and all other correspondence regarding this AL are due no later than 20 days after the date of this filing, unless otherwise authorized by the Commission, and shall be sent to:

CPUC, Energy Division
Attention: Tariff Unit
505 Van Ness Ave.,
San Francisco, CA 94102
jnj@cpuc.ca.gov and mas@cpuc.ca.gov

Akbar Jazayeri
Vice President of Regulatory Operations
Southern California Edison Company
2244 Walnut Grove Avenue
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Facsimile: (626) 302-4829
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Bruce Foster
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Marc Ulrich
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With a copy to:

Joni A. Templeton
Attorney
Southern California Edison Company
2244 Walnut Grove Avenue, 3rd Floor
Rosemead, California 91770
Facsimile: (626) 302-1935
E-mail: Joni.Templeton@sce.com

Confidential Appendix A

Consistency with Commission Decisions and Rules and Project Development Status

Confidential Protected Materials – Public Disclosure Prohibited

Confidential Appendix B

2010 RSC Program Solicitation Overview and 2009 Solicitation Workpapers

Confidential Protected Materials – Public Disclosure Prohibited

Public Appendix C

Independent Evaluator (IE) Report and Appendix B of IE Report

Southern California Edison Company

2010 Renewable Standard Contracts Program

Request for Offers

Report of

Independent Evaluator

January 2011

Prepared by

Merrimack Energy Group, Inc.

Merrimack

M

Energy

and

New Energy Opportunities, Inc.

Table of Contents

I. Introduction

A. Overview

Southern California Edison Company ("SCE") is seeking approval of 20 power purchase agreements ("PPAs") for the purchase of approximately 567 GWh of estimated energy annually from approximately 239 MW of installed capacity under SCE's 2010 Renewable Standard Contract ("RSC") program. All 20 contracts are for renewable energy produced by solar photovoltaic ("PV") projects.

On August 2, 2010, SCE issued its 2010 Renewable Standard Contracts Program Request for Offers ("2010 RSC RFO"). SCE solicited offers from owners of eligible renewable resource ("ERR") generating facilities not greater than 20 MW in size to supply up to 250 MW of electrical energy, green attributes and resource adequacy benefits under standard power purchase and sale agreements for execution in 2010.[1] SCE's stated goal for the RSC Program was to provide a "standardized procurement process for projects not greater than 20 MW that leads to quick execution relative to other procurement processes."[2]

The 2010 RSC Program was a voluntary initiative of SCE and differed from its 2009 RSC Program in several important respects. First, the 2010 RSC Program was a competitive solicitation—with winning bidders being paid their bid prices. Under the 2009 RSC Program, sellers under the standard contract obtained a predetermined price based on the applicable 2009 Market Price Referent ("MPR"). Second, projects under the 2010 RSC Program must have forecasted commercial operation dates within three years of approval by the California Public Utilities Commission ("CPUC" or "Commission") of the power purchase agreements ("PPAs"). The 2009 RSC Program had no similar requirement. There were also a variety of changes to the terms and conditions of the renewable standard contracts.

[1] Specifically, the product requested was all energy produced by the generating facility, net of Station Use, and all Green Attributes, Capacity Attributes, and Resource Adequacy Benefits (as those terms are defined in the standard contracts).
[2] RFO Participant Instructions (Revision 2—August 16, 2010) at 1, http://asset.sce.com/Documents/Shared/100816_RSC_RFO_ParticipantInstructions.pdf.

Pursuant to regulatory requirements of the Commission, SCE retained Merrimack Energy Group, Inc. ("Merrimack Energy") as the Independent Evaluator ("IE") for the 2010 RSC Program.[3]

This IE report is submitted in conformance to the requirements of the CPUC and is designed to be consistent with the requirements outlined in the CPUC's November 2010 IE Report Template, as adjusted to reflect the particular features of this solicitation.

B. Program Background

The 2010 RSC Program represents an evolution of SCE's voluntary standard contract program over a number of years. In 2007, SCE initiated a biomass generation renewable standard contract program to support Governor Schwarzenegger's plan to promote energy production from biomass fuel sources in California. The program allowed smaller projects the opportunity to execute standard contracts at the MPR price structure then in effect.[4]

The biomass standard contracts program was originally designed to remain open until the earlier of December 31, 2007 or until such time as SCE signed contracts totaling 250 MW. In early 2008, SCE extended the program into 2008 and kept the 250 MW cap in place.

In 2009, SCE proposed that the biomass standard contracts would be available, with some modifications, for all types of ERRs under California's Renewable Portfolio Standard program of up to 20 MW in size. Under the 2009 RSC Program, SCE executed 13 PPAs for the purchase of 458 GWh of estimated energy from 190.3 MW of installed capacity, including amendments to two pre-existing PPAs with landfill gas projects. In March 2010, SCE filed an advice letter seeking approval of these PPAs.[5]

At the time of its filing of its 2010 RPS Procurement Plan in December 2009, SCE was in the process of addressing the proposals under its 2009 RSC Program, which represented, at that time, almost double the program's goal of 250 MW.[6] SCE stated that it was suspending the RSC Program and reviewing options for restarting the program in 2010.[7] In April 2010, SCE amended its 2010 RPS procurement plan to, among other things,

[3]Merrimack Energy also served as IE for SCE's 2009 RSC Program and for the 2009 Renewable Portfolio Standards RFP. As before, New Energy Opportunities, Inc. has served as a subcontractor to Merrimack Energy.

[4] In 2007 and 2008, SCE offered three different contracts which varied depending on the size of the generating facility. These contracts applied to facilities with capacities of less than 1 MW, 1 MW through 5 MW, or greater than 5 MW through 20 MW. All three contracts were offered to RPS-eligible biomass resources for terms of 10, 15, and 20 years, and at an energy price set at the MPR, multiplied by energy allocation factors for SCE's TOU periods.

[5] Submission of Contracts for Procurement of Renewable Energy Resulting from Renewable Standard Contracts, Advice 2457-E (March 29, 2010), as amended by Advice 2457-E-A (June 15, 2010).

[6] SCE's (U 338-E) 2010 RPS Procurement Plan, R. 08-08-009 (December 18, 2009) at 28. In other words, SCE received had received many more proposals for renewable standard contracts at MPR-based rates than the 250 MW allotted for the 2009 RSC program.

[7] *Id.*

provide for a 2010 RSC program based on a RFO process to be conducted twice a year, rather than offering MPR-based energy prices.[8]

C. Launch of the 2010 RSC RFO; Participant Instructions

On July 22, 2010, SCE issued to its email distribution list a notice that it would officially launch the 2010 RSC RFO on August 2, 2010 through a posting on its website. SCE also announced that it would be holding a web conference for the RSC RFO on August 10, 2010.

On August 2, 2010, SCE posted on its website the RFO Participant Instructions, an offer template, a draft standard contract for offers from facilities of not more than 20 MW ("RSC20"), a draft standard contract for offers from facilities of not more than 5 MW ("RSC5"), a form non-disclosure agreement, and other pertinent information.[9]

The RFO Participant Instructions, as amended on August 16, 2010, set forth the requirements for prospective Offerors, the evaluation framework, and the schedule for submission of offers, SCE review, execution of PPAs, and submittal of advice letters for CPUC approval.

Participants were allowed to submit offers from ERRs in one or more of the following categories:

- For projects not greater than 5 MW, RSC5;

- For projects not greater than 20 MW, RSC20.

RSC5 and RSC20 contain similar terms and conditions, with a few notable exceptions. RSC5 has a lower development security deposit than RSC20--$30 per kW for intermittent facilities and $60/kW for baseload facilities compared to $60 per kW for intermittent facilities and $90/kW for baseload facilities under RSC20. There is no requirement to post Performance Assurance under RSC5, while Performance Assurance under RSC20 is an average of 5% of total project revenues (the percentage varies by contract year).

Generating facilities associated with all RSC proposals would be subject to the following eligibility and threshold requirements:

- The facility could be new or existing, but an existing facility must be certified by the California Energy Commission as an ERR prior to the offer due date;

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[8] Southern California Edison Company's (U 338-E) Amended 2010 RPS Procurement Plan, R. 08-08-009 (April 9, 2010) at 28-30, See also SCE's Second Amended 2010 RPS Procurement Plan, R. 08-08-009 (June 17, 2010) at 29-30.
[9] These documents, as subsequently, revised, are at http://www.sce.com/EnergyProcurement/renewables/renewables-standard-contracts.htm.

- The facility must be located within the electric power system of the California Independent System Operating Corporation ("CAISO");

- The facility must be scheduled to commence operation within three years from CPUC approval of the RSC.

The standard contracts, once finalized after general opportunity for comment, would not be subject to negotiation, except for changes that are unique to an Offeror's particular project.[10] Offerors could propose contract durations for RSC5 and RSC20 for 10, 15, or 20 years.

Participants were allowed to submit comments on, or proposed revisions to, the pro forma RSCs through August 18, 2010. SCE posted the final pro forma RSCs on September 1, 2010. A web conference was held on September 3, 2010 to review the final pro forma RSCs, including certain changes made by SCE to the RSCs following the receipt of comments.

Evaluation and selection of eligible Offers was to be based on levelized Product Price—i.e., Offers would be ranked from lowest to highest levelized price for each offer and selected based on the levelized price in $/MWh AC—up to a maximum total capacity of 250 MW.[11] Eligible lower-priced Offers would be accepted ahead of eligible higher-priced Offers. SCE also stated that it "reserves the right to evaluate and select offers on other quantitative and qualitative metrics depending on market response."[12]

The deadline for submission of Offers was September 15, 2010. Offers were required to be submitted by email and sent to both SCE and the IE. Offers were required to include an executed Offer Template, including the Revenue Calculator, a redlined RSC with all proposed project-specific changes, and times that the Offeror would be available for a meeting or conference call, if shortlisted, to discuss project-specific terms and conditions to be included in a RSC. SCE stated that it planned to notify each Offeror by email by September 30, 2010 whether or not their Offer had been shortlisted. During October 2010, SCE would work with shortlisted Offerors to finalize RSCs for particular proposed ERRs, with execution of final RSCs by November 15, 2010. SCE indicated that it would submit to the Commission by January 31, 2011 a Tier 3 advice letter seeking approval of the RSCs entered into pursuant to the RSC RFO.

D. Submittal, Evaluation and Selection of Offers; Interaction with the Commission's Renewable Auction Mechanism Decision

Between the time that the RSC RFO was launched and Offers were submitted to SCE, a Proposed Decision was issued by the Commission adopting the Renewable Auction Mechanism ("RAM") proposed by Energy Division. In an August 24, 2010 Proposed

[10] RFO Participant Instructions at 5.
[11] The ranking would be before time-of-delivery price adjustments.
[12] RFO Particpant Instructions at 4-5.

Decision of ALJ Mattson, a mandatory competitive procurement process for renewable resources up to 20 MW in size was described using standardized contracts under which, if made final, SCE would be required to procure approximately 500 MW of renewable resources under long-term contracts.[13] The proposed RAM was similar to SCE's 2010 RSC RFO in certain respects but different in other respects. Of course, one key difference is that RAM was proposed to be a mandatory program, while the RSC Program was a voluntary program initiated by SCE. While SCE had argued that resources procured under the RSC Program should count toward meeting any RAM requirement, this position was not accepted in the Proposed Decision.[14]

On September 8, 2010, a week before bids were due, SCE issued a statement to prospective bidders regarding the potential impact of the proposed RAM decision on the RSC RFO.

> On August 24, the CPUC issued a proposed decision for a new program known as the Renewable Auction Mechanism (RAM). The focus of this program targets the same projects (<20 MW renewable technologies) and includes many of the same features as the current Renewables Standard Contract (RSC) program operated by SCE. The proposed decision, as currently drafted, would have a negative impact on SCE's completion of the current RSC solicitation. SCE will submit comments on the RAM proposed decision as part of the regulatory process with the desired outcome being the continuation of the current RSC solicitation. At this time, SCE will accept offers on September 15 according to schedule. If, however, the RAM proposed decision is not satisfactorily resolved by November 15, then SCE will not execute contracts from this solicitation. In the meantime we will continue with all other RSC solicitation efforts as outlined in the posted RFO Participant Instructions. We will keep RSC participants informed of any changes or updates to the RSC solicitation as the RAM regulatory proceeding evolves. Please feel free to contact the SCE RSC team if you have questions.

On September 15, 2010, SCE received an extremely robust response to the RFO. Details are provided in Confidential Appendix A to this report.

On September 27, 2010, SCE submitted comments to the Commission recommending rejection of the Renewable Auction Mechanism as described in the Proposed Decision.[15] Referring to its launch of the 2010 RSC solicitation, SCE stated:

> Over 350 participants were involved in the 2010 RSC solicitation's bidder's conference. Unfortunately, the release of the PD has already undermined SCE's competitive procurement efforts for the upcoming solicitation. The RAM PD has created an uncertainty in the market over whether the RSC Program will be

[13] Proposed Decision, Decision Adopting the Renewable Auction Mechanism, R. 08-08-009 (August 24, 2010).
[14] Proposed Decision at 103-04.
[15] Comments of Southern California Edison Company on Proposed Decision Adopting the Renewable Auction Mechanism, R. 08-08-009 (September 27, 2010).

> replaced by the RAM. Given that the proposed RAM targets the same market as the RSC Program, SCE would likely terminate its RSC program if the RAM PD is implemented to avoid duplicative efforts directed at providing opportunities for the same segment of the renewable market.[16]

As described more fully in the confidential appendix, SCE decided to create two short lists. The first—approximately 250 MW—would, based on appropriate contract finalization, be executed in accordance with the RSC Participant Instructions, regardless of the outcome of the RAM proceeding. A second provisional shortlist contained proposals SCE was willing to execute if the CPUC were to allow credit under a final decision adopting the Renewable Auction Mechanism program.

On October 4, 2010, SCE informed Offerors that their offers were shortlisted, provisionally shortlisted, or not shortlisted. Offers that were provisionally shortlisted were informed that SCE would consider finalizing a RSC with them if (a) one or more short-listed Offerors were unable to execute RSCs or (b) SCE elects to execute RSCs for more than 250 MW from this solicitation.

On November 19, 2010, SCE announced that pursuant to the RSC RFO it had signed 21 PPAs for renewable energy from nearly 259 of installed capacity from renewable energy projects of up to 20 MW. The contracts had been executed on November 15, 2010, as planned. The specific projects, the sellers, project location, technology, capacity, and estimated online date are summarized below.

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[16] *Id.* At 2.

CONTRACTS SIGNED BY SCE FOR 2010 RENEWABLE STANDARD CONTRACTS RFO				
Project Sponsor	Project	Location	Capacity (MW AC)	Est. Online Date
Amonix, Inc.	Blythe Solar Power Generation Station 1 LLC	Blythe	4.7	June-13
Amonix, Inc.	Garnet Solar Power Generation Station 1 LLC	North Palm Springs	4.8	June-13
Amonix, Inc.	Littlerock Solar Power Generation Station 1 LLC	Littlerock	5.0	Apr-13
Amonix, Inc.	Lucerne Solar Power Generation Station 1 LLC	Lucerne Valley	14.0	Mar-14
Clear Peak Energy, Inc.	Holiday Solar Array	Lancaster	8.5	Dec-13
Foresight Renewables, LLC	Nicolis, LLC	Weldon	20.0	Sep-13
Foresight Renewables, LLC	Tropico, LLC	Rosamond	14.0	Sep-13
juwi solar inc.	Sierra View Solar IV	Lancaster	19.0	Dec-13
juwi solar inc.	Sierra View Solar V	Mojave	19.0	Dec-13
Recurrent Energy	RE Columbia 2	Mojave	20.0	Jan-14
Recurrent Energy	RE Columbia 3	Mojave	10.0	Jan-14
Silverado Power	American Solar Greenworks	Lancaster	15.0	Apr-14
Silverado Power	Cemtral Antelope Dry Ranch B	Lancaster	5.0	Apr-14
Silverado Power	Cemtral Antelope Dry Ranch C	Lancaster	20.0	Apr-14
Silverado Power	Lancaster Dry Farm Ranch B	Lancaster	5.0	Apr-14
Silverado Power	Lancaster WAD B	Lancaster	5.0	Apr-14
Silverado Power	North Lancaster Ranch	Lancaster	20.0	Apr-14
Silverado Power	Sierra Solar Greenworks	Lancaster	20.0	Apr-14
Silverado Power	Victor Dry Farm Ranch A	Victorville	5.0	Apr-14
Silverado Power	Victor Dry Farm Ranch B	Victorville	5.0	Apr-14
Spinnaker Energy, LLC	Cabazon West Wind	Cabazon	19.5	Sep-12
# of Contracts	21			
# of Project Sponsors	7			
# of MWs	258.5			
Technology: All Projects are Solar PV except for Cabazon West Wind, which is a wind energy project.				

Subsequently, the power purchase agreement ("PPA") with Spinnaker Energy, LLC was terminated. As a result, SCE is seeking approval for 20 RSCs for projects with 239 MW of installed capacity.

On November 10, 2010, SCE had informed provisionally short-listed Offerors that if the Commission were to approve the RAM decision before the end of the year in a manner that would provide SCE with sufficient credit for executing additional contracts toward RAM goals, SCE would execute additional contracts. For Offerors willing to hold their offers open through the end of the year, SCE indicated that its intent would be to execute RSCs by the end of the year if it received a satisfactory CPUC decision. If not, the RSC would be concluded without the execution of any additional contracts.

On December 17, 2010, the Commission issued its Decision Adopting the Renewable Auction Mechanism.[17] With respect to SCE's RSC Program, the Commission addressed the issue of the relationship between RAM and the SCE's RSC Program and the credit that would be given for contracts entered into pursuant to the 2010 RSC Program.

> Our intent in establishing RAM is to create a standardized procurement process for projects up to 20 MW in size in order to promote robust competition and reduce the administrative burden associated with these projects. Going forward, RAM should be the primary procurement vehicle for projects in this size range, though projects may still participate in other Commission-authorized programs such as the annual RPS solicitations and Commission-approved utility solar photovoltaic programs. It is contrary to the intent of this program to allow projects in this size range to use other procurement options, in particular voluntary programs that target the same market segment or bilateral negotiations. Thus, going forward, SCE shall conform its Renewable Standard Contract (RSC) program to the guidance and framework provided herein. However, SCE may count contracts already executed pursuant to its 2010 RSC toward its capacity cap to the extent they are approved by the Commission. Furthermore, SCE may submit additional contracts resulting from its 2010 RSC solicitation via a Tier 3 advice letter for Commission approval, however, these additional contracts will not further reduce SCE's procurement obligation under the RAM program.[18]

On December 17, 2010, SCE notified provisionally short-listed bidders that it was concluding the 2010 RSC RFO without executing any additional RSCs.

E. Issues Addressed in This Report

This report addresses Merrimack Energy's assessment and conclusions regarding the following issues identified in the CPUC's IE Report Template:

1. Describe in detail the role of the IE through the solicitation and negotiation process.

2. How did the investor-owned utility ("IOU") conduct outreach to bidders, and was the solicitation robust?

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[17] Decision 10-12-048, R. 08-08-009 (December 17, 2010).
[18] D.10-12-048 at 3-4.

3. Describe the IOU's Least Cost Best Fit ("LCBF") methodology. Evaluate the strengths and weaknesses of the IOU's LCBF methodology.[19] (This should include a thorough analysis of the RFO results.)

4. Evaluate the fairness of the IOU's bidding and selection process (i.e. quantitative and qualitative methodology used to evaluate bids, consistency of evaluation methods with criteria specified in bid documents, etc.).

5. Describe project-specific negotiations. Highlight any areas of concern including unique terms and conditions.

6. If applicable, describe safeguards and methodologies employed by the IOU to compare affiliate bids or utility-owned generation ownership offers.

7. Based on the complete bid process, are the IOU's contracts the best overall offers received by the IOU?

8. If the contract does not directly reflect a product solicited and bid in the RFO, is the contract superior to the bids received on the products solicited in the RFO? Explain.

9. Is the contract a reasonable way of achieving the need identified in the RFO?

10. Based on your analysis of the RFO bids, the bid process, and the overall market, does the contract merit Commission approval? Explain.

These issues are addressed in this report.

II. Description of the Role of the IE

A. Regulatory Requirements for the IE

The requirements for participation by an IE in RPS solicitations are outlined in Decisions ("D").04-12-048 (Findings of Fact 94-95, Ordering Paragraph 28), D.06-05-039 (Finding of Fact 20, Conclusion of Law 3, Ordering Paragraph 8) of the CPUC, and D.09-06-050.

In D.04-12-048 (December 16, 2004), the CPUC required the use of an IE by investor-owned utilities (IOUs) in resource solicitations where there is an affiliated bidder or bidders, or where the utility proposed to build a project or where a bidder proposed to sell a project or build a project under a turnkey contract that would ultimately be owned by a

[19] The nature of this process was designed to rank offers based on the levelized price of the offers. The traditional IOU Least Cost Best Fit methodology was not applied in the evaluation and selection process. However, SCE, on an after-the fact basis, has applied its LCBF methodology to the RSCs for which approval is sought on a simplified basis and compared the results to the shortlisted projects in the 2009 RPS RFP shortlist. Our assessment focuses on the evaluation methodology used in the RSC ranking and selection process, but also addresses SCE's renewable premium/LCBF methodology.

utility. The CPUC generally endorsed the guidelines issued by the Federal Energy Regulatory Commission ("FERC") for independent evaluation where an affiliate of the purchaser is a bidder in a competitive solicitation, but stated that the role of the IE would not be to make binding decisions on behalf of the utilities or administer the entire process.[20] Instead, the IE would be consulted by the IOU, along with the Procurement Review Group ("PRG") on the design, administration, and evaluation aspects of the Request for Proposals ("RFP"). The Decision identifies the technical expertise and experience of the IE with regard to industry contracts, quantitative evaluation methodologies, power market derivatives, and other aspects of power project development. From a process standpoint, the IOU could contract directly with the IE, in consultation with its PRG, but the IE would coordinate with the Energy Division.

In D.06-05-039 (May 25, 2006), the CPUC required each IOU to employ an IE regarding all RFPs issued pursuant to the RPS, regardless of whether there are any utility-owned or affiliate-owned projects under consideration. In addition, the CPUC directed the IE for each RFP to provide separate reports (a preliminary report with the shortlist and final reports with IOU advice letters to approve contracts) on the entire bid, solicitation, evaluation and selection process, with the reports submitted to the utility, PRG, and CPUC and made available to the public (subject to confidential treatment of protected information). The IE would also make periodic presentations regarding its findings to the utility and the utility's PRG consistent with preserving the independence of the IE by ensuring free and unfettered communication between the IE and the CPUC's Energy Division, and an open, fair, and transparent process that the PRG could confirm.

In D.09-06-050 issued on June 18, 2009 in Rulemaking 08-08-009, Order Instituting Rulemaking to Continue Implementation and Administration of California Renewables Portfolio Standard Program,[21] the CPUC required that bilateral contracts should be reviewed according to the same processes and standards as contracts that come through a solicitation. This includes review by the utility's PRG and its IE, including a report filed by the IE.

B. Detailed Description of the Role of the IE

SCE selected Merrimack Energy to serve as IE for the 2010 Renewable Standard Contracts Program. The objective of the role of the IE is to ensure that the solicitation process is undertaken in a fair, consistent, unbiased, and objective manner and that the best resources are selected and acquired consistent with the solicitation requirements.

In addition to the requirements identified in CPUC Orders, the Purchase Order between Merrimack Energy and SCE identifies the tasks to be performed by the IE. These include the following tasks:

[20] Decision 04-12-048 at 129-37. The FERC guidelines are set forth in Ameren Energy Generating Company, 108 FERC ¶ 61,081 (June 29, 2004).
[21] Decision Establishing Price Benchmarks and Contract Review Processes for Short-Term and Bilateral Procurement Contracts for Compliance with the California Renewable Portfolio Standard.

- Consult with SCE on the design, administration, and evaluation of the competitive procurement solicitation process and protocols to ensure that no SCE affiliate has an undue advantage over non-affiliates in the solicitation;

- Ensure the solicitation process is open, transparent, and free from anti-competitive behavior;

- Provide recommendations concerning the precise definition of products sought and price and non-price evaluation criteria, so that all aspects of the products are clearly understood and all Sellers may effectively respond to the solicitation;

- Review the comprehensive quantitative and qualitative bid evaluation criteria and methodologies and assess whether these are applied to all bids in a fair and non-discriminatory manner;

- Assess whether SCE's final selection was fair and was not unduly influenced by its affiliate relationships;

- Provide periodic presentations as requested to SCE management and to the PRG concerning the IE's findings;

- Report on the outcome of the RFP to the CPUC using the appropriate CPUC Independent Evaluator Report Template.

With regard to the role of the IE, our objective is to ensure that the process is undertaken in a fair and equitable manner and that the results of the offer evaluation and selection are accurate, reasonable and consistent. This role generally involves a detailed review and assessment of the evaluation process and the results of the quantitative and, to the extent applicable to the particular solicitation, qualitative (non-price) analysis.

This report provides an assessment of SCE's RSC procurement process from development of the process through selection of the projects subject to contract approval. It is organized based on the template provided by the CPUC's Energy Division.

C. Description of IE Oversight Activities

In performing its oversight role, the IE participated in and undertook a number of activities in connection with the RFO, including submitting comments and clarification questions on the draft RFO protocol, attending the web conferences regarding the RFO and the pro forma renewable standard contracts, organizing and summarizing the offers submitted, reviewing evaluation results at each stage in the process, monitoring the status of short-listed and provisionally short-listed offers, monitoring communications with Offerors, attending conference calls with short-listed and provisionally short-listed Offerors regarding project-specific changes to the RSCs, participating in SCE project team meetings, and attending meetings with the SCE's Risk Management Committee ("RMC") and PRG. Merrimack Energy was retained by SCE one week prior to the launch of the RFO and therefore had a limited opportunity to review and comment on the RFO and the RSC pro forma contracts before they were posted on SCE's website on August 2, 2010.[22] A list of the activities of the IE during the procurement process is described below.

1. Participated in Renewable and Alternative Power ("RAP") Committee Meetings

After Merrimack Energy was retained by SCE one week prior to the launch of the RFO, Merrimack Energy was invited by SCE's management team to participate in meetings of the RSC program team and other meetings during the RSC solicitation implementation phase, including bi-weekly RAP meetings. This allowed the IE to monitor the major activities and issues that were being debated and assessed by SCE's RSC project team during this phase of the process.

2. Submitted Comments and Clarifying Questions on the Draft RSC RFO

The IE submitted a few comments on the draft RSC RFO in late July and also submitted several clarifying questions designed to make the document clearer to prospective Offerors.

3. Monitored Web Conference Held on August 10, 2010

Merrimack Energy submitted comments on the draft presentation for the 2010 RSC RFO Conference and monitored the conference, which was conducted as a web conference on August 10, 2010. SCE provided an overview of the RFO, the RFO instructions, the offer template and revenue calculator, the evaluation criteria, the RFO schedule, and key terms and conditions in the RSCs. In addition, SCE provided an overview of the interconnection process, both at the distribution level and at the transmission level. Following SCE's presentation, there was a question and answer period. SCE's presentation, a document summarizing the questions and answers, and an audio recording of the web conference were all posted on SCE's website.[23]

4 Monitored SCE Internal Communications Involving Revisions to RFO Participant Instructions

The IE monitored internal SCE communications pertaining to revisions to the RFO instructions regarding Offeror redlining of the RSC pro forma and the Offeror's availability for specific times to address project-specific contract language if the Offereor was shortlisted and desired to have a meeting or conference call to discuss these matters. A revision to the RFO Participant Instructions was posted on SCE's website on August 16, 2010. On September 8, 2010, the RSC Offer Template was revised to require that four contract prices be submitted in the context of defined curtailment cap provisions.

5. *Review of Comments on the Draft Pro Forma RSCs*

[22] A draft of the RSC RFO Participant Instructions was provided to Merrimack Energy on July 29, 2010.
[23] http://www.sce.com/EnergyProcurement/renewables/rsc-web-conference.htm.

SCE provided prospective bidders with the opportunity to submit comments on the draft pro forma RSCs in the form of a redline. Comments were due by August 18, 2010. Over a dozen prospective bidders submitted comments. The IE reviewed the bulk of the comments submitted. In addition, the IE compared the 2010 RSC pro forma contracts to the 2009 RSC contracts. Merrimack Energy followed up with a conference call with SCE's RSC project manager and lead counsel regarding suggested changes to the pro forma contracts. On September 1, 2010, SCE posted final RSC20 and RSC5 pro forma contracts.

6. Monitored Web Conference Held on September 3, 2010—Review of Pro Forma RSC

On September 3, 2010, SCE held a web conference in which the company provided an overview of the final pro forma RSCs, addressed the curtailment provisions in some detail as well as the seller's obligation to seek full deliverability status in the interconnection process, and summarized certain contract provisions that had been modified. In addition, a question and answer session was held. The presentation, a recording of the web conference, and a Q&A document was posted on SCE's website. The IE monitored the web conference.

7. Monitored Communication with Bidders

Prospective Offerors had the opportunity to submit questions to SCE regarding the RFO via SCE's RSC RFO website and through direct contact with SCE project team members. The RFO required that the IE should be copied on all correspondence between SCE and the prospective Offeror. The IE reviewed the email traffic between SCE and Offerors to assess if any issues were emerging and whether all Offerors were treated fairly and equitably.

8. Receipt of Offers and Required Information

The Offers were received on September 15, 2010 as required. Offers were sent to both SCE and the IE via email. SCE reviewed and compiled the information submitted and began to organize and summarize the offers received.

9. Evaluation and Short List Selection; Attendance at RMC and PRG Meetings

Offers were reviewed and evaluated in terms of their levelized $/MWh price based on the best offer of the four submitted with regard to the curtailment options allowed. A few offers were determined to be either ineligible or not viable for the following reasons:

- One project was not located in the CAISO control area;

- A number of projects were located in transmission constraints areas which would not allow the project to achieve commercial operation within the timeframe set forth in the RSC RFO.[24]

The IE reviewed SCE's ranking based on price and SCE's basis for determining that certain projects were not eligible or could not meet the minimum online date requirement set forth in the RFO. Another matter that the IE reviewed was SCE's plan to apply supplier concentration risk parameters to the ranking of bids.

The IE attended by telephone RMC and PRG meetings both of which were held on September 29, 2010. RAP provided an overview of the number of offers received, the quantity in terms of MWs and GWhs, price and estimated notional value. RAP recommended a short list comprised of 259 MW of RSC projects, regardless of the outcome of the RAM decision by the Commission.[25] In light of the attractive pricing received, RAP recommended the provisional shortlisting of additional MW if the Commission were to allow credit toward meeting the RAM requirements.

<u>10. Participate in Contract Negotiations</u>

The IE monitored the bulk of the project-specific contract negotiations that took place in October 2010. Due to the number of negotiations and the short period of time allotted for them, SCE established two teams of negotiators, which were monitored by two Merrimack Energy representatives. Initially, SCE scheduled meetings of the two internal teams to assure that they were acting consistently, but only one meeting was held after it was concluded that there were relatively few material issues to address.

<u>11. Final RMC and PRG Meetings—November 9-10, 2010</u>

By early November, there were a number of changes to the short list, although the amount of shortlisted MW remained at 259 MW. Some previously short-listed projects were removed as a result of withdrawn offers or transmission constraints. Also, project substitution was proposed by the same Offerors for projects that were either subject to transmission and interconnection constraints or were more viable projects. Other projects on the provisional short list were moved up to take the place of projects originally on the short list that were withdrawn. Merrimack Energy attended a RMC meeting on November 9, 2010 at which approval was given for the execution of 21 RSC contracts, as well as a PRG meeting held the following day at which the RSC contract awards were discussed. The provisional shortlist, which itself had shrunk in size due to similar issues facing projects on the initial shortlist, was put on hold pending the Commission's decision on the RAM.

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[24] Another project was considered non-viable for multiple reasons, including a schedule that was deemed infeasible.
[25] The reason for 259 MW was that the project that was included to reach 250 MW was sized so that its inclusion resulted in the total of shortlisted projects equaling 259 MW.

The 21 RSC contracts were executed by SCE on November 15, 2010, the scheduled date for contract execution. Following the Commission's RAM decision on December 16, 2010, SCE informed Offerors on the provisional shortlist that SCE was concluding the RSC RFO without executing additional contracts.

III. Adequacy of Outreach to Prospective Bidders and Robustness of the Solicitation

SCE's outreach activities for the 2010 Renewable Standard Contract program were substantial and although there wasn't as much advance notice provided to the prospective bidder community as in many competitive procurements, the result was a very competitive solicitation. The other factor that contributed to the robustness of the solicitation was the simplicity of the process and perhaps the relative dearth of threshold requirements, such as the filing of an interconnection request and demonstration of site control.

On April 9, 2010, SCE included in its first amendment to its 2010 RPS procurement plan a statement that it was planning a RSC procurement for 2010 with a goal of purchasing 250 MW from eligible renewable energy projects under long-term contracts.[26] SCE also provided notice that it would be doing so under a RFO process rather than offering to purchase at the MPR.[27]

On July 22, 2010, SCE issued to its email distribution list a notice that it would officially launch the 2010 RSC RFO on August 2, 2010 through a posting on its website. SCE also announced that it would be holding a web conference for the RSC RFO on August 10, 2010.

Over the years, SCE has developed a large list of potential bidders based on contacts from previous renewable solicitations and business relationships it has developed. This list is periodically updated. SCE used this list with over 1,100 contacts as the database for prospective bidder contact and outreach. SCE sent emails to all contacts on this list informing them of the launching of the RSC RFO process, the web conferences, and the setting up and updating of the 2010 RSC RFO website.

SCE established a website for the program—on August 2, 2010, which was subsequently supplemented and revised—and included all relevant documents on the website. The website contains the following documents:

[26] Southern California Edison Company's (U-338-E) Amended 2010 RPS Procurement Plan (April 9, 2010) at 29-30.
[27] *Id.* The plan to conduct the 2010 was also discussed in SCE's Second Amended 2010 RPS Procurement Plan filed on June 17, 2010 (pp. 28-30).

- RFO participant instructions;
- Renewables standard contracts—5 MW and 20 MW versions;
- Offer template and revenue calculator;
- TOD and payment allocation table;
- Audio recordings, PowerPoint presentations and written questions and answers from the two web conferences held on August 10, 2010 and September 3, 2010;
- Link to website on WDAT tariff and WDAT generator interconnection reform process;
- Form non-disclosure agreement;
- Contact information for SCE and the IE.

The website has been in place for several years going back to the initiation of the RSC program in 2007. It was updated in 2010 in connection with the changes in the renewable standard contract program for 2010.[28]

Once the process was initiated, SCE provided useful information to prospective bidders through two web conferences. The first web conference addressed the basic design of the RFO process, the schedule, what Offerors would be required to submit, some important terms of the renewable standard contracts, including security requirements and curtailment provisions, the process by which SCE would be obtaining feedback on the standard contracts and posting final pro forma standard contracts, and a summary of SCE's Wholesale Distribution Access Tariff ("WDAT") interconnection process and cost allocation provisions as well as those of CAISO's Small Generator Interconnection Process ("SGIP") and the applicability of the respective generator interconnection processes for generators.

At the second web conference held on September 3, 2010, SCE summarized the schedule for the next steps in the process:

- Submission of offers, including redlining the appropriate standard contracts with "project-specific" changes (September 15, 2010);
- SCE notification of Offerors regarding short list status (September 30, 2010);
- SCE submits draft RSCs and NDAs to short-listed Offerors (October 5, 2010);
- Meeting/conference calls with short-listed Offerors, if desired by the Offeror (October 6-15, 2010);
- Offerors submit executed RSCs (November 5, 2010);
- SCE executes final RSCs (November 15, 2010).

The key substantive part of the second web conference was a summary of certain major provisions of the pro forma standard contracts which had been revised from the draft pro forma standard contracts initially posted on SCE's web site. The draft pro forma

[28] In addition, SCE personnel had provided general notice of the 2010 RSC solicitation to potential bidders through other, less formal means, such as responses to email and telephone requests following the conclusion of the 2009 RSC program and through attendance at various workshops and conferences.

contracts had been the subject of comments from prospective Offerors. A substantial part of the presentation focused on the curtailment provisions, which are complex and which had undergone several changes. One change was to give Offerors the option of submitting Offers where on-peak hours would not be included in the curtailment cap.

Another change pertained to steps required of Offerors to obtain full deliverability status as part of the CAISO interconnection process if that option becomes available under CAISO rules for small generators (up to 20 MW) and to pay for deliverability network upgrades, subject to a cost cap of $100,000 per MW of Contract Capacity. The revised pro forma RSC only required Sellers to take such steps as would not reasonably jeopardize Seller's achievement of the Commercial Operation Date and put other limits on Seller's obligations.

Other changes, in response to bidder feedback, included:

- Limited extension of the Commercial Operation Date due to Force Majeure and other specified causes;
- An indication that it would consider changes to the section on termination rights (Section 2.04);
- The performance obligation for solar PV projects was revised to 170% of expected energy production over two years (85% annually averaged over two years) rather than 90% per year

On September 8, 2010, one week before Offers were to be submitted, SCE updated its offer template to require four offers, instead of two price offers:

- On-peak hours included in curtailment cap: 50 hour curtailment cap multiplier
- On-peak hours included in curtailment cap: 100 hour curtailment cap multiplier
- On-peak hours not included in curtailment cap: 50 hour curtailment cap multiplier
- On-peak hours not included in curtailment cap: 100 hour curtailment cap multiplier

This change was highlighted on the web site and in an email sent to prospective Offerors on SCE's distribution list. Through that same email, SCE notified prospective Offerors of the CPUC's proposed RAM decision and stated:

> At this time, SCE will accept offers on September 15 according to schedule. If, however, the RAM proposed decision is not satisfactorily resolved by November 15, then SCE will not execute contracts from this solicitation. In the meantime we will continue with all other RSC solicitation efforts as outlined in the posted RFO Participant Instructions. We will keep RSC participants informed of any changes or updates to the RSC solicitation as the RAM regulatory proceeding evolves. Please feel free to contact the SCE RSC team if you have questions.

The response to the program has been extremely robust. Specific information regarding the number of offers received and the associated amount of installed capacity is in Confidential Appendix A to this report.

Given the highly robust response to the solicitation, we are of the opinion that SCE's outreach to bidders was adequate, if not very good to superior. The website contained the necessary documents and other information, which were clearly stated. The web conferences were, in our opinion, a very useful tool in providing information to prospective bidders and in providing answers to questions. SCE allowed prospective bidders to comment on the draft pro forma contracts, and in light of the comments received made various changes in finalizing the pro forma contracts. Written responses to questions were posted on the website. The very strong response of the market to SCE's RSC RFO is evidence that the outreach activities of SCE were effective and Sellers felt they had an adequate opportunity to receive a contract from the process. However, we do have reservations with the manner in which SCE communicated to prospective bidders regarding the Company's willingness to go forward with the RSC process to contract execution and the relationship to the pending Commission decision on RAM, which is addressed in Section V.B of this report.

SCE issued surveys to participants at the RFO web conferences requesting that they respond with their views regarding the conferences. Overall, the responses were very favorable. There were a number of suggestions for future improvements, including providing more notice prior to the date of the web conference, posting the questions on the web prior to the answers being given, and providing examples for some of the matters addressed.

IV. Fairness and Appropriateness of the Bid Evaluation and Selection Design

A. Framework and Principles for Evaluating SCE's 2010 RSC Methodology

This section of the report addresses the principles and framework underlying Merrimack Energy's review of SCE's methodology for the RSC RFO proposal evaluation and selection. Key areas of inquiry by the IE and the underlying principles used by the IE to evaluate the methodology include the following:

- Were the procurement targets, products solicited, principles and objectives clearly defined in SCE's RFO and other materials?

- Were the bid evaluation and selection process and criteria reasonably transparent such that bidders would have a reasonable indication as to how they would be evaluated and selected?

- Was SCE's bid evaluation based on and consistent with the information requested in the RFO to be submitted by bidders in their proposal documents?

- Did the evaluation methodology reasonably identify the quantitative and qualitative criteria and describe how they would be used to qualify and rank offers?

- Does the price evaluation methodology allow for consistent evaluation of bids of different sizes and in-service dates?

- Did the bid evaluation criteria and evaluation process contain any undue or unreasonable bias that might influence project ranking and selection results or in any way favor affiliate bids?

- Was the RFO clear and concise to ensure that the information required by SCE to conduct its evaluation was provided by project sponsors?

B. Description of SCE's Evaluation Methodology

1. The 2010 RSC Evaluation Methodology

This section of the report provides an overall description of SCE's evaluation methodology and criteria applicable to the 2010 RSC RFO. SCE used a levelized cost methodology to evaluate and rank all offers. SCE described the offer evaluation and selection process in the RFO Participant Instructions and at the first web conference. SCE devised the evaluation methodology and selection process in the context of its stated goal—"to provide a standardized procurement process for projects not greater than 20 MW that leads to quick execution (relative to other procurement processes)."[29]

The RSC RFO provided for a single stage bidding process where bids would be evaluated from a price perspective solely on the basis of levelized costs. The more complex evaluation methodology used in connection with the 2009 RPS RFP (and proposed to be used in connection with the 2010 RPS RFP) would not be utilized. The RPS RFP least-cost best-fit methodology is based on a $/MWh renewable premium approach—which compares the levelized $/MWh costs of a proposal, including the bid energy costs, costs associated with transmission network upgrades (transmission adders) and debt equivalence, to the levelized estimated market value of the energy and capacity (resource adequacy) benefits associated with a proposal.

The RSC RFO also differed in several important respects from the Solar Photovoltaic Program RFO ("SPVP RFO") conducted by SCE earlier in 2010. In this program,

[29] RFO Participant Instructions at 1. As previously noted, the traditional least cost best fit methodology used by SCE for other renewable solicitations was not applicable to the RSC RFO process, which was designed largely to facilitate the development of smaller renewable energy projects with installed capacities of 20 MW or less.

primarily oriented to solar rooftop proposals of approximately 2 MW or less, the RFO had an indicative bidding stage and a final binding bid stage. In addition, applicants were required to have submitted an interconnection request and to have demonstrated, or at least to have certified that they had, site control. In the SPVP RFO, Offeror were required to provide a schedule such that the expected commercial operation date would occur within 18 months of CPUC approval, while in the RSC RFO, the scheduled expected commercial operation date would occur within 36 months of CPUC approval. Like the SPVP RFO, however, the price evaluation was based solely on levelized cost in $/MWh.

As stated in the RSC RFO Participant Instructions, participants could either submit a proposal for (a) a standard contract for projects not greater than 5 MW ("RSC5") or (b) a standard contract for not less than 20 MW ("RSC20"). The standard contracts are identical except with respect to project development security and performance assurance (operating period security). For RSC5, development security is $30/kW for intermittent projects (wind and solar PV) and $60/kW for baseload projects (biomass). There is no performance assurance. For RSC20, development security is $60/W for intermittent projects and $90/kW for baseload projects; performance assurance is an average of 5% of total project payments. Offerors also had the ability to make proposals for 10, 15 or 20 year contracts.

From an evaluation standpoint, proposals for RSC5 and RSC20 contracts, regardless of contract term, were to be treated in the same fashion. All projects were to be ranked on a $/MWh price basis, regardless of size, term, or projected commercial operation date.

However, to be ranked, each offer would need to meet certain specified eligibility and threshold requirements:

- Offers must be for the output from an eligible renewable resource ("ERR"), a generating facility that satisfies the criteria set forth in the California Renewable Portfolio Standard and the California Energy Commission's RPS eligibility guidebook; existing generating facilities must be certified by the California Energy Commission as an ERR;

- The ERR must be located within the CAISO control system;

- The ERR must be scheduled to commence operation within three years from CPUC approval of the RSC.[30]

With regard to evaluation and short-listing of offers, SCE stated that it would rank offers based on levelized price (lowest offers ranked highest) up to a maximum capacity of 250 MW. However, SCE reserved the right to use other criteria to make selection determinations. As stated in the Participant Instructions, "SCE reserves the right to evaluate and select offers on other quantitative and qualitative metrics depending on

[30] RFO Participant Instructions at 2.

market response."[31] In response to questions at the first web conference on offer evaluation and selection, SCE stated:

- "We reserve the right to select or deselect projects based on uniquely good or bad attributes (qualitative factors), such as project viability or supplier concentration risk."
- "Commercial operation date may be considered as a qualitative factor when evaluating offers."
- In response to a question as to whether there is a limit on the number of projects a single sponsor may propose, SCE stated: "No. However, supplier concentration risk may be a qualitative factor used when evaluating offers."[32]

There were also a number of process-oriented requirements for Offerors. These included the timely submission of the Offer Template and a redline to the applicable renewable standard contract (RSC5 or RSC20). SCE stated that it was "willing to consider changes to the draft RSC that are **unique** to the Project."[33] As indicated previously, Offerors were requested to make four separate price offers per project, based on specified provisions applicable to curtailment.

2. Renewable Premium Analysis and 2009 RPS RFP Least Cost Best Fit ("LCBF") Methodology

Following the receipt of bids in the RSC RFO, SCE conducted a modified renewable premium analysis so that the selected projects could be compared to the shortlist from SCE's 2009 RPS RFP. SCE used the same renewable premium evaluation methodology and forecast as had been used in the 2009 RPS RFP, except that a generalized estimate was used for the locational capacity value and transmission adder for all of the projects, rather than a project-specific estimate. A comparison of the renewable premiums for the RSCs for which approval is being sought to the renewable premiums of the projects shortlisted in the 2009 RPS RFP is set forth in Confidential Appendix A to this report. SCE's LCBF methodology used in the 2009 RPS RFP is described in Appendix B to this report.

C. Evaluation of the Strengths and Weaknesses of SCE's Methodology in This Solicitation

Strengths of Evaluation and Ranking Methodology

As described, if an offer meets the eligibility requirements, the key selection criterion is price. SCE's price ranking and evaluation methodology is designed to be relatively simple and straightforward. Offers are ranked based on the levelized price of the offer

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[31] RFO Participant Instructions at 5.
[32] Q&A from RSC RFO Web Conference #s 46, 47 and 59, http://asset.sce.com/Documents/Shared/100818_RSC_RFO_WebConferenceQandA.pdf.
[33] RFO Participant Instructions at 5 (emphasis in original).

using a 10 percent discount rate. Offerors are provided the flexibility with respect to length of term (10, 15 of 20 years) and to offer a fixed price over the contract term or a price which escalates by a fixed escalation factor. The conceptual approach was simple and the Offer Template provided by SCE for bidders to use was relatively easy for Offerors to follow and complete. Offerors appeared to have little or no difficulty with this process.

The 2010 RSC program allowed developers of small projects the opportunity to obtain relatively expeditiously and with low transaction costs long-term PPAs to support further development and financing of construction of their projects. Strengths of the program are its simplicity, short time between RFO launch and contract execution—a little more than three months—and the competitiveness of the process resulting in attractive market-driven pricing. Another strength was the role of project development security, whose levels depended on project size (up to 5 MW vs. up to 20 MW) as a partial substitute for project viability analysis. Several developers who applied for a RSC either withdrew their applications, did not execute contracts or did not post development period security either because of a known project development problem or presumably because of some other issue affecting project viability not communicated to SCE or the IE. Project development security has the effect of facilitating the weeding out of projects with serious project development problems by the bidders themselves.

Other strengths were the ability to apply other qualitative factors in the evaluation of Offers—specifically, supplier concentration risk and the ability of a project sponsor to achieve commercial operation of the project within three years of CPUC approval. The latter factor allowed SCE to address project viability concerns to an extent in the context of a large bidder response and an aggressive timeframe for bid evaluation, negotiation and contract execution.

The target of up to 250 MW in renewable standard contracts was a reasonable one and was in line with the program goals in 2009. The RSC program design treated all ERRs in a technology neutral manner and treated all applicants in a similar manner, regardless of whether or not they were affiliated with SCE.

Finally, it was also useful both to SCE and developers that a significant amount of incremental renewable energy projects could be contracted with a relatively small amount of time and effort expended on contract negotiations.

Weaknesses of the Evaluation and Ranking Methodology

The 2010 RSC program also had a number of weaknesses, many of which are related to its strengths. First, the price evaluation mechanism does not take into consideration indirect costs, in particular the costs associated with transmission upgrades. Hence, the simplicity of the pricing approach comes at the cost of accuracy in terms of assessment of customer costs and benefits. However, in light of the size of the projects, this tradeoff seems reasonable in the context of the benefits of expedition and lower transaction costs.

Another weakness is the relatively low level of requirements and evaluation factors pertaining to project viability. There was no requirement that an Offeror had to demonstrate site control (or certify that it had site control) or that it was pursuing the interconnection process. The only applicable requirement—not in the 2009 RSC RFO—was that the scheduled commercial operation date had to be within three years of CPUC approval (or about four years after bid submittal).

Another area that this type of solicitation process could be improved pertains to the clarity by which the evaluation/selection criteria could be articulated. While SCE reserved the right to consider such factors as supplier concentration risk and whether the scheduled commercial operation date is within three years of commercial operation, it was not very clear how SCE would apply these criteria. A number of improvements in the process (which might be applicable in future RAM solicitations) are suggested below.

<u>Strengths and Weaknesses of SCE's LCBF Evaluation Methodology</u>

SCE's LCBF methodology allows for an evaluation of different types of renewable resources and different terms in a consistent manner by accounting for both the costs and benefits of each proposal. The LCBF methodology also accounts for qualitative factors including viability and project development status, which are important factors in the ultimate success rate for these projects.

The primary metric used in the LCBF evaluation was the renewable premium metric – the difference (in $/MWh) between the levelized nominal costs associated with a proposal and the levelized nominal benefits. In our experience, the renewable premium metric is a commonly accepted and appropriate measure of comparative value.

While the LCBF methodology is designed to allow for an assessment of all reasonable costs, and compare it to the value of the products bid, there were several weaknesses in applying the the quantitative evaluation in the context of the 2009 RPS RFP that in our view should be explored by SCE for improvements in future solicitations.

In applying the 70% exceedance methodology for assessing capacity value of intermittent resources, there were issues with the evaluation of certain proposals because the production profile provided by certain bidders represented average hourly generation rather than an estimate of generation for each hour in the year. While these issues were satisfactorily addressed in the 2009 RPS RFP in our view, in the future SCE should ask for hourly generation estimates or explain the methodology used by SCE to ensure that all bids can be consistently evaluated relative to their capacity value.

The quantitative evaluation of out-of-state projects, especially wind projects, proved to be difficult for SCE and the IE in the 2009 Renewable RFP process. A significant variety of out-of-state proposals were submitted that were difficult to compare to each other and to in-state projects on a consistent basis. Initially, while the Renewable RFP Procurement Protocol and other RFP documentation appeared clear regarding requirements pertaining to delivery points and pricing, there were many proposals that were not in conformance with those requirements and this made it difficult to evaluate and compare all proposals on a consistent basis.

D. Recommended Future Improvements in the Evaluation and Ranking Process

In future solicitations of this nature, the standards for supplier concentration could be set forth in the RFO protocol document itself. Specifically, a maximum MW or MWh amount or percentage limitation or permissible range could be specified. A number of competitive solicitations of which we are aware have supplier concentration limits as part of the RFO program design. Our recommendation is that SCE do so in the context of future solicitations similar to the RSC RFO. It will help simplify and expedite the evaluation and selection process and will provide fair notice to prospective bidders regarding the rules to be applied regarding supplier concentration limits.

In the future, SCE should also provide a clearer notice to prospective bidders that it would be evaluating the reasonableness of the Offeror’s ability to achieve commercial operation within a certain timeframe. In addition, bidders should be required to provide a project milestone schedule, which would assist SCE in making its evaluation.

While for purposes of this RSC it was arguably reasonable to not impose overly restrictive requirements for Offerors in terms of meeting project development requirements at the time of bid submission, it is reasonable in the future to require that short-listed bidders provide a demonstration of site control and that they have commenced the interconnection process by submitting an interconnection request, at least prior to the execution of a PPA. This approach would provide a reasonable tradeoff, in our opinion, between requiring that certain project development milestones be satisfied at the time bids are submitted versus not requiring that they be satisfied at all (except as a contract compliance matter). This approach would provide a degree of assurance regarding project viability, while mitigating the costs and risks for developers of small projects in submitting bids and perhaps reducing the burden on the generator interconnection process at the CAISO and utility levels.

Another area for improvement is the manner in which the standard contracts were developed. SCE started with its most recent RPS pro forma PPA, which is approximately 200 pages in length. While it had used a more simplified standard contract in the 2009 RSC process, SCE did not include some of the more simplified or at least acceptable contract provisions from a project developer standpoint in the initial draft pro formas (apparently, last year’s RSC pro formas were not even reviewed in preparing the initial pro forma contracts posted on the RSC RFO website). This led to more effort on the part of SCE and the prospective bidders than was perhaps necessary. However, SCE was developing these standard contracts only weeks after it had worked to incorporate revised curtailment provisions and provisions pertaining to sellers seeking full capacity interconnections in its pro forma RPS contract. Hence, the task was difficult and the time was short. Moreover, SCE did solicit comments on the pro forma contracts and did make some changes after having taken the comments into consideration.

V. Fairness of SCE's Administration of the Evaluation and Selection Process

A. Principles and Guidelines Used to Determine Fairness of Process

In evaluating SCE's performance in implementing the 2010 RSC RFO process, Merrimack Energy has applied a number of principles and factors, which incorporate those suggested by the Commission's Energy Division as well as additional principles that Merrimack Energy has used in its oversight of other competitive bidding processes. These include:

- Were all Offerors treated the same regardless of the identity of the Offeror?
- Were Offerors' questions answered fairly and consistently and the answers made available to all?
- Was the economic evaluation of the bids fair and consistent?
- Were the requirements listed in the Procurement Protocol applied in the same manner to all proposals?
- Was there evidence of any undue bias regarding the evaluation and selection of different types of product, project structures, or bid sizes that cannot be reasonably explained?
- Did all bidders have access to the same information?

B. SCE's Administration of the RSC RFO Process

As previously discussed, the IE was actively involved in all phases of the process. The IE was copied on all emails exchanged between SCE and Offerors including receiving copies of all offers, supporting documents, and contracts. The IE was also included in project team meetings to discuss the status of the process and issues which were raised.

SCE received proposals from several dozen project sponsors, with a number of project sponsors making offers for multiple projects. Projects were evaluated and ranked based on their levelized cost. In addition, several initial screens were run to evaluate the bids.

- SCE's transmission and distribution business unit was asked to assess whether any projects could not be interconnected in a four-year period; based on this analysis, SCE initially determined that several projects would not be able to achieve commercial operation within three years of CPUC approval;

- Another proposed project was not located within the CAISO control area and, hence, was determined not to be eligible.

In addition, a price screen was applied which eliminated more than 50 percent of the highest-priced offers. One project sponsor proposed several dozen projects involving hundreds of megawatts of installed capacity. In order to manage supplier concentration risk, SCE decided to limit the projects on the short list to a total of approximately 100 MW, which represents 40 percent of the 250 MW target for the solicitation. A provisional short list of several hundred MW of additional projects was established. The purpose of the provisional short list was twofold:

1. As a back up to the short list if projects were to fall out of the short list (for example, if there was a failure to execute the applicable RSC); and

2. As an additional short list if the CPUC were to allow SCE to "count" contracts for more than 250 MW toward meeting SCE's obligations under a final RAM decision.

A total of 21 projects totaling 259 MW were initially shortlisted by SCE. There were several hundred megawatts of projects placed in the provisional shortlist. Following project-specific contract discussions and further review by SCE, there were a number of changes to the shortlist and provisional shortlist but a total of 21 projects totaling 259 MW remained on the short list and ultimately were the subject of executed contracts. Based on further review by SCE, more projects were considered to be transmission constrained and unlikely to be able to achieve commercial operation within three years of CPUC approval.[34] Offers for contracts from existing projects with remaining contract terms were revalued to take into consideration the ratepayer costs associated with replacing power sold under an existing contract with a higher-priced new contract. Once this revaluation was conducted, the existing projects fell out of the short list. Finally, several Offerors withdrew their offers.

As part of this process, a few Offerors, some with multiple projects on the short list, proposed to substitute projects with those on the provisional shortlist that were considered by the Offeror and/or SCE as being more viable. After discussion with the IE, SCE permitted project swaps for viability reasons as long as it did not result in an increase in the weighted average price of projects that would receive contracts.

The net result was that the number of projects and the total MWs in the short list remained the same although some projects had fallen out of the original short list and

[34] Where SCE viewed the ability to go through the interconnection process in a timely matter as being uncertain, the Offeror was given the benefit of the doubt.

some projects had moved up from the provisional short list. In addition, the amount of projects and MWs on the provisional shortlist had dropped substantially.[35]

Based on our involvement, our assessment is that SCE reasonably followed the criteria set forth in the RFO Participant Instruction in the evaluation and selection process portion of the solicitation. As stated previously, our recommendation is that in future solicitations that (a) the seller concentration limits be explicitly addressed in the RFO program design documents so that all bidders are informed of them before bids are submitted and (b) the analysis that would be conducted regarding ability to achieve commercial operation by a specified date be explained before the submission of bids. With that being said , we believe that the evaluation that was conducted was consistent and equitable among different Offerors and proposed projects. No evidence of bias was present.

Based on our assessment of the evaluation process relative to the above criteria, it is our opinion that all Offerors were treated fairly and consistently and all generally had access to the same amount and quality of information.

As indicated previously, SCE maintained a website dedicated to the 2010 RSC RFO and posted the RFO documents on the website as well as presentations from the two web conferences, questions and answers and audio recordings of the web conferences. We observed no difference in the treatment of Offerors regarding clarification questions, correspondence and communications with Offerors, and follow-up contacts.

We did have concerns, however, with the way that SCE communicated the relationship between its willingness to go forward with the RSC program to contract execution and the pending Commission decision on RAM. SCE's statement to prospective bidders one week before offers were due that "SCE will not execute contracts from this solicitation" "if . . . the RAM proposed decision is not satisfactorily resolved by November 15" raised a number of questions from the IE's perspective. Would making such a statement shortly before offers were due discourage prospective bidders from participating in the solicitation and produce a suboptimal level of competition? On the other hand, since the RSC was a voluntary program and SCE was considering not going forward with it unless it would receive "credit" from the CPUC toward its obligations under a RAM decision, would it have been inappropriate for SCE *not* to provide notice to prospective bidders regarding the potential for conclusion of the RSC RFO without signed contracts? Assuming that it was appropriate to provide notice to prospective bidders, did SCE do it in a reasonable fashion by stating that it "will not" execute contracts if it did not receive a satisfactory RAM decision?

Importantly, the market's response to the solicitation was very strong—the solicitation was highly competitive. There is no indication that any prospective bidder in fact decided not to submit an offer due to SCE's statements prior to the due date for offers. Further, we concur with SCE's decision to inform prospective bidders regarding the potential for not executing contracts as a result of the solicitation due to the interaction

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[35] As indicated previously, one project for which a PPA was executed is not the subject of SCE's advice letter because the PPA was subsequently terminated.

with a decision in the RAM proceeding. It was appropriate to provide this information to prospective bidders, who could make their own judgments about whether or not to participate in the RSC RFO. Nor do we take issue with whether the statement at the time it was made reflected SCE's thinking at the time. Finally, we do not take issue with whether SCE had the legal right not to proceed with the 2010 RSC program.

We do, however, think that it was unnecessary for SCE to state that it *will not* execute any RSC contracts unless it was satisfied with an ultimate RAM decision. To our knowledge, a firm decision at that time had not been made by SCE's management, and, ultimately, SCE decided—rightly, in our opinion—to go forward with 250 MW of RSC contracts from this solicitation regardless of the outcome of the CPUC's RAM proceeding. A more qualified statement to prospective bidders—that SCE *may not* execute contracts—would have been more appropriate and would have been consistent with the position that SCE ultimately reached.

Overall, the IE's assessment is that the proposal evaluation process was fairly administered with respect to all proposals. Since there were no affiliate offers, issues associated with affiliate offers were not a factor in the assessment.

VI. Project-Specific Contract Negotiations

Of the contracts executed as a result of this solicitation, eight were RSC5 contracts and 13 were RSC20 contracts. The IE monitored the contract negotiations between SCE and the Offeror—under the RFO Participant Instructions limited to project-specific matters—and did not detect any unfairness on the part of SCE. SCE acted in an evenhanded manner and the parties reached agreement within a reasonable timeframe and contracts were executed by the target date set forth in the RFO Participant Guidelines. Further details are provided in the Confidential Appendix to this IE Report.

In addition, SCE negotiated contracts with provisionally shortlisted bidders with the understanding that those on the provisional shortlist would only obtain executed contracts if one or more projects on the shortlist dropped out or if SCE obtained, from its perspective, a favorable RAM decision. SCE presented this opportunity in a fair manner and acted consistently and responsively with those bidders on the provisional short list that chose to pursue this opportunity.

VII. Whether the Contracts Merit Approval and Other Matters

A. If Applicable, Describe Safeguards and Methodologies Employed by the IOU to Compare Affiliate Bids or Utility-Owned Generation Ownership Offers.

This was not applicable in this solicitation since utility-owned generation ownership offers were not eligible and no affiliate bids were submitted.

B. Based on the Complete Bid Process, are the IOU's Contracts the Best Overall Offers Received by the IOU?

From a price standpoint, lower priced bids would have been accepted for contract execution but for the 100 MW limit on supplier concentration. However, in the IE's opinion, it was reasonable for SCE to impose such a limit and within its discretion under the RFO Participant Instructions. In the future, however, supplier concentration limits (or criteria for determining those limits) should be set forth as part of the RFO design and communicated to prospective bidders before bids are submitted.

SCE, in the IE's opinion, also made assessments pertaining to project viability, although the depth of its inquiry was modest given the nature of the RSC RFO design, which is oriented toward simplicity, expedition, and low transaction costs. All in all, it is the IE's view that based on the entire solicitation process, SCE contracted for the best overall offers in the context of the guidelines set forth by SCE for the solicitation.

C. Did any Contract Reflect a Product Not Solicited and Bid in the RFO?

No.

D. Is the Contract a Reasonable Way of Achieving the Need Identified in the RFO?

The need identified in the RFO is to provide a process that will lead to quick execution of contracts for projects not greater than 20 MW. From the launch of the RSC RFO in early August 2010, it took approximately 3 and one-half months to hold two bidders conference (by web conference), obtain comments on the RSC pro forma contracts and then finalize them, receive a very large number of bids, evaluate the bids, short list bidders, and negotiate and execute 21 renewable standard contracts for 259 MW of renewable energy projects. This is an impressive feat. Based on the stated goals, the contracts are a reasonable way of achieving the need identified in the RFO.[36]

E. Do the Contracts Merit Commission Approval?

Based on our analysis of the RFO bids and the solicitation process, it is our opinion that the 20 contracts for which SCE is seeking approval warrant Commission approval. While the RSC RFO solicitation design and execution was not perfect, it was a reasonable means of testing the market, obtaining very attractive pricing, and applying modest but real viability criteria in the project evaluation. SCE acted fairly, in our opinion, in the evaluation and selection phases of the process. We also note that the results of the 2010 RSC were competitive with those projects on the 2009 RPS RFP

[36] One area for improvement is the process related to the drafting of the pro forma standard contracts, the finalization of the pro forma standard contracts and the negotiation of "project-specific" issues. This part of the process could be simplified and expedited if the utility were to start with a form of standard contract that is somewhat less complex and more "middle of the road."

shortlist based on the application of SCE's renewable premium analysis.[37] In our opinion, the resulting contracts merit approval.

VIII. Conclusions

For the reasons stated herein, Merrimack Energy concludes that the offer selection decisions by SCE in the 2010 Renewable Standard Contracts RFO process were reasonable and were based on the requirements and evaluation criteria set forth in the RFO Participant Instructions. The offers selected and contracts executed were the result of a competitive solicitation process with a highly robust response. In implementing the process, SCE was fair and reasonable to all Offerors and acted in an unbiased fashion. The information provided to prospective bidders through the two web conferences, questions and answers and other means of communication appeared to be very helpful to Offerors as a whole and were not provided preferentially to any Offeror. Merrimack Energy recommends approval of the 20 contracts executed by SCE through the 2010 RSC RFO process that are the subject of SCE's advice letter.

[37] The comparison is addressed in the confidential appendix to this report.

Appendix B
Description of Southern California Edison Company's Least Cost Best Fit Methodology Used in the 2009 Renewable Energy RFP

Overview

For the 2009 RPS RFP, SCE applied the Renewable Premium methodology as the primary evaluation metric to evaluate and rank proposals. The Renewable Premium is equal to levelized costs minus levelized benefits associated with each proposal in nominal $/MWh.

SCE has also developed a detailed process for evaluating and selecting proposals for the short list which is comprised of a number of pre-defined steps from receipt of bids through determination of the final short list. Prior to receiving proposals, SCE finalizes major assumptions and methodologies that drive the valuation, including power and natural gas price forecasts, existing and forecast resource portfolio, and firm capacity value forecast. Once proposals are received, SCE begins an initial review for completeness and conformity with the solicitation protocols. After the initial review is complete, SCE performs the quantitative assessment of each proposal individually. The result of the quantitative analysis is a relative ranking of proposals in preparation for selecting the preliminary short list. Proposals in the 2009 solicitation were evaluated and then ranked based on the Renewable Premium metric.

In parallel with the quantitative analysis, SCE conducts an assessment of each proposal's qualitative attributes. For the 2009 Renewable RFP, both SCE and the IE conducted a detailed evaluation of each proposal using the Commission's Project Viability Calculator. This analysis assesses a project's technical viability, development status and milestones and the developer's experience. These qualitative attributes are then considered to either eliminate non-viable proposals or add projects with high viability to the final short list of proposals. The Project Viability Calculator was not used with respect to the RSC applications.

Quantitative Assessment

SCE evaluates the quantifiable attributes and costs of each proposal individually and ranks proposals based on the Renewable Premium metric. For the quantitative analysis, benefits are comprised of separate capacity and energy components based on the calculated value of these products, while costs include the contract bid price, integration costs, transmission costs, performance assurance adder if applicable, and debt equivalence. SCE relies on the generation profile of the bid in its evaluation assessment. SCE discounts the annual benefit and cost streams to a common base year prior to calculating the Renewable Premium for each proposal. In developing its relative ranking of proposals, SCE's evaluation methodology incorporates information provided by the seller (such as the generation profile) and assumptions prescribed and set by the CPUC, with its own internal methodologies and forecasts of market conditions. The objective of the quantitative assessment and relative ranking is to develop a preliminary short list that is further refined based on non-quantifiable attributes.

Each of the components of the benefit and cost side of the analysis is described below. Both benefits and costs are levelized prior to calculating the Renewable Premium.

Benefits

Capacity Benefit

Each proposal is assigned capacity benefits based on SCE's forecast of net capacity value and a peak capacity contribution factor.

SCE's gross capacity value forecast consists of a combustion turbine ("CT") proxy. The CT proxy is based on the annual deferral value of a General Electric 7FA simple-cycle combustion turbine. The gross capacity value is then reduced by the expected profits that the assumed proxy plant would make from the energy markets to create the net capacity value.[1]

Peak capacity contribution factors are calculated in a manner consistent with the Commission's Resource Adequacy accounting rules (D.09-06-028) utilizing a 70% exceedance factor methodology. Peak capacity contribution factors will be both technology and location-specific. Technological differentiation does not refer to the fuel source, but rather the method of converting other energy sources into electricity (e.g., solar trough, photovoltaic). For proposals with dispatchable capabilities at SCE's control, the peak capacity contribution factor will be based on the availability of the proposed project.

Monthly capacity benefits are the product of SCE's net capacity value forecast, the total monthly proposed alternating current nameplate capacity of the project, SCE's relative loss-of-load probability factors, and the peak capacity contribution factor. The monthly capacity benefits are aggregated to annual capacity benefits.

Energy Benefit

SCE measures the energy benefits of a proposal by evaluating its effect on the total production cost of SCE's forecasted resource portfolio to serve its bundled customer load. The evaluation of the energy benefits is performed with a base portfolio and system that is consistent with SCE's most recent Long-Term Procurement Plan ("LTPP"), with some updates to account for the latest natural gas price and load forecast and the results of recent procurement activities.

SCE uses Ventyx's ProSym model to compare the hourly production costs of SCE's base resource portfolio with the hourly production costs when a baseload energy block is individually added to the base portfolio. Each energy block is added to the resource portfolio as a no-cost, must-take flat generation profile.

ProSym performs an hourly, least cost dispatch with SCE's known resource portfolio and generic generation to meet customer demand. Generic generation is added to the portfolio to ensure that RPS goals and resource adequacy requirements are satisfied and customer load can be met. A

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1 Energy profits are the difference between market revenues and variable cost of generation, as determined by performing a least-cost dispatch of the proxy station against SCE's power price forecast.

series of ProSym runs are performed with varying size blocks with the base proposal as the reference case. The ProSym runs consist of an hourly, least-cost dispatch of the base portfolio plus the generic energy block against SCE's current demand and price forecasts. The difference in hourly production costs between the two cases is the hourly energy benefit for each energy block. The energy benefit for each proposal is then calculated by taking the seller provided generation profile and interpolating the hourly energy benefit from the energy block runs. The difference between the interpolated hourly production cost and the reference case hourly production cost is the hourly energy benefit for the proposal.

SCE's resource portfolio is dispatched against an SCE area power price forecast. For out-of-area resource proposals, additional congestion charges may be added to calculate the net energy benefits based on SCE's internal congestion pricing forecasts. SCE's gas price forecast is based on a near-term market view and a longer-term fundamental view of prices, while power price forecasts are based on a fundamental view.[2]

Costs

1. Payments

The primary costs associated with each proposal are the payments that SCE pays to the seller for the expected renewable energy deliveries under the terms of the contracts. Proposals include an all-in price for delivered renewable energy, which is adjusted in each time-of-delivery period by energy payment allocation factors ("TOD factors"). The total estimated payments are then determined using the TOD-adjusted generation profile provided in the proposal and adjusted for electric energy loss factors (to calculate the delivered amount of electric energy).

2. Integration Costs

Integration costs are the additional system costs required to provide load following and regulation as a result of integrating various resources. The integration cost adder for all proposals is currently zero for purposes of calculating the Renewable Premium consistent with applicable CPUC rulings.[3]

3. Transmission Cost

For resources that do not have an existing interconnection to the electric system or a completed facility study, system transmission upgrade costs are estimated using SCE's Transmission Ranking Cost Report ("TRCR") methodology and specific details provided by Sellers in the RFP process. Network upgrade costs and scope from interconnection studies are used to the extent

[2] SCE's LCBF quantitative evaluation inherently captures the impact of portfolio fit. For example, as different proposals are added to the overall portfolio, the resultant residual short or net long position is impacted. Projects that more often increase SCE's net long positions are assigned less energy benefits than those projects that are more often filling net short positions. As such, a project that provides more energy when it is most needed and less energy in periods of low need will be evaluated as providing greater energy benefit.

[3] D.04-07-029, as clarified by D.07-02-011.

they are available and applicable. To the extent studies are not available, transmission cost adders for new generation are based on unit cost guides used in interconnection cluster studies.

Transmission cost adders were not used in the RSC evaluation or selection process. SCE estimated transmission cost adders for the Renewable Standard Contracts on a generalized basis for purposes of the renewable premium evaluation.

4. Debt Equivalence

"Debt Equivalence" is the term used by credit rating agencies to describe the fixed financial obligations resulting from long-term purchased power contracts. In November 2008, the CPUC issued D.08-11-008, which authorized the IOUs to recognize the effects of debt equivalence when comparing power purchase agreements in their bid evaluations, but not when a utility-owned generation project is being considered. Since no utility-owned generation was proposed in the 2009 RPS RFP, SCE considered debt equivalence as part of the evaluation.

Debt equivalence was not quantified or otherwise evaluated in the RSC evaluation or selection process. SCE has provided a Debt Equivalence evaluation for each Renewable Standard Contract as part of the Renewable Premium evaluation, which is set forth in Confidential Appendix A.

5. Credit and Collateral Requirements – Performance Assurance Adder

In the 2009 Renewable RFP, SCE requested that Sellers provide pricing based on the seller providing performance assurance during the operating period equal to 5% of contract payments.[4] The Company expressed a strong preference for this amount of performance assurance. However, Sellers had the option to propose different pricing for different performance assurance levels. SCE developed a methodology to assess the additional performance assurance exposure to SCE in cases where Sellers offered less than the proforma 5% performance assurance amount. SCE used this methodology to establish comparable pricing for use in ranking proposals.

Since for Renewable Standard Contracts of 5 MW and under no performance assurance was required and for over contracts up to 20 MW 5 percent performance assurance was required, performance assurance adders were inapplicable to either RSC evaluation/selection or the Renewable Premium assessments of these contracts.

Project Viability Assessment

To assess project viability in the Renewable RFP, SCE used the project viability calculator ("PVC") developed by the CPUC's Energy Division. The PVC contains three major evaluation categories and several sub-categories as criteria for evaluating bids. Also, each major category contains a weight for the major category overall. In addition, each criterion is ranked in one of four categories: (1) very high (in terms of importance); (2) high; (3) medium; and (4) low. The weights for each criteria range from 4 for the "very high" criteria to 1 for the "low" criteria. The

[4] For very short-term products, a different standard was set forth in the Procurement Protocol.

total project viability score for each bid is a function of the weight for the categories overall, the weights for each criteria and the score awarded for each bid within each criteria.

A list of the categories and criteria used in the project viability assessment is provided in Table 1 below:

Table 1 Project Viability Criteria

Category	Criteria
A. Company Development Team	
	1. Project Development Experience 2. Ownership/O&M Experience
B. Technology	.
	1. Technical Feasibility 2. Resource Quality 3. Manufacturing Supply Chain
C. Development Milestones	
	1. Site Control 2. Permitting Status 3. Project Finance Status 4. Interconnection Progress 5. Transmission Requirements 6. Reasonableness of COD

As mentioned previously, the PVC was not used for RSC applicants and project viability was not an eligibility requirement or an evaluation criterion. However, SCE has addressed project viability for the RSC projects in its advice letter filing and it is also addressed in our report.

<u>Other Qualitative Factors</u>

In addition to the identified benefits and costs that are quantified in the evaluation, SCE assesses in its Renewable RFP non-quantifiable characteristics of each proposal. These qualitative attributes are used to consider the inclusion of additional bids on the SCE short list or the exclusion of bids from the short list due to the relative weakness of highly ranked proposals due to (a) strength of a particular seller's proposal; or (b) the relative weakness of the high ranked proposals.

The attributes that SCE considers in the Renewable RFP context include, but are not limited to:

1. Extent of Seller's contractual concerns relating to SCE's Pro Forma Agreement;

2. SCE portfolio concentration risk;

3. Status of project development efforts;

4. Timing and progress towards gaining access to transmission;

5. Technology and economic viability, including viability and commercial experience of the technology;

6. Seller's capability to perform all of its financial and other obligations under the pro forma agreement;

7. Seller's ability to deliver energy in the near term; and

8. Performance assurance amount that the seller intends to post.

In addition, the 2009 Renewable RFP Procurement Protocol provides for SCE to assess additional non-quantifiable characteristics of each proposal that are used to determine tie-breakers. The pertinent attributes that SCE considers include, but are not limited to:

- If (i) the generating facility's first point of interconnection is within the Tehachapi area (namely, in the vicinity of the existing Antelope or Vincent substations; or in the vicinity of the future substations of Highwind, Windhub, Cottonwood, or Whirlwind); and (ii) such generating facility is dispatchable during on-peak periods;

- Environmental impacts of Seller's proposed project on California's water quality and use;

- Resource diversity;

- Benefit to minority and low income communities;

- Local reliability; and

- Environmental stewardship.

Pursuant to D.04-07-029, the presence of demonstrated qualitative attributes may justify moving a proposal onto SCE's short-list of proposals if (a) the initial proposal rank is within reasonable valuation proximity to those selected for the shortlist and (b) SCE receives support from its PRG to elevate the proposal based on qualitative factors.

Confidential Appendix D

Contract Summaries

Confidential Protected Materials – Public Disclosure Prohibited

Appendix E

RSC Contracts' Contribution to RPS Goals

Confidential Protected Materials – Public Disclosure Prohibited

Appendix F

SCE’s RPS Proposal Evaluation and Selection Process and Criteria

Southern California Edison Company's ("SCE") Written Description of Renewables Portfolio Standard ("RPS") Proposal Evaluation and Selection Process and Criteria ("LCBF Written Report")

I. Introduction

A. Note relevant language in statute and CPUC decisions approving LCBF process and requiring LCBF Reports

Under the direction of the California Public Utilities Commission (the "Commission" or "CPUC"), SCE conducts annual solicitations for the purpose of procuring power from eligible renewable energy resources to meet California's RPS. SCE evaluates and ranks proposals based on least-cost/best-fit ("LCBF") principles that comply with criteria set forth by the Commission in Decision ("D.") 03-06-071 and D.04-07-029 ("LCBF Decisions"). *See also* Pub. Util. Code Section 399.14(a)(2)(B).

B. Goals of proposal evaluation and selection criteria and processes

The LCBF analysis evaluates both quantitative and qualitative aspects of each proposal to estimate its value to SCE's customers and its relative value in comparison to other proposals.

II. Proposal Evaluation and Selection Criteria

While assumptions and methodologies have evolved slightly over time, the basic components of SCE's evaluation and selection criteria and process for RPS contracts were established by the Commission's LCBF Decisions. Consistent with those LCBF Decisions, the three main steps undertaken by SCE are: (i) initial data gathering and validation, (ii) a quantitative assessment of proposals, and (iii) adjustments to selection based on proposals' qualitative attributes.

Prior to receiving proposals, SCE finalizes major assumptions and methodologies that drive valuation, including power and gas prices forecasts, existing and forecast resource portfolio, and capacity value forecast. Other assumptions, such as the Transmission Ranking Cost Report ("TRCR"), are filed with the Commission for approval prior to the release of solicitation materials.

Once proposals are received, SCE begins an initial review for completeness and conformity with the solicitation protocol. The review includes an initial screen for required submission criteria such as conforming delivery point, minimum project size, and submission of particular proposal package elements. Sellers lacking in any of these items are allowed a cure period to remedy any deficiencies. Following this initial screen, SCE conducts an additional review to determine the reasonableness of proposal parameters such as generation profiles and capacity factors. SCE works directly with sellers to resolve any issues and ensure data is ready for evaluation.

After these reviews, SCE performs a quantitative assessment of each proposal individually and subsequently ranks them based on the proposal's benefit and cost relationship. Specifically, the total benefits and total costs are used to calculate the net levelized cost or "Renewable Premium" per each complete and conforming proposal. Benefits are comprised of separate capacity and energy components, while costs include the contract payments, integration costs, transmission cost, and debt equivalence. SCE discounts the annual benefit and cost streams to a common base year. The result of the quantitative analysis is a merit-order ranking of all complete and conforming proposals' Renewable Premiums that helps define the preliminary short list.

In parallel with the quantitative analysis, SCE conducts an in-depth assessment of each proposal's qualitative attributes. This analysis utilizes the Commission's prescribed Project Viability Calculator to assess certain factors including the company/development team, technology, and development milestones. Additional attributes such as transmission area/cluster, seller concentration, portfolio fit of commercial on-line date, project size, and dispatchability and curtailability are also considered in the qualitative analysis. These qualitative attributes are then considered to either eliminate non-viable proposals or add projects with high viability to the final short list of proposals, or to determine tie-breakers, if any.

Following its analysis, SCE consults with its Procurement Review Group ("PRG") regarding the final short list and specific evaluation criteria. Whether a proposal selected through this process results in an executed contract depends on the outcome of negotiations between SCE and sellers. Periodically, SCE updates the PRG regarding the progress of negotiations. SCE also consults with its PRG prior to the execution of any successfully negotiated contracts. Subsequently, SCE executes contracts and submits them to the Commission for approval via advice letter filings.

A. Description of Criteria[3]

1. List and discuss the quantitative and qualitative criteria used to evaluate and select proposals. This section should include a full discussion of the following:

<u>QUANTITATIVE ASSESSMENT</u>

SCE evaluates the quantifiable attributes of each proposal individually and subsequently ranks them based on the proposal's benefit and cost relationship, specifically the net levelized cost of the project or Renewable Premium. SCE maintains the same individual quantitative components it used in 2008 – capacity benefits, energy benefits, contract payments, debt equivalence mitigation costs, integration costs, and transmission costs. In developing its relative or merit order ranking of proposals, SCE's evaluation methodology incorporates information provided by sellers and assumptions prescribed and set by the Commission with its internal methodologies and forecasts of market conditions. The objective of the quantitative assessment and relative Renewable Premium ranking is to develop a preliminary short list that is further refined based on the non-quantifiable attributes discussed below. Each of the elements for the RPS quantitative analysis is described briefly below.

<u>Benefits</u>

- Capacity Benefit

Each proposal is assigned capacity benefits based on SCE's forecast of net capacity value and a peak capacity contribution factor.

SCE's gross capacity value forecast consists of a combustion turbine ("CT") proxy. The CT proxy is based on the annual deferral value of a General Electric 7FA simple-cycle combustion turbine. The gross

[3] This LCBF Written Report discusses SCE's proposal evaluation and selection criteria in a different order than in the Energy Division's LCBF Template in order to more accurately explain SCE's evaluation and selection process; however, all elements in the LCBF Template are addressed.

capacity value is then reduced by the expected profits that the assumed proxy plant would make from the energy markets to create the net capacity value.[4]

Peak capacity contribution factors are calculated in a manner consistent with the Commission's Resource Adequacy accounting rules (D.09-06-028) utilizing a 70% exceedance factor methodology. Peak capacity contribution factors will be both technology and location-specific. Technological differentiation does not refer to the fuel source, but rather the method of converting other energy sources into electricity (e.g., solar trough, photovoltaic). For proposals with dispatchable capabilities at SCE's control, the peak capacity contribution factor will be based on the availability of the proposed project.

Monthly capacity benefits are the product of SCE's net capacity value forecast, the total monthly proposed alternating current nameplate capacity of the project, SCE's relative loss-of-load probability factors, and the peak capacity contribution factor. The monthly capacity benefits are aggregated to annual capacity benefits.

- Energy Benefit

SCE measures the energy benefits of a proposal by evaluating its effect on the total production cost of SCE's forecasted resource portfolio to serve its bundled customer load. The evaluation of energy benefits is performed with a base portfolio and system that is consistent with SCE's most recent Long-Term Procurement Plan ("LTPP"), with some updates to account for the latest gas price and load forecasts and the results of recent procurement activities.

For proposals with must-take energy, SCE calculates the energy benefits of a proposal based on the impacts of additional blocks of no-cost, must-take, flat-profile energy on the hourly production cost as compared to the hourly production cost of SCE's base resource portfolio. The impacts are assessed through the use of Ventyx's ProSym model. A series of ProSym runs are performed with varying size blocks with the base portfolio, described above, as the reference case. The ProSym runs consist of an hourly, least-cost dispatch of the base portfolio plus the generic energy block against SCE's current demand and price forecasts. The hourly production cost for each proposal is then calculated by taking the seller provided generation for the hour and interpolating the hourly production cost based on the results of the generic energy block runs. The difference between the interpolated hourly production cost and the reference case hourly production cost is the hourly energy benefit for the proposal.

For proposals with dispatchable capabilities at SCE's control, SCE calculates the net energy benefits based on the impacts of the proposed additional resource on the hourly production cost as compared to the hourly production cost of SCE's base portfolio. ProSym is run with the base portfolio and the proposed resource to determine the annual production cost. The net energy benefits for the unit are calculated as the difference in annual production costs between the reference case and the proposed case.

SCE's resource portfolio is dispatched against an SCE area power price forecast. For out-of-area resource proposals, congestion charges may be applied to calculate the net energy benefits based on SCE's internal congestion pricing forecasts. SCE's gas price forecast is based on a near-term market view and a longer-term fundamental view of prices, while power price forecasts are based on a fundamental view.

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[4] Energy profits are the difference between market revenues and variable cost of generation, as determined by performing a least-cost dispatch of the proxy station against SCE's power price forecast.

The simulation model, and hence the energy benefit calculation, captures additional quantitative effects that SCE has been asked to consider by the Commission, including dispatchability. The dispatchability benefits are implied in the energy benefit and are not addressed separately.

SCE's LCBF quantitative evaluation process inherently captures the impact of portfolio fit. For example, as different proposals are added to the overall portfolio, the resultant residual net short or net long position is impacted. Projects that more often increase SCE's net long positions are assigned less energy benefits than those projects that are more often filling net short positions. As such, a project that provides more energy when it is most needed and less energy in periods of low need will receive the greatest energy benefit.

Costs

- Debt Equivalence

"Debt equivalence" is the term used by credit rating agencies to describe the fixed financial obligation resulting from long-term purchased power contracts. Pursuant to D.04-12-048, the Commission permitted the utilities to recognize costs associated with the effect debt equivalence has on the utilities' credit quality and cost of borrowing in their evaluation process. In D.07-12-052, the Commission reversed this position. However, SCE filed a petition for modification of D.07-12-052. In November 2008, the Commission issued D.08-11-008, which authorized the investor-owned utilities ("IOUs") to recognize the effects of debt equivalence when comparing power purchase agreements in their bid evaluations, but not when a utility-owned generation project is being considered. Given the new decision, SCE considers debt equivalence in the evaluation process.

- Contract Payments

The primary costs associated with each proposal are the contract payments that SCE makes to sellers for the expected renewable energy deliveries.

Proposals typically include an all-in price for delivered renewable energy, which is adjusted in each time-of-delivery period by energy payment allocation factors ("TOD factors"). SCE develops and submits its TOD factors for each solicitation to the Commission for approval prior to the issuance of the Request for Proposals ("RFP"). Total payments are then determined using the TOD adjusted generation, based on the generation profile provided in the proposal, and the contract price. For projects that include a capacity-related payment in addition to an energy price, the total payments are determined by using the TOD adjusted generation based on the generation profile provided in the proposal, the energy price, and the capacity payment.

- Integration Costs

Integration costs are the additional system costs required to provide load following and regulation as a result of integrating various resources. Pursuant to D.04-07-029, as clarified in D.07-02-011, the integration cost adder for all proposals is zero.

- Transmission Cost

For resources that do not have an existing interconnection to the electric system or a completed facilities study, system transmission upgrade costs are estimated utilizing the TRCR methodology and specific proposal details provided by sellers in the RFP process. Network upgrade costs and scope from interconnection studies are used to the extent they are available and applicable. To the extent studies are not available, transmission cost adders for new generation are based on unit cost guides used in interconnection cluster studies.

- **Discuss how much detailed transmission cost information the IOU requires for each project**

Other than the assumptions provided in a seller's proposal, SCE does not require additional transmission information, unless the seller has completed a transmission provider study. If one or more transmission provider studies have been completed with respect to the proposed project, then the seller must provide the results.

- **Discuss whether cost adders are always imputed for projects in transmission-constrained areas, or whether and how costs for alternative commercial transactions (i.e., swapping, remarketing) are substituted**

SCE uses the best available information it can find when determining the cost of potential upgrades for projects in transmission-constrained areas. For those projects outside SCE's service area, the TRCRs of Pacific Gas and Electric Company or San Diego Gas & Electric Company are used as appropriate. SCE applies the required upgrade costs to get the project delivered to the nearest defined market (e.g., NP15, SP15, ZP 26 Generation Trading Hubs). For projects with an assumed delivery point outside the California Independent System Operator ("CAISO"), SCE applies a power swapping methodology, where the power is assumed to be sold into the local market.

QUALITATIVE ASSESSMENT

In addition to the benefits and costs quantified during SCE's evaluation, SCE assesses non-quantifiable characteristics of each proposal by conducting a comprehensive analysis of each project's qualitative attributes. These qualitative attributes are used to consider inclusion of additional sellers on the short list due to the strength of a particular seller's proposal. Pursuant to D.04-07-029, the presence of demonstrated qualitative attributes may justify moving a proposal onto SCE's short list of proposals if (a) the initial proposal rank is within reasonable valuation proximity to those selected for the short list and (b) SCE consults with, and receives general support from, its PRG prior to elevating the proposal based on qualitative factors.

This assessment may also result in the exclusion of proposals from the short list due to the relative weakness of highly-ranked proposals or other identified issues such as potential seller and/or supply chain concentration concerns.

In other instances, where there are weaknesses in some of these factors (although these may not be significant enough to exclude a proposal from the short list), SCE utilizes additional contract requirements to manage these issues during the development of the project.

Each of the elements for the qualitative analysis is described briefly below.

Project Viability

SCE assesses the following attributes using the Commission's prescribed Project Viability Calculator:

- Company/Development Team
  - Project Development Experience
  - Ownership/O&M Experience
- Technology
  - Technical Feasibility
  - Resource Quality
  - Manufacturing Supply Chain
- Development Milestones
  - Site Control
  - Permitting Status
  - Project Financing Status
  - Interconnection Progress
  - Transmission Requirements
  - Reasonableness of Commercial Operation Date ("COD")

Additional Qualitative Attributes

Following the Project Viability Calculator qualitative assessment, SCE considers additional qualitative characteristics to determine advancement onto the short list or tie-breakers, if any. These additional characteristics may include:

- Transmission area (e.g., Tehachapi, Sunrise, within SCE's load pocket)
- Portfolio fit of COD
- Seller concentration
- Expected generation (GWh/year)
- Dispatchability and curtailability
- Contract price
- Alternative Renewable Premium (i.e., Renewable Premium including integration costs)
- Environmental impacts of seller's proposed project on California's water quality and use
- Resource diversity
- Benefits to minority and low income communities
- Local reliability
- Environmental stewardship

OTHER CONSIDERATIONS

Out-of-State Projects

- **Discuss how evaluation process differs for out-of-state projects**

The overall evaluation methodology is applied consistently to projects regardless of location. Energy benefits for those projects outside of the CAISO will be based on the pricing at the seller-elected liquid trading hub or CAISO intertie according to SCE's fundamental price forecast for hubs across the Western Electricity Coordinating Council ("WECC"). For projects that deliver at the busbar, SCE will evaluate the energy benefits based upon the regional price forecast where the energy is likely to be managed. Capacity benefits will be based on SCE's forecast of the regional capacity value, the nameplate capacity of the project, and the peak capacity contribution factor of the project.

For those projects within or connected directly to the CAISO, SCE applies the cost to customers of new CAISO network upgrades required for deliverability of the new project. SCE customers are not liable for any network upgrades outside of the CAISO (outside of any costs that may be imbedded within the contract pricing) so transmission cost adders are zero for out-of-state projects.

B. Criteria Weightings

1. If a weighting system is used, please describe how each LCBF component is assigned a quantitative or qualitative weighting compared to other components. Discuss the rationale for the weightings.

SCE does not apply a weighing system in its LCBF evaluation.

2. If a weighting system is not used, please describe how the LCBF evaluation criteria are used to rank proposals

SCE's LCBF quantitative evaluation of the proposals incorporates energy and capacity benefits with contract payments, transmission and integration costs, and debt equivalence to create individual benefit and cost relationships, namely, the Renewable Premium. It is the Renewable Premium that is used to rank and compare each project. Qualitative attributes of each proposal are then considered to further screen the short list and determine tie-breakers to arrive at a final short list of proposals.

3. Discuss how the IOU LCBF methodology evaluates project commercial operation date relative to transmission upgrades required for the project

As part of the qualitative assessment, SCE considers sellers' proposed on-line dates for the project in conjunction with a variety of critical project milestones. Such milestones include network upgrade status and scope, status of major equipment procurement and lead times, and permitting status. For those projects which SCE has concerns over the viability of the timeframe, a range of on-line dates (and transmission facilities availability) are evaluated to determine the sensitivity of the results to the timing. If the project ranking does not change in a manner that would change its original selection status over a range that SCE deems reasonable, then the original assessment is used. For projects whose selection is dependent on the timing of the project and the availability of upgraded transmission facilities, further analysis of the timing of the projects is required.

4. Discuss how the LCBF methodology takes into account proposals that may be more expensive, but have a high likelihood of resulting in viable projects

SCE's LCBF methodology incorporates project viability in a qualitative assessment after the preliminary ranking of proposals has been completed and in determining the size of the short list. Proposals that are more expensive tend to be lower on the quantitative ranking of projects, and, therefore, may fall beyond the initial short list cut-point. SCE may pull such projects onto the short list if, from its qualitative assessment, it determines the project maintains high viability and the initial proposal rank is within reasonable valuation proximity to those selected for the short list. In this situation, the quantitative ranking is still considered as part of the overall decision, but the viability becomes the key driver.

C. Evaluation of utility-owned, turnkey, buyouts, and utility-affiliate projects

1. Describe how utility-owned projects are evaluated against power purchase agreements ("PPAs")

SCE views utility-owned cost-of-service generation as a necessary and good option for customers to have. SCE does not evaluate proposed utility-owned projects against PPAs, as utility-owned generation and contracted-for generation are fundamentally different products. As such, any attempt to do a numerical comparison of them is unworkable. This topic is discussed in detail in the Supplemental Testimony to SCE's 2006 LTPP (Section I.B, pgs 2-5). Moreover, approval of a utility-owned project would not be submitted through the solicitation process, but through a formal application.

2. Describe how turnkey projects are evaluated against PPAs

Turnkey projects are similar to utility-owned projects. Refer to the response above.

3. Describe how buyout projects are evaluated against PPAs

The 2009 RFP Procurement Protocol specified that the objective of the solicitation was to purchase the output from projects developed and owned by independent power producers. SCE received an overwhelming response of proposals from independent power producers consistent with this type of structure. SCE did receive one proposal for a design, build, buyout, but that proposal was subsequently withdrawn by the seller after a discussion between SCE and the seller.

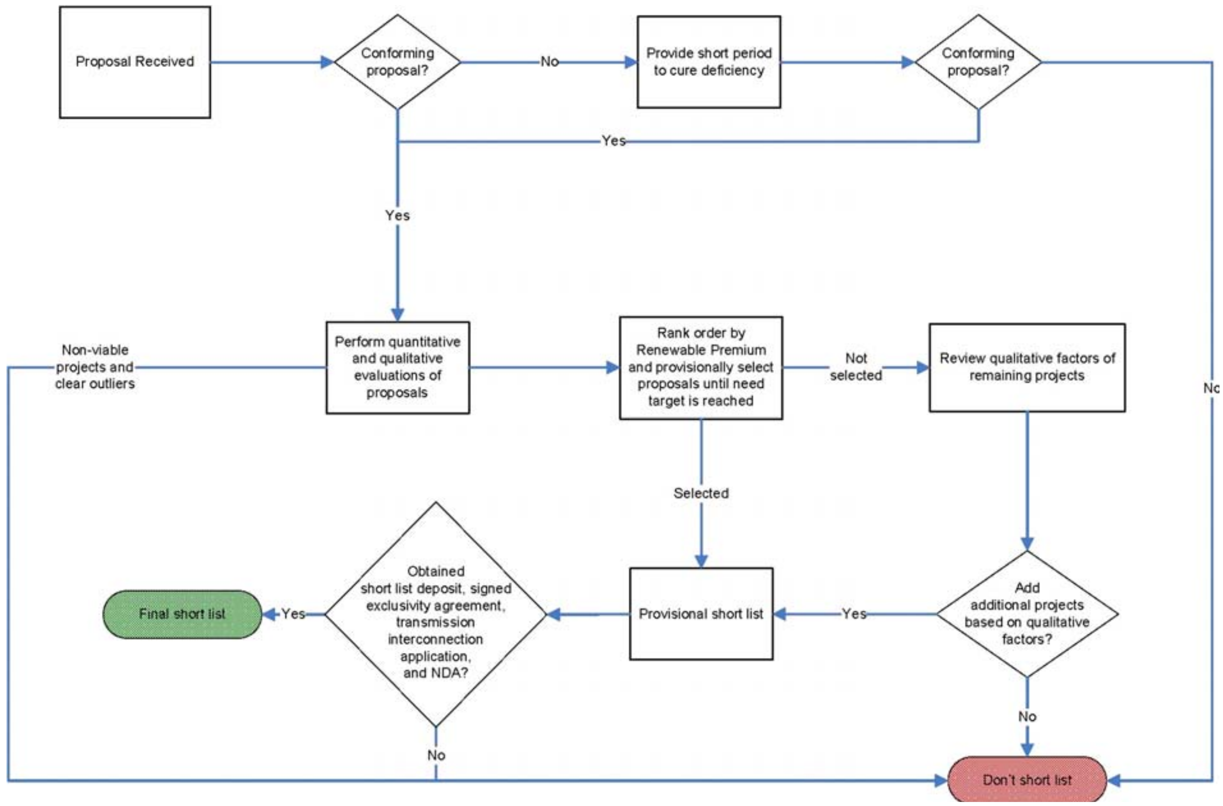
4. Describe how utility-affiliate projects are evaluated against non-affiliate projects

Utility-affiliate projects are evaluated in the same manner as non-affiliate projects. In addition, evaluation of utility affiliate projects would be subject to review by the Independent Evaluator, the PRG, and the Commission through the application approval process.

II. <u>Proposal Evaluation and Selection Process</u>

A. What is the process by which proposals are received and evaluated, selected or not selected for short list inclusion, and further evaluated once on the short list?

2009 RPS RFP Short-List Process



B. What is the typical amount of time required for each part of the process?

The typical amount of time required for the short listing process depends on the volume of proposals received by SCE during a solicitation. Historically, it has taken SCE no more than eight weeks to complete the LCBF evaluation process, which includes quality control of sellers' information, transmission assessment, quantitative assessment, qualitative assessment, management review, and PRG meetings. Many of the components in the overall process overlap and may require additional time if clarification from sellers is needed.

C. How is the size of the short list determined?

The size of SCE's short list is determined largely by an assessment of the attractiveness of RPS-eligible energy proposals and a desire for a robust, inclusive set of developer proposals. The short list is expanded well beyond the point that is needed for SCE to meet its RPS goals, as there is an expectation that some projects that are selected will not join the short list and that negotiations will not be successful with some short listed sellers.

D. Are sellers that are not selected to be short listed told why they were not short listed? If so, what is the process?

Sellers are informed by e-mail that their proposals were not short listed. The e-mail does not contain specific reasons for a seller's proposal not being selected for short listing. However, sellers often contact

SCE to obtain specificity regarding their projects and what can be improved for future solicitations. In such cases, SCE refers the seller to the RFP documentation in conjunction with a discussion of the seller's project quantitative and qualitative scoring.

E. Were any proposals rejected for non-conformance? If so, how many and what were the non-conforming characteristics?

SCE did not reject any proposals as non-conforming.

F. Describe involvement of the Independent Evaluator

The Independent Evaluator monitors SCE's RPS solicitations, provides an independent review of SCE's process, models, assumptions, and the proposals it may receive, and helps the Commission and SCE's PRG participants by providing them with information and assessments to ensure that the solicitation was conducted fairly and that the most appropriate resources were short listed. The Independent Evaluator also provides an assessment of SCE's RPS solicitation from the initial phase of the solicitation (i.e., the publicizing of the issuance of the RFP) through the development of a short list of proposals with whom SCE has commenced negotiations.

G. Describe involvement of the Procurement Review Group

SCE consults with its PRG during each step of the renewable procurement process. Among other things, SCE provides access to the solicitation materials and pro forma contracts to the PRG for review and comment before commencing the RFP; informs the PRG of the initial results of the RFP; explains the evaluation process; and updates the PRG periodically concerning the status of contract formation.

H. Discuss whether and how feedback on the solicitation process is requested from sellers (both successful and unsuccessful) after the solicitation is complete

SCE regularly receives feedback during the normal course of its solicitation process. Shortly after the 2009 RPS RFP bidders conference, SCE solicited feedback from participants via a web based survey. The results of this feedback was shared with SCE's PRG. In addition, SCE anticipates it will formally solicit feedback either through a survey, workshop or other similar method from participants in the 2009 solicitation.

Appendix G

AMF Calculators

Confidential Protected Materials – Public Disclosure Prohibited

Appendix H.1

Lancaster Dry Farm Ranch B PPA

Confidential Protected Materials – Public Disclosure Prohibited

Appendix H.2

Comparison of Lancaster Dry Farm Ranch B PPA to 2010 RSC Pro Forma

Confidential Protected Materials – Public Disclosure Prohibited

Appendix I.1

Sierra Solar Greenworks PPA

Confidential Protected Materials – Public Disclosure Prohibited

Appendix I.2

Comparison of Sierra Solar Greenworks PPA to 2010 RSC Pro Forma

Confidential Protected Materials – Public Disclosure Prohibited

Appendix J.1

Lancaster WAD B PPA

Confidential Protected Materials – Public Disclosure Prohibited

Appendix J.2

Comparison of Lancaster WAD B PPA to 2010 RSC Pro Forma

Confidential Protected Materials – Public Disclosure Prohibited

Appendix K.1

Central Antelope Dry Ranch B PPA

Confidential Protected Materials – Public Disclosure Prohibited

Appendix K.2

Comparison of Central Antelope Dry Ranch B PPA to 2010 RSC Pro Forma

Confidential Protected Materials – Public Disclosure Prohibited

Appendix L.1

Central Antelope Dry Ranch C PPA

Confidential Protected Materials – Public Disclosure Prohibited

Appendix L.2

Comparison of Central Antelope Dry Ranch C PPA to 2010 RSC Pro Forma

Confidential Protected Materials – Public Disclosure Prohibited

Appendix M.1

Victor Dry Farm Ranch A PPA

Confidential Protected Materials – Public Disclosure Prohibited

Appendix M.2

Comparison of Victor Dry Farm Ranch A PPA to 2010 RSC Pro Forma

Confidential Protected Materials – Public Disclosure Prohibited

Appendix N.1

Victor Dry Farm Ranch B PPA

Confidential Protected Materials – Public Disclosure Prohibited

Appendix N.2

Comparison of Victor Dry Farm Ranch B PPA to 2010 RSC Pro Forma

Confidential Protected Materials – Public Disclosure Prohibited

Appendix O.1

North Lancaster Ranch PPA

Confidential Protected Materials – Public Disclosure Prohibited

Appendix O.2

Comparison of North Lancaster Ranch PPA to 2010 RSC Pro Forma

Confidential Protected Materials – Public Disclosure Prohibited

Appendix P.1

American Solar Greenworks PPA

Confidential Protected Materials – Public Disclosure Prohibited

Appendix P.2

Comparison of American Solar Greenworks PPA to 2010 RSC Pro Forma

Confidential Protected Materials – Public Disclosure Prohibited

Appendix Q.1

Sierra View Solar V PPA

Confidential Protected Materials – Public Disclosure Prohibited

Appendix Q.2

Comparison of Sierra View Solar V PPA to 2010 RSC Pro Forma

Confidential Protected Materials – Public Disclosure Prohibited

Appendix R.1

Sierra View Solar IV PPA

Confidential Protected Materials – Public Disclosure Prohibited

Appendix R.2

Comparison of Sierra View Solar IV PPA to 2010 RSC Pro Forma

Confidential Protected Materials – Public Disclosure Prohibited

Appendix S.1

Nicolis PPA

Confidential Protected Materials – Public Disclosure Prohibited

Appendix S.2

Comparison of Nicolis PPA to 2010 RSC Pro Forma

Confidential Protected Materials – Public Disclosure Prohibited

Appendix T.1

Blythe Solar Power Generation Station 1 PPA

Confidential Protected Materials – Public Disclosure Prohibited

Appendix T.2

Comparison of Blythe Solar Power Generation Station 1 PPA to 2010 RSC Pro Forma

Confidential Protected Materials – Public Disclosure Prohibited

Appendix U.1

Littlerock Solar Power Generation Station 1 PPA

Confidential Protected Materials – Public Disclosure Prohibited

Appendix U.2

Comparison of Littlerock Solar Power Generation Station 1 PPA to 2010 RSC Pro Forma

Confidential Protected Materials – Public Disclosure Prohibited

Appendix V.1

Garnet Solar Power Generation Station 1 PPA

Confidential Protected Materials – Public Disclosure Prohibited

Appendix V.2

Comparison of Garnet Solar Power Generation Station 1 PPA to 2010 RSC Pro Forma

Confidential Protected Materials – Public Disclosure Prohibited

Appendix W.1

Lucerne Solar Power Generation Station 1 PPA

Confidential Protected Materials – Public Disclosure Prohibited

Appendix W.2

Comparison of Lucerne Solar Power Generation Station 1 PPA to 2010 RSC Pro Forma

Confidential Protected Materials – Public Disclosure Prohibited

Appendix X.1

Tropico PPA

Confidential Protected Materials – Public Disclosure Prohibited

Appendix X.2

Comparison of Tropico PPA to 2010 RSC Pro Forma

Confidential Protected Materials – Public Disclosure Prohibited

Appendix Y.1

Clear Peak Energy PPA

Confidential Protected Materials – Public Disclosure Prohibited

Appendix Y.2

Comparison of Clear Peak Energy PPA to 2010 RSC Pro Forma

Confidential Protected Materials – Public Disclosure Prohibited

Appendix Z.1

RE Columbia 3 PPA

Confidential Protected Materials – Public Disclosure Prohibited

Appendix Z.2

Comparison of RE Columbia 3 PPA to 2010 RSC Pro Forma

Confidential Protected Materials – Public Disclosure Prohibited

Appendix AA.1

RE Columbia Two PPA

Confidential Protected Materials – Public Disclosure Prohibited

Appendix AA.2

Comparison of RE Columbia Two PPA to 2010 RSC Pro Forma

Confidential Protected Materials – Public Disclosure Prohibited

Appendix BB

Project Viability Calculators

Confidential Protected Materials – Public Disclosure Prohibited

Appendix CC

Confidentiality Declaration

DECLARATION OF GEORGE WILTSEE REGARDING THE CONFIDENTIALITY OF CERTAIN DATA

I, George Wiltsee, declare and state:

1. I am an Energy Contract/Trading Specialist in the Renewable and Alternative Power department of Southern California Edison Company ("SCE"). As such, I had responsibility for preparing and supervising the preparation of this Advice Letter ("Protected Materials"). I make this declaration in accordance with Decision ("D.") 06-06-066, the Administrative Law Judge's Ruling Clarifying Interim Procedures for Complying with D.06-06-066, issued on August 22, 2006 in California Public Utilities Commission ("Commission" or "CPUC") Rulemaking ("R.") 05-06-040, and D.08-04-023. I have personal knowledge of the facts and representations herein and, if called upon to testify, could and would do so, except for those facts expressly stated to be based upon information and belief, and as to those matters, I believe them to be true.

2. I have reviewed the Protected Materials. Listed below are the data in the Protected Materials for which SCE is seeking confidential protection and the categories on the Matrix of Allowed Confidential Treatment Investor Owned Utility ("IOU") Data ("Matrix") to which these data correspond.

Data	Page	Matrix Category	Period of Confidentiality
Consistency with Commission Decisions and Rules and Project Development Status	Appendix A	VII.F/VII.G RPS Contracts VII.H Score sheets, analyses, evaluations of proposed RPS projects VIII.A Bid Information VIII.B Specific quantitative	RPS contracts confidential for three years, or until one year following expiration, whichever comes first. Score sheets, analyses, evaluations of proposed RPS projects confidential for three years. For bid information,

		analysis involved in the scoring and evaluation of participating bids	total number of projects and megawatts bid by resource type public after final contracts submitted to CPUC for approval. Specific quantitative analysis involved in the scoring and evaluation of participating bids confidential for three years after winning bidders selected.
2010 RSC Program Solicitation Overview and 2009 Solicitation Workpapers	Appendix B	VII.F/VII.G RPS Contracts VII.H Score sheets, analyses, evaluations of proposed RPS projects VIII.A Bid Information VIII.B Specific quantitative analysis involved in the scoring and evaluation of participating bids	RPS contracts confidential for three years, or until one year following expiration, whichever comes first. Score sheets, analyses, evaluations of proposed RPS projects confidential for three years. For bid information, total number of projects and megawatts bid by resource type public after final contracts submitted to CPUC for approval. Specific quantitative analysis involved in the scoring and evaluation of participating bids confidential for three years after winning bidders selected.
Independent Evaluator Report	Confidential Version of Appendix C	VII.F/VII.G RPS Contracts VII.H Score sheets, analyses, evaluations of proposed RPS projects	RPS contracts confidential for three years, or until one year following expiration, whichever comes first. Score sheets, analyses,

		VIII.A Bid Information VIII.B Specific quantitative analysis involved in the scoring and evaluation of participating bids	evaluations of proposed RPS projects confidential for three years. For bid information, total number of projects and megawatts bid by resource type public after final contracts submitted to CPUC for approval. Specific quantitative analysis involved in the scoring and evaluation of participating bids confidential for three years after winning bidders selected.
Confidential Contract Summaries	Confidential Appendix D	VII.F/VII.G RPS Contracts VII.H Score sheets, analyses, evaluations of proposed RPS projects VIII.A Bid Information VIII.B Specific quantitative analysis involved in the scoring and evaluation of participating bids	RPS contracts confidential for three years, or until one year following expiration, whichever comes first. Score sheets, analyses, evaluations of proposed RPS projects confidential for three years. For bid information, total number of projects and megawatts bid by resource type public after final contracts submitted to CPUC for approval. Specific quantitative analysis involved in the scoring and evaluation of participating bids confidential for three years after winning bidders selected.

RSC Contracts' Contribution To RPS Goals	Confidential Appendix E	V.C LSE Total Energy Forecast – Bundled Customer	LSE total energy forecast – bundled customer front three years of forecast data confidential.
AMF Calculators for the RSC Contracts	Confidential Appendix G	VII.F/VII.G RPS Contracts VII.H Score sheets, analyses, evaluations of proposed RPS projects VIII.B Specific quantitative analysis involved in the scoring and evaluation of participating bids	RPS contracts confidential for three years, or until one year following expiration, whichever comes first. Score sheets, analyses, evaluations of proposed RPS projects confidential for three years. Specific quantitative analysis involved in the scoring and evaluation of participating bids confidential for three years after winning bidders selected.
Power Purchase Agreements for RSC Contracts between SCE and Various Sellers/Comparisons of RSC Contracts to 2010 RSC Pro Forma	Confidential Appendices H.1-AA.2	VII.F/VII.G RPS Contracts	RPS contracts confidential for three years, or until one year following expiration, whichever comes first.
Project Viability Calculators[1]	Confidential Appendix BB	VII.F/VII.G RPS Contracts VII.H Score sheets, analyses, evaluations of proposed RPS projects VIII.B Specific quantitative analysis involved in the scoring and evaluation	RPS contracts confidential for three years, or until one year following expiration, whichever comes first. Score sheets, analyses, evaluations of proposed RPS projects confidential for three years.

[1] The Commission concluded that project-specific project viability information should remain confidential in D.09-06-018.

		of participating bids	Specific quantitative analysis involved in the scoring and evaluation of participating bids confidential for three years after winning bidders selected.

3. SCE is complying with the limitations on confidentiality specified in the Matrix that pertain to the data listed in the table above.

4. I am informed and believe and thereon allege that the data in the table above cannot be aggregated, redacted, summarized, masked or otherwise protected in a manner that would allow partial disclosure of the data while still protecting confidential information.

5. I am informed and believe and thereon allege that the data in the table in paragraph 2 above has never been made publicly available.

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

Executed on January 27, 2011, at Rosemead, California.

George Wiltsee

Appendix DD

Proposed Protective Order

BEFORE THE PUBLIC UTILITIES COMMISSION

OF THE STATE OF CALIFORNIA

Submission of Contracts for Procurement of Renewable Energy Resulting From Renewables Standard Contracts Program	)))))	**Advice 2547-E**

PROTECTIVE ORDER

1. Scope. This Protective Order shall govern access to and the use in this proceeding of Protected Materials, produced by, or on behalf of, any Disclosing Party.

2. Modification. This Protective Order shall remain in effect until it is modified or terminated by the Commission or Assigned Administrative Law Judge ("Assigned ALJ"). The parties acknowledge that the identity of the parties submitting Protected Materials may differ from time to time. In light of this situation, the parties agree that modifications to this Protective Order may become necessary, and they further agree to work cooperatively to devise and implement such modifications in as timely a manner as possible. Each party governed by this Protective Order has the right to seek changes in it as appropriate from the Assigned ALJ or the Commission.

3. Definitions.

A. The term "Protected Material(s)" means (i) trade secret, market sensitive, or other confidential and/or proprietary information as determined by the Disclosing Party in accordance with the provisions of D.06-06-066 and subsequent decisions, General Order 66-C and Public Utilities Code Section 454.5(g), or any other right of confidentiality provided by law, or (ii) any other materials that are made subject to this Protective Order by the Assigned ALJ, Law and Motion Administrative Law Judge ("Law and Motion ALJ"), Assigned Commissioner, the Commission, or any court or other body having appropriate authority. Protected Materials also includes memoranda, handwritten notes, spreadsheets, computer files and reports, and any other form of information (including information in electronic form) that copies, discloses, or compiles other Protected Materials or from which such materials may be derived (except that any derivative materials must be separately shown to be confidential). Protected Materials do not include: (i) any information or document contained in the public files of the CPUC or any other state or federal agency, or in any state or federal court; or (ii) any information that is public knowledge, or which becomes public knowledge, other than through disclosure in violation of this Protective Order or any other protective order.

B. The term "redacted" refers to situations in which Protected Materials in a document, whether the document is in paper or electronic form, have been covered, blocked out, or removed. The term "unredacted" refers to situations in which the Protected Materials in a document, whether in paper or electronic form, have not been covered, blocked out, or removed.

C. The term "Disclosing Party" means a party who initially discloses any specified Protected Materials in this proceeding.

D. The term "Market Participant" ("MP") refers to a party that is:

1) A person or entity, or an employee of an entity, that engages in the wholesale purchase, sale or marketing of energy or capacity, or the bidding on or purchasing of power plants, or bidding on utility procurement solicitations, or consulting on such matters, subject to the limitations in 3) below.

2) A trade association or similar organization, or an employee of such organization,

   a) whose primary focus in proceedings at the Commission is to advocate for persons/entities that purchase, sell or market energy or capacity at wholesale; bid on, own, or purchase power plants; or bid on utility procurement solicitations; or

   b) a majority of whose members purchase, sell or market energy or capacity at wholesale; bid on, own, or purchase power plants; or bid on utility procurement solicitations; or

   c) formed for the purpose of obtaining market sensitive information; or

d) controlled or primarily funded by a person or entity whose primary purpose is to purchase, sell or market energy or capacity at wholesale; bid on, own, or purchase power plants; or bid on utility procurement solicitations.

3) A person or entity that meets the criteria of 1) above is nonetheless not a market participant for purpose of access to market sensitive data unless the person/entity seeking access to market sensitive information has the potential to materially affect the price paid or received for electricity if in possession of such information. An entity will be considered not to have such potential if:

a) the person or entity's participation in the California electricity market is *de minimis* in nature. In the resource adequacy proceeding (R.05-12-013) it was determined in D.06-06-064 § 3.3.2 that the resource adequacy requirement should be rounded to the nearest megawatt (MW), and load serving entities (LSEs) with local resource adequacy requirements less than 1 MW are not required to make a showing. Therefore, a *de minimis* amount of energy would be less than 1 MW of capacity per year, and/or an equivalent of energy; and/or

b) the person or entity has no ability to dictate the price of electricity it purchases or sells because such price is set by a process over which the person or entity has no control, *i.e.*, where the prices for power put to the grid are completely overseen by the Commission, such as subject to a standard offer contract or tariff price. A person or entity that currently has no ability to dictate the price of electricity it purchases or sells under this section, but that will have such ability within one year because its contract is expiring or other circumstances are changing, does not meet this exception; and/or

c) the person or entity is a cogenerator that consumes all the power it generates in its own industrial and commercial processes, if it can establish a legitimate need for market sensitive information.

E. A Market Participant's Reviewing Representatives are limited to persons designated by the Market Participant who meet the following criteria:

1. Are outside experts, consultants or attorneys;

2. Are not currently engaged, directly or indirectly, in (a) the purchase, sale, or marketing of electrical energy or capacity or natural gas (or the direct supervision of any employee(s) whose duties include such activities), (b) the bidding on or purchasing of power plants (or the direct supervision of any employee(s) whose duties include such activities), or (c) consulting with or advising

others in connection with any activity set forth in subdivisions (a) or (b) above (or the direct supervision of any employee(s) whose duties include such activities or consulting); and

3. Are not an employee of a market participant.

F. Persons or entities that do not meet the definition of market participant are non-market participants ("NMPs"), and may have access to market sensitive information through their designated Reviewing Representatives. An attorney or consultant that simultaneously represents market participant(s) and non-market participant(s) may not have access to market sensitive data. If, on the other hand, simultaneous representation is of market participant and non-market participant clients involved in completely different types of matters, there should be no bar (although there may be ethical implications of such representation that we do not address here). If, for example, an attorney represents a market participant in matters unrelated to procurement, resource adequacy, RPS, or the wholesale purchase, sale or marketing of energy or capacity, or the bidding on or purchasing of power plants, or bidding on utility procurement solicitations, in a forum other than this Commission, and simultaneously represents a non-market participant in cases related to these topics before the Commission, there should be no bar to the attorney's receipt of market sensitive data (pursuant to a non-disclosure agreement and protective order) in the latter matter. In close cases, the balance should militate to bar simultaneous representation because of the risks it poses.

H. All Reviewing Representatives are required to execute a non-disclosure agreement and are bound by the terms of this Protective Order.

4. Designation of Materials.

When filing or providing in discovery any documents containing Protected Materials, a party shall physically mark such documents on each page (or in the case of non-documentary materials such as computer diskettes, on each item) as "PROTECTED MATERIALS SUBJECT TO PROTECTIVE ORDER," or with words of similar import as long as one or more of the terms, “Protected Materials,” “Protective Order,” or “General Order No. 66-C” is included in the designation to indicate that the materials in question are protected.

All materials so designated shall be treated as Protected Materials unless and until (a) the designation is withdrawn pursuant to Paragraph 17 hereof, or (b) an ALJ, Commissioner or other Commission representative makes a determination pursuant to Paragraph 4 hereof changing the designation.

All documents containing Protected Materials that are filed with the Commission or served shall be placed in sealed envelopes or otherwise appropriately protected and shall be endorsed to the effect that they are filed or served under seal pursuant to this Protective Order. Such documents shall be served upon Reviewing Representatives and persons employed by or working on behalf of the state governmental agencies referred to in Paragraph 12 hereof who are eligible and have requested to review such materials. Service upon the persons specified in the foregoing sentence may either be (a) by electronic mail in accordance with the procedures adopted in this proceeding, (b) by facsimile, or (c) by overnight mail or messenger service. Whenever service of a document containing Protected Materials is made by overnight mail or messenger service, the Assigned ALJ shall be served with such document by hand on the date that service is due.

5. Redaction of Documents. Whenever a party files, serves or provides in discovery a document that includes Protected Materials (including but not limited to briefs, testimony, exhibits, and responses to data requests), such party shall also prepare a redacted version of such document. The redacted version shall enable persons familiar with this proceeding to determine with reasonable certainty the nature of the data that has been redacted and where the redactions occurred. The redacted version of a document to be filed shall be served on all persons on the service list, and the redacted version of a discovery document shall be served on all persons entitled thereto.

6. Selection of Reviewing Representatives. Each MP and NMP selecting a Reviewing Representative shall first identify its proposed Reviewing Representative to the Disclosing Party. An attorney or consultant that simultaneously represents market participant(s) and non-market participant(s) may not have access to market sensitive data, subject to the exception in paragraph 3.F. Any designated Reviewing Representative has a duty to disclose to the Disclosing Party any potential conflict that puts him/her in violation of Decision 06-12-030. A resume or curriculum vitae is reasonable disclosure of such potential conflicts, and should be the default evidence provided in most cases.

7. Access to Protected Materials and Use of Protected Materials. Subject to the terms of this Protective Order, Reviewing Representatives shall be entitled to access to Protected Materials. All other parties in this proceeding shall not be granted access to Protected Materials, but shall instead be limited to reviewing redacted versions of documents. Reviewing Representatives may make copies of Protected Materials, but such copies become Protected Materials. Reviewing Representatives may make notes of Protected Materials, which shall be treated as Notes of Protected Materials if they disclose the contents of Protected Materials. Protected Materials obtained by a party in this proceeding may also be requested by that party in a subsequent Commission proceeding, subject to the terms of any protective order governing that subsequent proceeding, without constituting a violation of this order.

8. Maintaining Confidentiality of Protected Materials. Each Reviewing Representative shall treat Protected Materials as confidential in accordance with this Protective Order and the Non-Disclosure Certificate executed pursuant to Paragraph 7 and 8 hereof. Protected Materials shall not be used except as necessary for the conduct of this proceeding, and shall not be disclosed in any manner to any person except (i) Reviewing Representatives who have executed Non-Disclosure Certificates; (ii) Reviewing Representatives' paralegal employees and administrative personnel, such as clerks, secretaries, and word processors, to the extent necessary to assist the Reviewing Representatives, provided that they shall first ensure that such personnel

are familiar with the terms of this Protective Order, and have signed a Non-Disclosure Certificate, (iii) persons employed by or working on behalf of the CEC or other state governmental agencies covered by Paragraph 12. Reviewing Representatives shall adopt suitable measures to maintain the confidentiality of Protected Materials they have obtained pursuant to this Protective Order, and shall treat such Protected Materials in the same manner as they treat their own most highly confidential information. Reviewing Representatives shall be liable for any unauthorized disclosure or use by their paralegal employees or administrative staff. In the event any Reviewing Representative is requested or required by applicable laws or regulations, or in the course of administrative or judicial proceedings (in response to oral questions, interrogatories, requests for information or documents, subpoena, civil investigative demand or similar process) to disclose any of Protected Materials, they shall immediately inform the Disclosing Party of the request, and the Disclosing Party may, at its sole discretion and cost, direct any challenge or defense against the disclosure requirement, and the Reviewing Representative shall cooperate in good faith with such party either to oppose the disclosure of the Protected Materials consistent with applicable law, or to obtain confidential treatment of them by the person or entity who wishes to receive them prior to any such disclosure. If there are multiple requests for substantially similar Protected Materials in the same case or proceeding where a Reviewing Representative has been ordered to produce certain specific Protected Materials, the Reviewing Representative may, upon request for substantially similar materials by another person or entity, respond in a manner consistent with that order to those substantially similar requests.

9. Exception for California Independent System Operator (ISO). Notwithstanding any other provision of this Protective Order, with respect to an ISO Reviewing Representative only, participation in the ISO's operation of the ISO-controlled grid and in its administration of the ISO-administered markets, including, but not limited to, markets for ancillary services, supplemental energy, congestion management, and local area reliability services, shall not be deemed to be a violation of this Protective Order.

10. Non-Disclosure Certificates. A Reviewing Representative shall not inspect, participate in discussions regarding, or otherwise be granted access to, Protected Materials unless and until he or she has first completed and executed a Non-Disclosure Certificate, attached hereto as Appendix A, and delivered the original, signed Non-Disclosure Certificate to the Disclosing Party. The Disclosing Party shall retain the executed Non-Disclosure Certificates pertaining to the Protected Materials it has disclosed and shall promptly provide copies of the Non-Disclosure Certificates to Commission Staff upon request.

11. Return or Destruction of Protected Materials. Protected Materials shall remain available to Reviewing Representatives until the later of the date that an order terminating this proceeding becomes no longer subject to judicial review, or the date that any other Commission proceeding relating to the Protected Material is concluded and no longer subject to judicial review. If requested to do so in writing after that date, the Reviewing Representatives shall, within fifteen days of such request, return the Protected Materials (including Notes of Protected Materials) to the Participant that produced them, or shall destroy the materials, except that copies of filings, official transcripts and exhibits in this proceeding that contain Protected Materials, and Notes of Protected Material may be retained, if they are maintained in accordance with Paragraph 8. Within such time period each Reviewing Representative, if requested to do so, shall also submit to the Disclosing Party an affidavit stating that, to the best of its knowledge, all Protected Materials and all Notes of Protected Materials have been returned or have been destroyed or will be maintained in accordance with Paragraph 8. To the extent Protected Materials are not returned or destroyed, they shall remain subject to the Protective Order and CPUC General Order No. 66-C. In the event that a Reviewing Representative to whom Protected Material are disclosed ceases to be engaged to provide services in this proceeding, then access to such materials by that person shall be terminated. Even if no longer engaged in this proceeding, every such person shall continue to be bound by the provisions of this Protective Order and the Non-Disclosure Certificate.

12. Access and Use by Governmental Entities.

(a) In the event the CPUC receives a request from the CEC for a copy of or access to any party's Protected Materials, the procedure for handling such requests shall be as follows. Not less than five (5) days after delivering written notice to the Disclosing Party of the request, the CPUC shall release such Protected Materials to the CEC upon receipt from the CEC of an Interagency Information Request and Confidentiality Agreement ("Interagency Confidentiality Agreement"). Such Interagency Confidentiality Agreement shall (i) provide that the CEC will treat the requested Protected Materials as confidential in accordance with this Protective Order, (ii) include an explanation of the purpose for the CEC's request, as well as an explanation of how the request relates to furtherance of the CEC's functions, (iii) be signed by a person authorized to bind the CEC contractually, and (iv) expressly state that furnishing of the requested Protected Materials to employees or representatives of the CEC does not, by itself, make such Protected Materials public. In addition, the Interagency Confidentiality Agreement shall include an express acknowledgment of the CPUC's sole authority (subject to judicial review) to make the determination whether the Protected Materials should remain confidential or be disclosed to the public, notwithstanding any provision to the contrary in the statutes or regulations applicable to the CEC.

(b) In the event the CPUC receives a request for a copy of or access to a party's Protected Materials from a state governmental agency other than the CEC that is authorized to enter into a written agreement sufficient to satisfy the requirements for maintaining confidentiality set forth in Government Code Section 6254.5(e), the CPUC may, not less than five (5) days after giving written notice to the Disclosing Party of the request, release such protected material to the requesting governmental agency, upon receiving from the requesting agency an executed Interagency Confidentiality Agreement that contains the same provisions described in Paragraph 12(a) above.

(c) The CEC may use Protected Materials when needed to fulfill its statutory responsibilities or cooperative agreements with the CPUC. Commission confidentiality designations will be maintained by the CEC in making such assessments, and the CEC will not publish any assessment that directly reveals the data or allows the data submitted by an individual load serving entity ("LSE") to be "reverse engineered."

13. Dispute Resolution. All disputes that arise under this Protective Order, including but not limited to alleged violations of this Protective Order and disputes concerning whether materials were properly designated as Protected Materials, shall first meet and confer in an attempt to resolve such disputes. If the meet and confer process is unsuccessful, the involved parties may present the dispute for resolution to the Assigned ALJ or the Law and Motion ALJ.

14 Other Objections to Use or Disclosure. Nothing in this Protective Order shall be construed as limiting the right of a party, the Commission Staff, or a state governmental agency covered by Paragraph 12 from objecting to the use or disclosure of Protected Material on any legal ground, such as relevance or privilege.

15. Remedies. Any violation of this Protective Order shall constitute a violation of an order of the CPUC. Notwithstanding the foregoing, the parties and Commission Staff reserve their rights to pursue any legal or equitable remedies that may be available in the event of an actual or anticipated disclosure of Protected Materials.

16. Withdrawal of Designation. A Disclosing Party may agree at any time to remove the "Protected Materials" designation from any materials of such party if, in its opinion, confidentiality protection is no longer required. In such a case, the Disclosing Party will notify all other parties that the Disclosing Party believes are in possession of such materials of the change of designation.

17. Interpretation. Titles are for convenience only and may not be used to restrict the scope of this Protective Order.

Entered: ______________________________
Administrative Law Judge

Date: ______________________________

APPENDIX A TO PROTECTIVE ORDER

BEFORE THE PUBLIC UTILITIES COMMISSION

OF THE STATE OF CALIFORNIA

Submission of Contracts for Procurement of Renewable Energy Resulting From Renewables Standard Contracts Program	)))))	**Advice 2547-E**

NON-DISCLOSURE CERTIFICATE

I hereby certify my understanding that access to Protected Materials is provided to me pursuant to the terms and restrictions of the Protective Order in this proceeding, that I have been given a copy of and have read the Protective Order, and that I agree to be bound by it. I understand that the contents of the Protected Materials, any notes or other memoranda, or any other form of information that copies or discloses Protected Materials shall not be disclosed to anyone other than in accordance with that Protective Order. I acknowledge that a violation of this certificate constitutes a violation of an order of California Public Utilities Commission.

By: ______________________________
Title: ___________________________ _
Representing: _____________________
Date: ___________________________ _

SOUTHERN CALIFORNIA
EDISON
An *EDISON INTERNATIONAL* Company

James W. Yee
Supervisor of Advice Letters
James.Yee@sce.com

February 2, 2011

California Public Utilities Commission
505 Van Ness Avenue, 4th Floor
San Francisco, CA 94102

Attn: Honesto Gatchalian
Energy Division

Re: Substitute Sheets for Southern California Edison Company's Advice 2547-E

Dear Mr. Gatchalian:

Enclosed are an original and three copies of substitute sheets for SCE Advice 2547-E filed on January 31, 2011 entitled, Submission of Contracts for Procurement of Renewable Energy Resulting from Renewables Standard Contracts Program. Appendix DD-Proposed Protective Order is being replaced to include the advice letter number in the captions of the document.

Please include these additional sheets in your master file for Advice 2547-E and distribute the copies to the appropriate people reviewing Advice 2547-E

Should you have any questions, please contact me at (626) 302-2509.

Sincerely,

James W. Yee

JWY:jm
Enclosures

cc: Don Lafrenz, Energy Division
Parties on SCE's GO 96-B service list
Parties in R.06-02-012 and R.08-08-009 service lists.

EXHIBIT G

Docket No. 07-AFC-6

CENTER FOR BIOLOGICAL DIVERSITY'S RESPONSE IN SUPPORT OF CITY OF CARLSBAD'S MOTION TO TAKE OFFICIAL NOTICE AND THE CENTER'S MOTION TO TAKE OFFICIAL NOTICE AND RE-OPEN THE EVIDENTIARY RECORD

San Diego County Air Pollution Control District Comments on the Air Resources Board May 19, 2010, Public Meeting on Revising the Compressed Natural Gas Fuel Specifications for Motor Vehicles

I. GENERAL COMMENTS

The San Diego County Air Pollution Control District (District) acknowledges and supports changes to the compressed natural gas (CNG) fuel specifications needed to address local issues within California that may hinder the use of natural-gas-fueled vehicles (NGVs). However, any change to the compressed natural gas (CNG) fuel specifications must be done in such a way that it preserves the current and anticipated future emission reductions from NGVs and does not indirectly result in increased emissions from other sources. As discussed below, the District believes that, unless carefully crafted, any change to the existing regulations will remove an existing barrier to the importation of natural gas derived from liquefied natural gas (LNG) into San Diego and result in significant emission increases from this higher emitting natural gas fuel.

The District supports natural gas vehicle (NGV) use and wishes to encourage growth of these innately low-emitting vehicles. In addition, the District supports alternative supplies of natural gas for San Diego. However, the fuel that NGVs use and any alternative natural gas supplies must not result in significant excess emissions when compared to the current natural gas supply in order to avoid backsliding on hard-won emission reductions that have been achieved through District rules and ARB regulations. The growth of the NGV vehicle sector, which is purported to be the main purpose behind a change to the current fuel specification, cannot be allowed to occur if it will indirectly result in an increase in emissions from stationary sources and/or transmission emission leaks. Therefore, all direct and indirect emission increases from the facilitated importation of LNG-derived natural gas resulting from changes to the CNG fuel specifications must either be reduced to insignificance by treating the LNG-derived natural gas, or fully mitigated by other emission reductions so that the environmental benefits from use of NGVs and natural gas combustion in general are not merely offset by emission increases from other sources. Otherwise, the expeditious attainment of federal and state ambient air quality standards in San Diego and throughout California will be jeopardized.

II. USE OF IMPORTED LNG-DERIVED NATURAL GAS

The District's overarching concern with revising the CNG fuel specifications is that any revision must not indirectly result in unmitigated, significant emission increases of volatile organic compounds (VOCs), oxides of nitrogen (NOx), and other pollutants by removing a barrier to the importation of LNG-derived natural gas. The District has no issue with the use of imported LNG-derived natural gas provided that any resulting emission increases relative to the current natural gas supply from all sources are prevented or fully mitigated.

As noted in ARB's meeting presentation, imported LNG-derived natural gas has significantly higher content of hydrocarbons other than methane (ethane, propane, butane, and pentane) than the imported pipeline gas that provides most of the natural gas supply in California, including the existing San Diego gas supply. It also has little or no inert content compared to existing supplies. Also as noted in ARB's meeting presentation, the effect of this composition change is to increase the Wobbe Index (WI) and decrease the Methane No. (MN), relative to the existing pipeline natural gas. In addition, the weight fraction of individual C2+ hydrocarbons (ethane, propane, butane, and pentane) may be increased as well as the weight fraction of VOCs (propane and higher hydrocarbons, or C3+).

As a result of these compositional differences from the typical interstate supplied natural gas currently used in California, significant increases in emissions may result directly from NGVs subject to the regulation, as well as indirectly from stationary combustion sources, since all sources are served by a common gas transmission and distribution system. Moreover, fugitive VOC leakage from the natural gas transmission and distribution system itself will be greatly increased. If the CNG fuel specifications are changed in a manner that encourages the use of LNG-derived natural gas—such as a statewide performance standard based on the WI and MN with no other restrictions on CNG composition—any resulting emission increases from the associated use of LNG-derived natural gas from NGVs and other indirectly affected sources must be fully analyzed and mitigated.

A. PROSPECTS FOR USE OF LNG-DERIVED NATURAL GAS

The importation of LNG-derived natural gas is not a theoretical concern since LNG infrastructure is already in place. Sempra LNG, a wholly owned subsidiary of Sempra Energy, owns the Energia Costa Azul (ECA) LNG terminal in Baja California Norte, Mexico, near Ensenada, Mexico. The ECA terminal is operational and directly connects to the San Diego Gas & Electric (SDG&E) gas transmission system at the Otay Mesa Border by means of the Transportadora de Gas Natural de Baja California (TGN) pipeline in Mexico which in turn connects to the Gasoducto Bajanorte (GB) LNG spur pipeline from the facility. SDG&E, TGN, and GB are wholly owned subsidiaries of Sempra Energy.

The LNG-derived natural gas entering San Diego through Otay Mesa would not be diluted by any other gas supply and would essentially reach San Diego with its composition unaltered. The LNG-derived natural gas can also indirectly reach San Diego—and the rest of Southern California—by being transported east on the GB pipeline in Mexico which connects to the North Baja Pipeline near Ogilby, California, which in turn connects to the Southern California Gas Company (SoCal Gas) system at Blythe, California, and also the El Paso pipeline at nearby Ehrenberg, Arizona. SoCal Gas, also a wholly owned subsidiary of Sempra Energy, currently receives westward flowing natural gas from the El Paso Pipeline at Ehrenberg. The El Paso Pipeline receipt point represents about 30% of the firm capacity of the SoCal Gas system, and directly serves southern portions of the South Coast Air Quality Management District (SCAQMD), all of Imperial County, and most of San Diego through Ehrenberg and Blythe. LNG-derived natural gas entering California by this route could be diluted to some extent by the flow of gas from the east on the El Paso Pipeline.

B. IMPACT OF IMPORTED LNG-DERIVED NATURAL GAS ON SOUTHERN CALIFORNIA NATURAL GAS SUPPLIES

The ECA terminal has a normal baseload LNG-derived natural gas send-out capacity of 1000 million standard cubic feet per day (MMscfd) with a peak capacity of 1300 MMscfd based on published reports. The maximum gas usage in Baja Norte California is about 300 MMscfd leaving up to 1000 MMscfd available for export to San Diego and the rest of Southern California.

The maximum firm capacity at Otay Mesa to supply gas into the combined SDG&E and Southern California Gas Company (SoCal Gas) system is about 400 MMscfd on a minimum consumption day (the physical capacity is higher when more gas is consumed). The average natural gas consumption in San Diego was about 330 MMscfd in 2008. It is obvious that there is sufficient capacity to deliver enough LNG-derived natural gas to the Otay Mesa receipt point to saturate nearly all of San Diego with LNG-derived natural gas. This was confirmed during the facility's shakedown in May, 2008, when LNG-derived natural gas reached most of the heavily populated area of San Diego. Since the firm capacity of the North Baja and GB pipelines is about 600 MMscfd, flows of LNG-derived natural gas by this route would represent about 50% of the firm capacity of the SoCal Gas transmission system from Blythe (1210 MMscfd) which serves Imperial County and the southern portion of the SCAQMD.

Moreover, all the permits are in place, according to Sempra LNG, to expand the ECA terminal and the corresponding GB pipeline in Mexico to a peak capacity of 2600 MMscfd. The foundations for two more LNG storage tanks, in addition to the two already operational, have already been laid. In addition, the Federal Energy Regulatory Commission (FERC) has approved an expansion of the North Baja pipeline to enable it to transport approximately 2700 MMscfd of LNG-derived natural gas. This could be done in a matter of a few months. When the ECA terminal is expanded, the southern portion of the SoCal Gas system would likely be receiving nearly 100% LNG-derived natural gas since the maximum firm capacity of pipeline from Blythe westward is only about 1200 MMscfd.

C. IMPACT OF CHANGES TO THE CNG FUEL SPECIFICATIONS ON IMPORTATION OF LNG-DERIVED NATURAL GAS

At this time, one half the ECA terminal is leased by Sempra LNG to a Royal Dutch Shell (Shell) subsidiary (which has assigned a portion of its rights to Gazprom Global LNG) and the other half is owned and operated by Sempra LNG. However, this arrangement could be changed if it was profitable for Sempra LNG to use the rest of the terminal. The ECA terminal can receive LNG cargoes from anywhere in the world and is currently fully operational although only the Sempra LNG half of the terminal is currently active at about 50% of capacity (i.e., 25% of the full terminal capacity). Market forces could make the entire terminal active at 100% capacity in a matter of weeks.

One such market force would be the establishment of customers for LNG-derived natural gas in San Diego or elsewhere in Southern California. Sempra LNG has ready customers for that gas in SDG&E, which sells a large majority of the natural gas in San Diego, and SoCal Gas. Although the price for natural gas is higher in Asia than the California market, Sempra LNG has stated that it is profitable for them to import LNG through the ECA terminal. This is because the price Sempra LNG pays for its LNG is a price based on the Southern California Border Index price for natural gas rather than the higher price in Asian markets, which is often indexed to the price of oil.

The current CNG fuel specifications represent the final regulatory barrier to widespread importation of LNG into Southern California. Although LNG-derived natural gas does comply, or can be made to comply by nitrogen injection to lower the WI, with the California Public Utilities Commission (CPUC) standards for pipeline natural gas , it does not in general comply with the existing CNG fuel specifications.

SDG&E and SoCal Gas assert that LNG will be imported into the system regardless of the CNG fuel specification. However, in reality if imported LNG-derived natural gas is imported into the SDG&E system, SDG&E would have to discontinue sales of natural gas to CNG vehicle owners since they are served by the same gas transmission system as all other customers. This would result in the loss of revenue from the CNG customers for SDG&E and its parent company—Sempra Energy. SDG&E (and SoCal Gas) would also have to forego the revenue from the expected large expansion of this market in the future. This barrier would be removed by a statewide performance standard based solely on the WI and MN as proposed by SDG&E and the SoCal Gas. This is one reason, Sempra, SDG&E, and SoCal Gas have repeatedly sought to have the CNG fuel specifications amended since at least 2005.

III. IMPORTED LNG-DERIVED NATURAL GAS AND EMISSIONS

A. LNG COMPOSITION VARIABILITY

As noted above and in ARB's presentation, the composition of LNG-derived natural gas differs from the historical baseline gas by increases in ethane, propane, and/or butane and a decrease in inert species (nitrogen and carbon dioxide). Also as noted in ARB's meeting presentation, the composition of LNG-derived gas varies widely depending on the LNG source. The major sources of LNG are expected to be Tangguh, Indonesia, for Sempra LNG and Sakhalin Island, Russia, for Shell and Gazprom Global LNG. However, other LNG marketers could provide shipments from a large variety of sources. For example, the open season bidding held by North Baja Pipeline in conjunction with GB for the proposed expansion of the North Baja pipeline resulted in five companies signing precedence contracts for delivery of LNG-derived natural gas from the ECA terminal through the North Baja pipeline to the SoCal Gas system. The listed sources of the LNG included Sakhalin Island, Tangguh, and Australia (one company declined to indicate a source). In addition, companies could elect to purchase LNG on the spot market to fulfill their contracts. For example, up to one half of Sempra's Tangguh supply can be diverted by Tangguh PSC Contractors, the supplier, if it is more profitable. LNG purchased on the spot market could come from anywhere in the Pacific basin or potentially even from the Middle East.

Therefore, it is reasonable to estimate potential emission impacts, especially daily impacts, based on an expected worst-case LNG composition from the Middle East or the Pacific Basin. The District currently believes LNG from Malaysia, which is currently one of the largest LNG suppliers in the Pacific Basin, likely represents a worst-case LNG for estimating emission increases. The District notes that there is little public information currently available on LNG compositions, especially the composition upon arrival at ECA (LNG can become enriched in C2+ during transit since those hydrocarbons have higher boiling points than methane).

Since the importation of LNG will be driven by the volatile price of natural gas, the composition of natural gas experienced by users of SDG&E and SoCal Gas could rapidly change in a matter of days, including a return to interstate supplied natural gas. This is in contrast to the current situation where gas composition has remained relatively stable over time. This is of particular concern to facilities with permitted equipment because the equipment must be tuned to maintain compliance with permit limits for NOx and/or VOCs. It is also of major concern to the District due to the uncertainty this creates in predicting district-wide emissions, and due to the potential for increased non-compliance from sources regulated by the District.

B. EFFECTS OF IMPORTED LNG-DERIVED NATURAL GAS COMPOSITION ON NOX AND VOC EMISSIONS

A performance based standard based on the WI and MN does not serve to fully characterize NOx or VOC emission increases from LNG-derived natural gas. The upper limit on the WI and the lower limit on the MN may serve to characterize maximum NOx emissions from some engines, for example NGV engines. However, the District expects that neither the WI nor MN would be sufficient to fully characterize NOx emissions from many stationary source combustion devices. For VOC emissions from combustion devices, it appears that a reasonable parameter to correlate VOC emissions is the weight fraction (or weight percent) of C2+ hydrocarbons based on the SwRI engine testing. Finally, fugitive emissions from the gas transmission and distribution system are expected to be directly proportional to the weight fraction of VOCs in the natural gas.

Since the WI and MN are both functions of the hydrocarbon composition, it is possible that either one or both of these parameters may indirectly define maximum potential emissions. However, they can not be used to define the NOx or VOC emission potential of any particular natural gas. The relation of emissions to gas composition is more fully discussed below.

1. NGV Engines

NOx Emissions. The SwRI heavy-duty (HD) engine testing (Please see also comments on ARB Slide Nos. 27 and 48) has demonstrated that existing lean-burn engines used in NGVs exhibit increases in NOx when using natural gas with higher C2+ than existing interstate pipeline gas supplies such as would be the case with LNG-derived natural gas. The District notes no gas used during this testing was representative of the existing interstate pipeline gas used in San Diego in all respects. The gas most closely representative did represent the existing WI in San Diego fairly well but had about twice the C3+ (on a volume basis) as the existing gas supply.

The District has examined the emission increases for NOx and finds they can be relatively well-correlated based on WI and/or MN with emissions increasing for higher WI and lower MN. For most engines tested, the emission increases correlates most strongly with the MN. The rich burn engine tested, which was equipped with a three-way catalyst (TWC) to control NOx and VOC emissions, does not show any significant NOx emission increase relative to a baseline gas across the range of gases tested. However, since the testing was confined to a new engine it is not clear if this will remain true as the engine and associated control system ages. A test of a stationary rich-burn engine sponsored by SoCal Gas with a TWC catalyst showed significant emission increases with increased WI.

VOC Emissions. Based on an examination of the VOC emissions in the SwRI testing, the ratio of VOC emissions to total organic gas (TOG) emissions correlate well with the weight fraction of ethane and propane in the fuel, with propane having the strongest effect. TOG in turn is correlated with the WI and/or MN, decreasing with increasing WI or decreasing MN. However, the proportional changes in TOG emissions are relatively small (10-35%) compared to the potentially large increases in weight fraction of C2+ hydrocarbons possible (a factor of more than 7 for VOCs) for reasonable worst-case LNG-derived natural gas compositions.

2. Stationary Combustion Equipment

NOx Emissions. Stationary combustion equipment can be tuned to operate well over a wide range of gas compositions. However, evidence shows that some important combustion equipment, when tuned to operate on a gas with a certain WI, has significantly increased NOx emissions with increases in the WI above the tuning WI. These impacts will be largest for devices that do not monitor and control the oxygen content of exhaust (i.e., boilers without O_2 trim systems) or control fuel flow to achieve a set output of energy. This is likely to be the case for much of the unpermitted commercial and industrial combustion equipment in San Diego.

In addition to WI effects, there is extensive experimental data that supports increases in NOx emissions not related to the WI. For example, an increase in propane content may cause a NOx emission increase even if the WI is unchanged. The District preliminarily estimates that this effect is on the order of a few percent increase in NOx for most commercial and industrial equipment without add-on NOx emission control devices for the range of LNG-derived gas compositions expected (equipment with add-on NOx emission controls have so far not shown NOx emission sensitivity to natural gas composition changes). The effect is important because it means NOx emission estimates can not be based solely on the WI.

VOC Emissions. By analogy with the SwRI HD engine test results, the District expects that these emissions are characterized by the weight fraction of C2+ in the fuel. The analogy is especially relevant for San Diego because about 50% of the estimated VOC emission increase from stationary source combustion comes from lean-burn engines.

3. Fugitive VOC Emissions from Gas Transmission and Distribution

Although the natural gas composition may influence the fugitive leak rate (through changes in viscosity and density, for example) the District expects that the most important parameter to characterize VOC emissions is the weight fraction of VOC in natural gas. This can vary by a factor of more than seven over the range of expected LNG-derived natural gas compositions.

C. POTENTIAL EMISSION IMPACTS FROM LNG-DERIVED NATURAL GAS

Although more research is needed to fully quantify the magnitude of VOC and NOx emission increases, the District has concluded there are significantly increased emissions of both VOCs and NOx in San Diego from the use of LNG-derived natural gas from the following sources:

- NGVs
- Stationary combustion sources
- Natural gas transmission and distribution system (VOCs only)

The preliminary District estimates of emission increases in tons per day (tpd) from these emission sources are shown in Table 1. The estimates reflect emission increases that would potentially occur if the current CNG fuel specifications are replaced with a performance based standard (based on a maximum WI of 1385 and minimum MN of 80 as proposed by SDG&E and SoCal Gas) thereby resulting in the reasonably foreseeable use of LNG-derived natural gas throughout San Diego County. The emission estimates assume a likely worst-case LNG-derived natural gas composition (Malaysian) and, consistent with recent legal decisions under CEQA, are evaluated relative to the actual existing baseline gas composition. The emission estimates are preliminary and may be refined based on additional test results and stakeholder comments. However, the District considers them sufficiently accurate to demonstrate a significant emission increase in San Diego from such a regulatory change.

Preliminary Estimated NOx and VOC Emission Increases in San Diego from LNG-Derived Natural Gas

Category	NOx, tpd	VOC, tpd
Gas Transmission & Distribution	0	>5
Stationary Combustion Sources		
District Inventoried Combustion Sources	0.12	0.27
Residential Appliances	0.07	0.05
Unpermitted Commercial & Industrial Equipment	0.35	0.03
NGVs		
Transit & School Busses, 2010	0.13	0.06
Transit & School Busses, Future	≈ 0	0.14
Total, 2010	0.67	5.41

The large increase in VOC emissions from gas transmission and distribution (and VOC emissions in general) is due to the large difference in the weight percent VOC between the baseline gas (about 1.4%) and LNG-derived gas that was evaluated (about 11%). LNG-derived natural gas from sources with lower weight percent VOC would have corresponding lower, although still significant, emission increases. For example, the preliminary estimated emission increase from gas transmission and distribution for Tangguh LNG-derived natural gas is about 0.45 tons per day.

It should be noted that emission estimates for stationary permitted and unpermitted combustion sources reflect the expected populations of types of combustion devices in San Diego County and may not be applicable to other air districts. In particular, it is expected that most of the unpermitted commercial and industrial equipment in San Diego is relatively high NOx emitting devices using conventional, nonpremixed combustion equipment.

D. SIGNIFICANCE OF EMISSION IMPACTS

One of the District's primary goals is to attain the health protective state and federal ambient air quality standards. The District currently attains all the standards except for state and federal ozone standards and state particulate matter standards. In this context, the significance of these projected emission impacts cannot be overestimated. By way of comparison, the District would consider a rule change reducing emissions by 0.1 ton per day of VOCs and NOx, which are ozone precursors, to be significant. But most concerning is the fact that the projected emission increases from the importation of LNG-derived natural gas would effectively nullify **all** of the VOC reductions, and more than half of the district-wide NOx average daily reductions projected to occur from the feasible control measures committed to as part of the District's 2009 Regional Air Quality Strategy to attain the state ambient air quality standards for ozone.

Furthermore, in 2009, the District would have complied with the 1997 federal 8-hour ozone standard except for one day with a 0.0850 ppm ozone level. Had the ozone level been 0.0849 for the 8-hour period, a difference of about 0.1%, the District would have complied with the standard. Thus, the projected emissions increases from LNG-derived natural gas may significantly affect the District's ability to attain and maintain attainment of air quality standards.

E. OTHER EMISSION IMPACTS

1. Particulate Matter

Relatively little testing has been done to quantify changes in particulate emissions from changes in fuel gas composition. The testing the District is aware of on premixed combustion devices (where the fuel and air are completely or partially premixed prior to combustion) has shown no consistent trend in particulate emissions with increasing C2+ in the fuel. However, recent tests on a nonpremixed lean-burn engine did show a significant increase in particulate emissions with increased C2+. This is likely because nonpremixed combustion devices can have regions of combustion with rich fuel to air ratios conducive to particulate matter formation. A reasonable expectation is that other nonpremixed combustion devices will show a similar trend. Therefore, potential emission increases of particulate matter from this type of equipment should be analyzed and its significance determined. More research, including testing, may be necessary to better establish the magnitude of the impact.

2. Toxic Emissions

Similarly to particulate matter, relatively little testing has been done to quantify changes in toxic emissions from changes in fuel gas composition. Testing that the District is aware of on premixed combustion devices has shown no consistent trend in toxic emissions with increasing C2+ in the fuel. However, emissions of toxic compounds such as benzene and polycyclic aromatic compounds (PAHs) would be expected to increase in concert with particulate matter. A reasonable expectation is that nonpremixed combustion devices would show an increase in these compounds based on the very limited testing for these devices. Therefore, potential emission increases of toxic air contaminants from this type of equipment should be analyzed and its significance determined. More research, including testing, may be necessary to better establish the magnitude of the impact.

3. NO_2 Emissions

There is experimental evidence that C2+ hydrocarbons are much more efficient than methane in converting nitric oxide, NO, to nitrogen dioxide, NO_2, under conditions typical of the exhaust from gas turbines. There is also at least one documented case where a "brown cloud" that is characteristic of elevated NO_2 emissions was observed from a turbine operating in Asia on LNG-derived natural gas. The cloud was attributed to the higher C2+ in the fuel compared to an identical North American turbine where no cloud was observed. This affect is only likely during low-load operation of turbines under conditions where add-on emission controls are not effective such as during startups and commissioning. Nevertheless, it may have important implications on the ability of turbine operators to be able to demonstrate they will not cause a violation of the ambient air quality standards for NO_2. The potential significance of this impact needs to be analyzed.

IV. COMMENTS ON SPECIFID ARB PRESENTATION SLIDES

A. Slide 7

The statement that a portion of potential LNG supplies do not meet the standard is literally correct but does not emphasize that nearly all likely LNG supplies would not meet the existing ARB standard when inert gas content is considered. Unless inert gasses are added to the LNG after it is revaporized, virtually no LNG-derived natural gas will have inert gasses more than 1.5%, the minimum allowed by current CNG fuel specifications.

B. Slide 15

The District agrees that addressing associated gas that does not currently meet the current CNG fuel specification is important. The District recommends that this be done in manner that restricts the applicability of the change to the affected local area and that does not remove the existing barriers to use of LNG-derived natural gas in the state—unless the significant impacts from use of LNG-derived natural gas are fully mitigated.

C. Slide 25

The NGV market is not restricted by limited access to LNG-derived natural gas. There is currently no shortage of natural gas in California.

D. Slide 27

The results from the Southwest Research Institute (SwRI) final report "Fuel Composition Testing Using DDC Series 50G Natural Gas Engines," Michael Feist, prepared for the Southern California Gas Company, August 2006, should also be considered in any estimates of emission increases from changes to the CNG fuel specification. One of the engines tested, was retested in the SwRI HD engine study in 2009. For this engine, the NOx emission increase and emissions for the CARB certification fuel were significantly higher in the 2009 testing than in the 2006 testing for unexplained reasons. SwRI considers both the 2006 and 2009 test results as being equally valid for that engine. In addition, the other engine tested is likely still a significant part of the existing fleet in other air districts.

E. SLIDE 31

The legend for this graph provided by SoCal Gas does not indicate any Detroit Diesel TK or MK engines currently in service. Based on recent survey information, the District estimates about 7% of the existing San Diego natural gas-fueled transit bus fleet is powered by the TK engine (33 busses). The TK and MK engines may form an even higher proportion of NGV engines in other districts. To the District's knowledge, the GK engine has not been tested for its response to changes in natural gas quality, such as from LNG-derived natural gas, while the TK and MK engines have been tested.

F. SLIDES 43 AND 44

The appropriate baseline to use in estimating emission increases is not the worst possible composition (e.g., the lowest MN and highest WI) under the existing regulation. Rather it is the existing baseline natural gas composition in the area affected by the change in regulations. For San Diego, this is the composition of the imported pipeline gas passing through Ehrenberg on the El Paso Pipeline (see ARB Slide 14) with a WI, MN, and VOC content of about 1335, 100, and 0.5% by volume, respectively.

In addition, for NGV emissions, VOC emissions require consideration of the mass fraction of ethane and VOCs in the fuel hydrocarbons in addition to the MN and WI. Based on the SwRI HD Engine Study, propane, and presumably other VOCs, has a stronger affect on VOC emissions than ethane since ethane itself is not a hydrocarbon and can only significantly contribute to VOC emission increases through ethene, an intermediate product of ethane combustion. In this regard, the amount of VOCs in the fuel will have an even stronger effect on emissions of VOCs from rich-burn engines with TWCs than on lean-burn engines. Based on the SwRI testing, very little ethene or propene is present in the engine exhaust from rich-burn engines (downstream of the TWC) relative to the ethane and propane. This is probably because the TWC selectively removes the more reactive ethene and propene. Thus, ethane does not contribute significantly to VOC emissions from such engines.

G. SLIDE 45

Since the SwRI HD engine testing involved primarily new engines, any analysis of the emission impacts must also take into account the potential for emission increases with engine use from deterioration of the engine and add-on emission control systems (TWCs and oxidation catalysts). This is especially the case for rich-burn HD and light-duty (LD) natural-gas-fueled engines since emissions from gasoline-fueled LD vehicles, which use the same emission control technology (TWC), are known to have significant emission increases over time under real-world operation and maintenance conditions. In addition, unlike LD gasoline-fueled vehicles, NGVs are not subject to mandatory smog testing to evaluate their emission status. The actual emission increase of the operational fleet must be analyzed to properly assess the emission impacts.

In this regard, the District preliminarily concludes that, based on an evaluation of the SwRI heavy-duty (HD) engine testing and considering impacts of engine emission increases with use, the magnitude of the VOCs will not decrease to insignificance over time as rich-burn engines replace the existing lean-burn engines in the transit bus fleet (the major source of NGV emissions in San Diego). The District notes that the rich-burn engine tested was new, required extensive repairs before testing—even though it was new, and relies on a TWC to achieve its low NOx and VOC emissions. The District's analysis did not consider the potential expansion of the NGV fleet or light-duty NGV emissions.

H. SLIDE 49

Test fuels for the SwRI LD engine test sponsored by SoCal Gas do not represent typical natural gas fuel compositions actually used in most of California. The highest MN for the fuels was about 89 while the lowest propane content was about 2% by volume. As indicated on ARB Slide 9, 87% of the gas supply is from imported interstate pipeline gas that has a MN of 95–100 and a VOC content of about 0.5% by volume. It is questionable if the natural gas compositions used in the test allow adequate baseline emission factors to be established.

I. SLIDE 54

Since emissions in the Sierra Research study are evaluated relative to CARB certification fuel rather than existing imported interstate pipeline gas used by most NGVs, the emission increases (or decreases) in this slide are not representative of the emission increases in most of California.

In addition, the nonmethane hydrocarbons (NMHC) increases indicated may underestimate the VOC emission increases. Test gases 2 and 3 in the SwRI LD vehicle study have increased propane but reduced ethane compared to the ARB certification gas. Based on the District's analysis of the SwRI HD engine study data for the one rich-burn engine tested, the expected increase in VOCs would be greater than the expected increase in NMHC because the smaller ethane (a NMHC but not a VOC) concentration in the fuel reduces the emission increase in NMHCs and masks the potential increase in VOCs. Ethane does not contribute significantly to the VOC emission increase from rich burn engines (Please see also comments on ARB Slides 43 and 44).

J. SLIDE 65

A change in regulations that enables the use of imported LNG will not significantly improve the availability or natural gas fuel meeting ARB specifications nor improve the NGV market in San Diego. San Diego does not directly receive any associated gas production. Approximately 95% of San Diego's gas supply is directly from imported interstate pipeline gas that has historically been compliant with the existing standards.

Based on monthly average gas compositions provided by SoCal Gas, there appear to be a few instances when gas supply from the coastal line, which does indirectly receive some California producer gas that is extensively blended with other supplies, had an inert content slightly below the existing CNG specifications. However, this line only carries about 5% of the natural gas supply in San Diego and only serves a small north coastal area of San Diego. The District recommends that any changes to the regulation to address this issue be limited to the affected area and limit the reduction in inert content to the amount needed to allow consistent compliance for the gas in the affected area.

K. SLIDE 74

The District has no objection to adopting a performance standard as long as it does not allow the importation of LNG-derived natural gas that significantly increases pollutant emissions—both from NGVs and stationary combustion sources and the gas transmission system—unless those emission increases are fully mitigated. Unless the emission increases are mitigated, emission benefits from the increased use of NGVs are likely to be dwarfed by increases in emissions from other sources if the regulatory changes enable imported LNG-derived natural gas to be used in San Diego.

V. COMMENTS ON SOCAL GAS/SDG&E PROPOSAL TO REVISE CARB MOTOR VEHICLE FUEL REGULATIONS

A. PAGE 2 BULLET NO. 3

Although it is still investigating the issue, the District has found little evidence that interstate sourced natural gas in San Diego County is below the minimum inert limit for CNG fuel.

B. PAGE 4 BULLET NO. 2

This bullet implies that interstate natural gas supplies almost never meet ARB fuel specification, when, in fact, most interstate supplies almost always meet the specifications.

C. PAGE 5 BULLET NO. 3

Any streamlined exemption process should provide opportunity for District participation in the process.

D. PAGE 6 BULLET NO. 1

Adoption of statewide performance based standards, as proposed by SoCal Gas and SDG&E, would result in importation of LNG-derived natural gas into San Diego County with significant emission increases of VOCs and NOx. The emission impacts must be mitigated to insignificance or they will interfere with San Diego County attaining the state and federal ambient air quality standards. The LNG-derived gas would also be imported into Imperial County and the SCAQMD.

E. PAGE 7 BULLET NO. 1

The SwRI LD vehicle testing indicates that NMHCs, which include VOCs, increased significantly when the MN decreased from 89 to 75. The WI for these tests was within the range allowed by the CPUC standards. The VOC emission increase is likely even greater than that indicated by the NMHC increase. Therefore, there are emission increases from light-duty vehicles associated with using natural gas allowed under the CPUC standards that deviates significantly from the typical existing supplies.

F. PAGE 9 BULLET NO. 3 AND PAGE 10 BULLET NO. 1

The District disagrees with the statements that there will be no impact on stationary sources emissions and no impact on mobile source emissions. The District also disagrees with the statements that adopting a statewide performance based standard will not result in an increase in the use of imported LNG-derived natural gas. Please see District comments above.

VI. RESIDENTIAL APPLIANCE SAFETY

Although appliance safety is outside the District's regulatory scope, public safety issues are another indirect impact that must be analyzed as part of this process. In particular, the safety of residential appliances when operating on LNG-derived natural gas needs to be confirmed to fully assess the impacts from any regulatory change that encourages the use of such natural gas.

Recent testing by the Air Conditioning Heating and Refrigeration Institute (AHRI), which includes natural gas appliance manufacturers, raises concerns that appliance safety may be jeopardized by using LNG-derived natural gas. The safety issues (high CO emissions) mostly occurred when an appliance tuned on a baseline gas was operated on a gas with a 4.4% higher WI and then challenged with over firing. The purpose of the over-firing challenge is to address: barometric pressure changes, altitude variations, manufacturing tolerances, installation tolerances, reasonable misapplication and misinstallation, aging of the appliance, and WI changes. The other factors are viewed as least as important as WI changes.

In response to some comments at the workshop, the District contacted the AHRI. According to an AHRI representative:

- No safety devices were rendered inoperative during the testing.
- The testing was conducted at rated input, which, in some cases, resulted in returning under-rated appliances to their specified rating. This is the same procedure as the national testing labs use throughout the world because there is no way to make sure the manufacturer always uses the same under-rated condition.

- The test procedures are periodically evaluated to determine their continued applicability to assessing appliance safety. The over-fire test is close to 90 years old but is still applicable to today's technology.

EXHIBIT H

Docket No. 07-AFC-6

CENTER FOR BIOLOGICAL DIVERSITY'S RESPONSE IN SUPPORT OF CITY OF CARLSBAD'S MOTION TO TAKE OFFICIAL NOTICE AND THE CENTER'S MOTION TO TAKE OFFICIAL NOTICE AND RE-OPEN THE EVIDENTIARY RECORD

West Coast LNG Projects and Proposals
Status Update (12/7/10)

Note: Changes since last update are in **bold**.

Project Name, Company and Location	Average Production Capacity (Bcfd)*	Status
California		
Port Esperanza Esperanza Energy LLC Offshore California	1.2 Peak	Project feasibility study announced on March 4, 2006. 3/7/07 - Esperanza Energy, LLC announced plans to file applications with state and federal agencies to build a floating LNG receiving facility. This project is currently on hold with no date given for application submittal.
Oregon		
Port Westward LNG Facility Port Westward LNG LLC Clatskanie, Oregon	0.7 1.25 Peak	3/10/06 - The Port of St. Helens has approved a 99-year lease agreement on land along the Columbia River. Delays in obtaining a lease had caused at least one major investor in February to withdraw from the project. Port officials expect the Thompson family, who own the land, to approve the agreement soon. The project still needs permits and financing, though officials state that there have been "serious inquiries" from financial backers since the port approved the lease agreement.
Oregon LNG Funding Partners Astoria, Oregon	1.0 1.5 Peak	6/11/08 – Oregon LNG has issued its Water Suitability Assessment (WSA) to the U.S. Coast Guard. 10/10/08 – Oregon LNG files formal application with FERC. 4/21/09 – The U.S. Coast Guard issues a letter of recommendation for Oregon LNG. 6/8/09 – Oregon LNG signs MOU with the State of Oregon on CO2 mitigation, plant retirement and emergency preparedness. 11/18/09 – A federal magistrate rules that Astoria's Port should extend both its sublease with Oregon LNG and the Department of State Lands for three decades. 3/23/10 – Port of Astoria commissioners voted to renew a land lease with Oregon LNG. **5/14/10 – U.S. FERC asks Oregon LNG to schedule pipeline open season soon or withdraw the application for its authorization. Oregon LNG was the only respondent to the open season.**

West Coast LNG Projects and Proposals
Status Update (12/7/10)

Note: Changes since last update are in **bold**.

Project Name, Company and Location	Average Production Capacity (Bcfd)*	Status
Jordan Cove Energy Project Fort Chicago Energy Partners L.P. Coos Bay, Oregon	1.0	11/07/07 – The Coos County Board of Commissioners voted to unanimously approve Jordon Cove Energy Project's application for an Administrative Conditional Use (ACU) permit. 6/30/08 – The U.S. Coast Guard issues Water Suitability Assessment (WSA) Report; sites that significant changes are needed for project. 8/29/08 – FERC issues the Draft EIS, finds the project environmentally acceptable. 5/1/09 – FERC issues the Final EIS, finds the project environmentally acceptable. 12/17/09 – FERC approves Jordove Cove, Oregon Governor to appeal. 1/19/10 – The state of Oregon has petitioned FERC to rehear the case on Jordon Cove. 9/1/10 – PacificConnector Gas Pipeline sues the State of Oregon in federal court for delays. 10/15/10 – FERC issued a revised biological assessment Thursday that lists 12 protected species that could be harmed by the facility without adequate mitigation plans. **Jordon Cove recently announced a proposal to build a natural gas generation facility near their proposed LNG terminal.**
Canada		
Port of Kitimat LNG Facility Apache Corp Kitimat, British Columbia	0.64 (liquefaction)	1/13/09 – Kitimat signs agreement with Mitsubishi Corporation for LNG terminal. 3/16/09 – The proposed Pacific Trail Pipelines that would serve the Kitimat LNG project, has received approval from two Canadian regulatory bodies – Transport Canada and Fisheries and Oceans Canada. 6/2/09 - KOGAS signs MOU for 40% of Kitimat output. 7/7/09 – GAS NATURAL signs MOU for 30% of Kitimat output. 7/13/09 – Kitimat signs MOU with EOG Resources Canada to supply natural gas to the liquefaction facility. 8/10/09 – Apache signs MOU to supply Kitimat LNG with as much as 300,000 Mcf/d. 1/15/10 – Apache acquired a controlling 51% stake in Kitimat LNG, with Galveston LNG retaining 49%. 1/21/10 – Kitimat signs MOU with 'major' Japanese firm after MOU with Mitsubishi expired. EOG Canada acquires 49% from Galveston LNG Inc (May 2010). **10/27/10 – Korea Gas has begun commercial production at the Jackpine field in Canada, in which it holds a 50% stake.**

West Coast LNG Projects and Proposals
Status Update (12/7/10)

Note: Changes since last update are in **bold**.

Project Name, Company and Location	Average Production Capacity (Bcfd)*	Status
Texada Island LNG Facility WestPac LNG Corp. Texada Island, British Columbia	0.5	On June 6, 2006 Westpac filed its official Project Description with the Prince Rupert Port Authority, formally beginning the regulatory review and environmental assessment process for the project. 8/1/07 – WestPac LNG Corp. has abandoned plans for a $350-million liquefied natural gas terminal in Prince Rupert, B.C. and has proposed a $2-billion LNG terminal and power plant on Texada Island in the Strait of Georgia. WestPac LNG plans to file a detailed Project Description with the BC Environmental Assessment Office and the Canadian Environmental Assessment Agency in early 2009. **WestPac plans to put off filing its project description until the company has a better sense of new greenhouse gas (GHG) regulations that may come into effect.**
Mt. Hayes Storage Project Terasen Gas Vancouver Island, British Columbia **Note: This is a Peak Shaving facility not an Import facility.**	1.0	Terasen Gas first applied in 2004 for permission to build the facility. Terasen Gas plans to submit a new application in 2007 to the BC Utilities Commission. On June 5, 2007, Terasen Gas (Vancouver Island) Inc. submitted a new application to the BC Utilities Commission. On November 15, 2007, Terasen Gas received conditional approval from the BC Utilities Commission. **On April 1, 2008, Terasen Gas received final approval from the BC Utilities Commission to construct and operate a natural gas storage facility. Construction started in the month of April 2008. The new facility will be in service by 2011.**
Mexico		
Terminal GNL de Sonora El Paso Corp. and DKRW Energy LLC Sonora, Mexico	1.3	Mexico has issued three environmental permits for the Sonora LNG Project. Project managers are now attempting to secure potential LNG suppliers.

West Coast LNG Projects and Proposals
Status Update (12/7/10)

Note: Changes since last update are in **bold**.

Project Name, Company and Location	Average Production Capacity (Bcfd)*	Status
Energia Costa Azul LNG Facility Sempra Energy LNG Corp. Ensenada, Baja California	1.0	3/18/08 – The first cargo from Sakhalin 2 is scheduled to set sail for Tokyo Bay on March 28-29. 4/8/09 – Gazprom and Royal Dutch Shell has officially reached an agreement that would send LNG from Sakhalin 2 to Energia Coasta Azul in Baja California, Mexico. 5/15/09 – Tangguh startup has been delayed until July. 7/2/09 – Sempra expects to deliver first Tangguh cargo to Costa Azul this quarter. 8/5/09 – Tangguh train 2 could be delayed until October to supply Costa Azul due to technical problems. 8/28/09 - 1.45 Bcf from Tangguh 1 (before maintenance issues) arrived at Costa Azul on Saturday (8/29/09). 11/30/09 – Tangguh 1 is expected to be back online by the end of December. 4/22/10 – Costa Azul is to start receiving standard cargos of 3 Bcf every 12 days. 6/11/10 – The first LNG cargo from new Peru LNG plant will go to Costa Azul this week. 6/21/10 – Costa Azul terminal will continue to operate despite court order to suspend operations over land dispute. **6/29/10 – Mexican court revokes order to suspend Sempra terminal permit.**

**Bcfd = Billion cubic feet per day*

EXHIBIT I

Docket No. 07-AFC-6

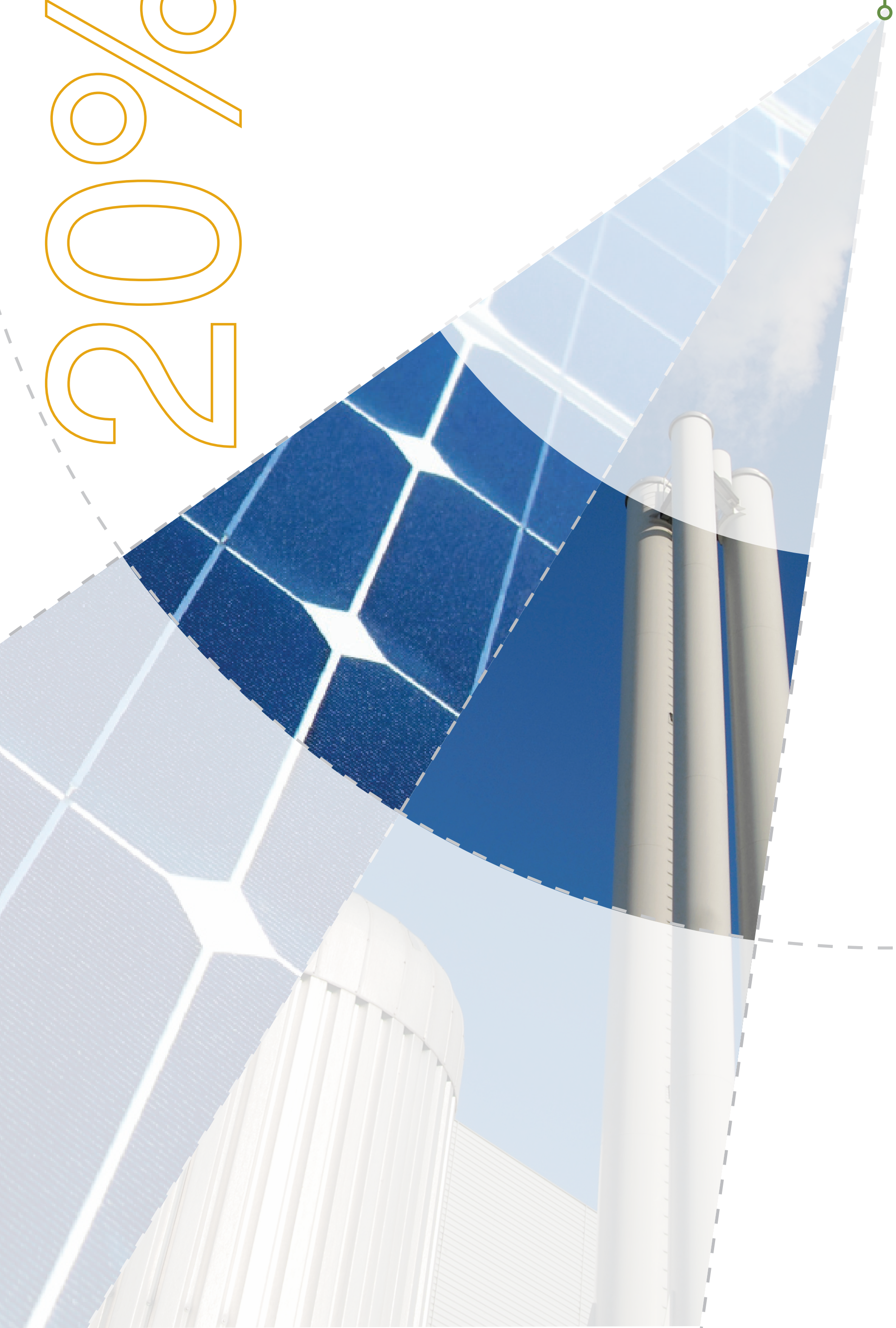
CENTER FOR BIOLOGICAL DIVERSITY'S RESPONSE IN SUPPORT OF CITY OF CARLSBAD'S MOTION TO TAKE OFFICIAL NOTICE AND THE CENTER'S MOTION TO TAKE OFFICIAL NOTICE AND RE-OPEN THE EVIDENTIARY RECORD

20% RPS

INTEGRATION OF RENEWABLE RESOURCES

Operational Requirements and Generation Fleet Capability at **20% RPS**

August 31, 2010



California ISO
Your Link to Power

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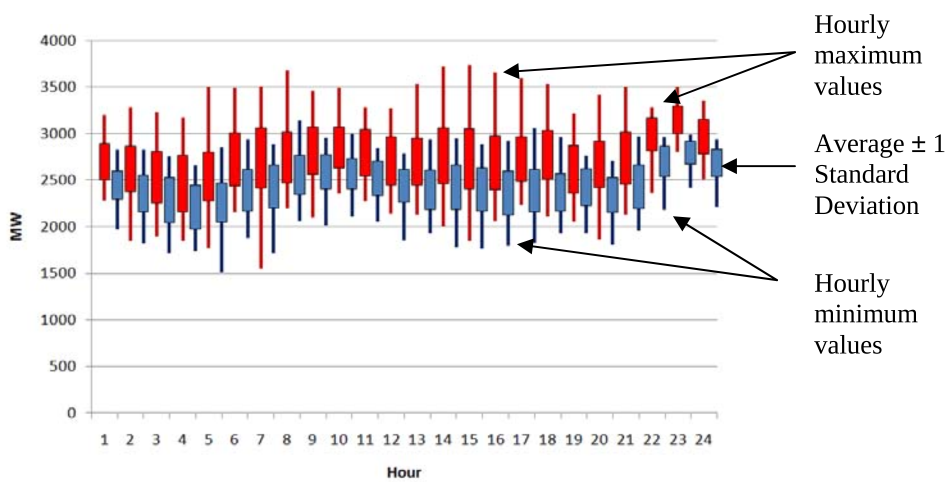
Preliminary Notes and Key to Figures

1. A number of the technical terms in this report refer to market products and market scheduling or operational procedures used by the ISO. Typically, such references are capitalized in ISO papers and reports to indicate that they are a defined term in the ISO Tariff. In this report, most technical terms are not capitalized and the use of acronyms is minimized to facilitate reading. For example, Regulation Up and Regulation Down are ancillary service products procured in the ISO markets, but are not capitalized in the report.

2. Many of the figures in the report represent data in the format of a "stock chart" or "whisker chart" that shows certain distribution statistics for a sample of simulated values or actual market results, typically shown by hour of season. In the example below, the top of the red or blue lines is the maximum data point in a sample, while the bottom of the red or blue lines is the minimum data point. The red and blue bars represent two standard deviations: the average plus one (1) standard deviation and the average minus one (1) standard deviation. Many of the figures, such as the one below, show these results for two simulated years that are being compared, in which case the results for each year are in different colors.



3. The figures in the report that use the format shown above are either measuring operational requirements in the upwards (positive) direction, which represent "incremental" energy or reserves, or in the downwards (negative) direction, which represents "decremental" energy or reserves. The figure above is for incremental energy, hence the vertical axis (or y-axis) is measuring positive values. For figures that show decremental energy or reserves, the y-axis shows negative values and the maximum and minimum of the sample data is reversed (i.e., the maximum requirement is the most negative).

4. In several sections of the report, readers need to distinguish between simulated results and actual results for the same or similar years. For certain simulations, the study benchmarks the results in the 20 percent RPS target year, assumed to be 2012, by simulation of prior years without the additional renewables, which in this study is 2006 and 2007. The study also includes analysis of actual ISO market and system conditions for selected periods up to 2010. The simulations of prior years, such as 2006, have been validated by comparison to actual conditions in those years, but there are differences due to modeling assumptions, as noted in the report.

Acronyms and Selected Definitions

ACE	Area Control Error
ADS	Automatic Dispatch Signal
AGC	Automatic Generation Control
BAA	Balancing Authority Area
BPM	Business Practice Manual
CEC	California Energy Commission
CPS	Control Performance Standard
CPUC	California Public Utilities Commission
DA	Day Ahead
EMS	Energy Management System
FERC	Federal Energy Regulatory Commission
FNM	Full Network Model
GW, GWh	Gigawatt, Gigawatt-hour (GW = 1,000 MW)
HA	Hour Ahead
HASP	Hour Ahead Scheduling Process
IFM	Integrated Forward Market
ISO	Independent System Operator
MW, MWh	Megawatt, Megawatt-hour (MW = 1,000 kW)
NERC	North American Electric Reliability Corporation
OTC	Once Through Cooling
PIRP	Participating Intermittent Resource Program
Pmin; Pmax	minimum and maximum operating level of a generator
PNNL	Pacific Northwest National Lab
PV	photovoltaic
QF	Qualifying Facility
RPS	Renewables Portfolio Standard
RT	Real Time
RTUC	Real Time Unit Commitment
WECC	Western Electricity Coordinating Council

Executive Summary

Under California's existing Renewables Portfolio Standard (RPS), utilities must supply 20 percent of all electricity retail sales from eligible renewable resources by 2010, with compliance expected in the 2011-2012 timeframe.[1] Much of the additional renewable generation to meet the RPS goal will be wind and solar technologies with variable operating characteristics that complicate electric system operations. As the entity responsible for the reliable operation of the bulk electric power system for most of the state, the California Independent System Operator Corporation (ISO) is focused on ensuring that the electric system is able to operate reliably with these additional renewable resources. This report represents an essential step in that effort. It describes the technical effects on system operations and wholesale markets of increases in wind and solar generation to achieve the 20 percent RPS target and evaluates the capability of the current generation fleet to maintain reliability under these changed conditions.

The chart below (Figure ES-1) shows the expected technology mix of renewable resource capacity assuming the 20 percent RPS is achieved in 2012 and compares it to the renewable resources in 2006, which is the year used to benchmark a number of study results.[2] Much of the expansion in renewable energy will come from variable energy resources, namely wind and solar technologies. The integration of variable energy resources will require increased operational flexibility—notably capability to provide load-following and regulation in wider operating ranges and at ramp rates that are faster and of longer sustained duration than are currently experienced. Forecast uncertainty associated with wind and solar production will increase the need for reservation of resource capacity to ensure that these requirements are met in real-time operations. There is also the likelihood of increased occurrence and magnitude of overgeneration, a condition where there is more supply from non-dispatchable resources, than there is demand. In providing these capabilities, the existing and planned generation fleet will likely need to operate longer at lower minimum operating levels and provide more frequent starts, stops and cycling over the operating day. Against this backdrop, certain conventional generators will also be operating at lower capacity factors due to the increased output from renewable energy generation.

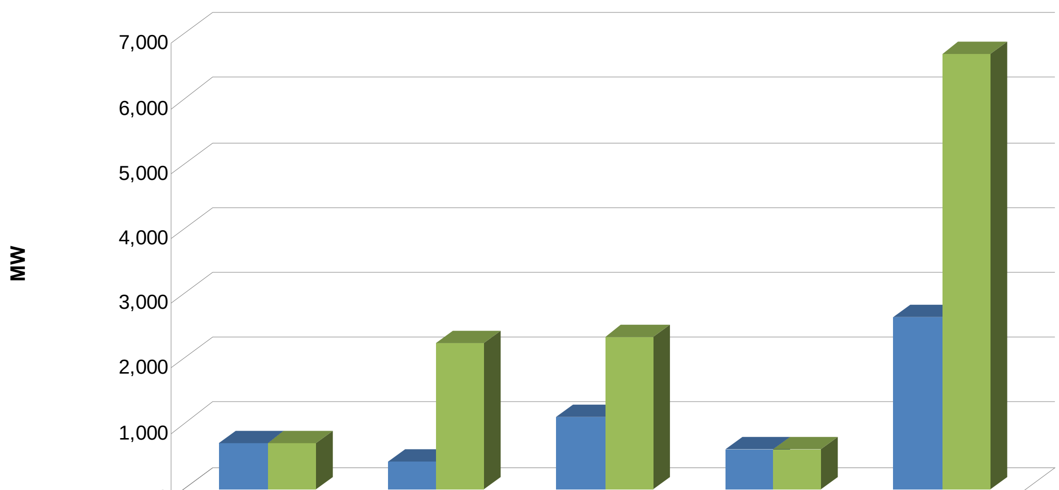
To understand the extent of these impacts at 20 percent RPS, the ISO has conducted several analyses, both collaboratively and independently, over the past several years, including a study released in 2007 that focused on the operational and transmission

[1] California Public Utilities Commission, "Renewables Portfolio Standard, Quarterly Report, 2nd Quarter 2010", at http://www.cpuc.ca.gov/NR/rdonlyres/66FBACA7-173F-47FF-A5F4-BE8F9D70DD59/0/Q22010RPSReporttotheLegislature.pdf.

[2] The year 2006 was chosen as the benchmark year to facilitate easier comparison with prior ISO studies. This year was both a high hydro year—hence is useful as a base-year to examine the interaction of hydro and higher levels of wind production in overgeneration conditions—and had the highest annual peak load to date.

requirements of wind integration ("2007 Report").[3] This study builds on those prior efforts. The purpose of this study is to assess the operational impacts of an updated renewable resource portfolio that includes 2,246 MW of solar and to evaluate in more detail the operational capabilities of the existing generation fleet, as well as changes to their energy market revenues. The study utilizes several analytical methods, including a statistical model to evaluate operational requirements, empirical analysis of historical market results and operational capabilities, and production simulation of the full ISO generation fleet.

The results presented in this report have significant operational and market implications. From an operational perspective, the ISO is concerned with the extremes of potential impacts—in particular large, fast ramps that are difficult to forecast. A key purpose of the simulations in this study is to estimate the operational capabilities and clarify possible changes to market and operational practices to ensure that the system can perform as needed under these conditions, even if they rarely occur. Hence, the study identifies the maximum values of simulated operating requirements, such as load-following and regulation, by operating hour and by season. In addition, to clarify how more typical daily operations may change, distribution statistics are provided for most of the simulated requirements and capabilities to facilitate both operational and market preparedness.



	Biomass/BioGass	Solar	Geothermal	Small Hydro	Wind
2006	701	420	1,101	614	2,648
2012 (expected)	701	2,246	2,341	614	6,688

Figure ES-1: Renewable Resource Capacity (MW) in 2006 and 2012 (expected)

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[3] California ISO, *Integration of Renewable Resources – Transmission and Operating Issues and Recommendations for Integrating Renewable Resources on the ISO-Controlled Grid* (Nov. 2007), available at http://www.caiso.com/1ca5/1ca5a7a026270.pdf.

Key Findings and Results

- The modeling of 2,246 MW of solar resources under the 20 percent RPS changes the operational requirements, compared to the incremental wind-only results presented in the ISO's 2007 Report.

- The changes to the operational requirements due to additional solar resources take place in the mid-morning and early evening hours. The ramp up in solar generation in the mid-morning can increase the load-following down and regulation down requirements compared to the case with wind generation alone that was studied in 2007. Similarly, the solar ramp down in early evening can increase the load-following up and regulation up requirements compared to the case with wind alone.

- In other hours, the combination of solar and wind resources can lessen operational requirements, because solar resources are ramping up when wind resources are ramping down, and vice-versa.

- The combination of increased production of wind and solar energy will lead to displacement of energy from thermal (gas-fired) generation in both the daily off-peak and on-peak hours. Due to this displacement and to simultaneous reduction in market clearing prices, there may be significant reductions in energy market revenues to thermal generation across the operating day in all seasons.

Load-following Impacts

A core operational and market function of the ISO is to forecast system load and renewable production day-ahead and in real-time, and then to ensure that sufficient generation and non-generation resources are committed such that intra-hourly deviations from hourly schedules can be accommodated by those resources under ISO dispatch control. These deviations can take place in the upward or downward direction. Currently, the intra-hourly deviations are largely caused by changes in load, hence the term "load-following." With additional variable energy resource production, the *net* load-following requirement—i.e., the requirement due to load schedule deviations plus wind and solar schedule deviations—could increase substantially in certain hours due both to the variability of wind and solar production and forecast uncertainty. Unless otherwise indicated, all results on load-following requirements in this report are of net load following.

- The simulated maximum load-following up and load-following down ramp rates for 2012, by season in which they occur, are 194 MW/min (summer) and -198 MW/min (winter), respectively.[4] These represent possible increases at times in the range of ± 30-40 MW/min over the ramp rates simulated for the year 2006.

[4] The load-following ramp rate measures the change in energy requirements between 1-minute intervals within the 5-minute dispatch intervals in an operating hour. The details behind the calculation of load-following ramp rate can be found in Section 3.

- While the system must be capable of delivering these capabilities, such ramp rates will not be experienced in every operational hour, nor sustained over the entire hour.

- One measure of the upper bound on the duration of the increased ramp rates is the hourly load-following capacity requirement.[5] The maximum hourly load following up and load-following down capacity requirements for 2012 are 3737 MW and -3962 MW (both summer season requirements), respectively. For the summer months, the maximum increase in the hourly capacity requirement when 2012 is compared to 2006 is 845 MW for load-following up and -930 MW for load-following down. As shown in Figures ES-2 and ES-3, in the summer, the highest requirements are typically in the morning and evening wind and solar ramp periods.

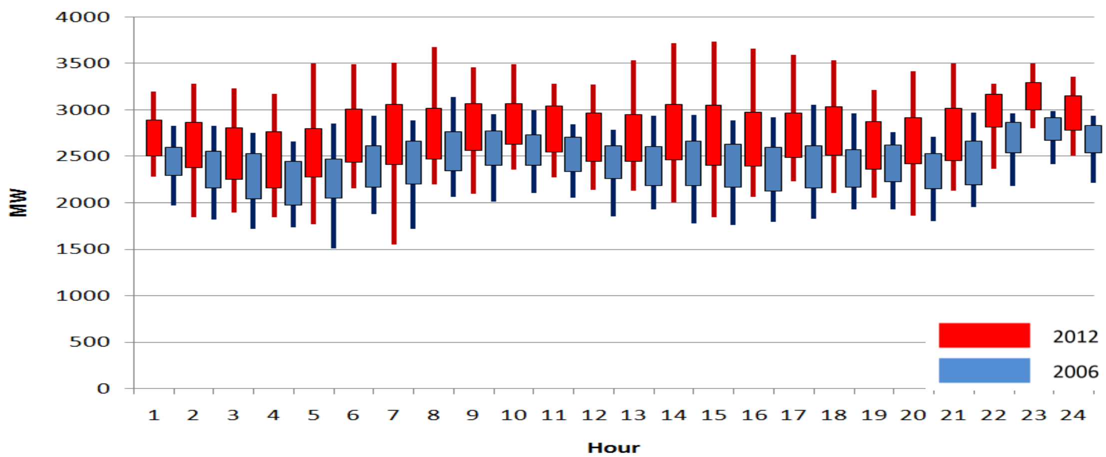

Figure ES-2: Simulated Load-following Up Capacity Requirement by Operating Hour, Summer, 2006 and 2012

[5] The hourly load-following capacity requirement is defined as the maximum difference between each hour-ahead schedule and the 5-minute real-time schedules within that hour. This can be measured in the upward or downward direction from the hourly schedule.

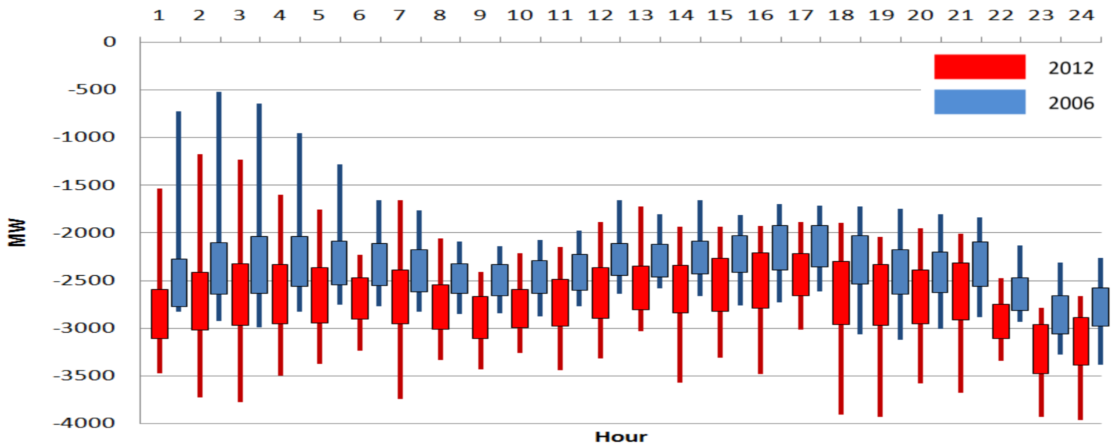

Figure ES-3: Simulated Load-following Down Capacity Requirement by Operating Hour, Summer, 2006 and 2012

- When the simulated maximum requirements for all hours in the season are taken into account, the percentage increase in total load-following capacity requirements in the summer season between 2012 and 2006 is estimated at 12 percent for load-following up and 14 percent for load-following down; the results for all seasons are shown in Table ES-1.[6]

Table ES-1: Percentage Increase in Total Seasonal Simulated Operational Capacity Requirements, 2012 vs. 2006

	Spring	Summer	Fall	Winter
Total maximum load-following up	27.0 %	11.9 %	19.2 %	19.7 %
Total maximum load-following down	29.5 %	14.0 %	21.2 %	21.3 %
Total maximum regulation up	35.3 %	37.3 %	29.6 %	27.5 %
Total maximum regulation down	12.9 %	11.0 %	14.2 %	16.2 %

- The historical 5-minute load-following capability[7] of the generation fleet, was measured for the period between April 1, 2009, and June 30, 2010. Figures ES-4 and ES-5 show the 5-minute load-following up and load-following down capability for units on 5-minute dispatch in the summer months during that period.[8] The results show that the ISO dispatch in recent months appears, for the majority of intervals analyzed, to be able to meet the load-following up

[6] The total is defined as the sum of the maximum simulated load-following capacity requirement in each hour of the season (2160 hours = 90 days × 24 hrs./day for a 90 day season); see Section 3 for details.

[7] The 5-minute load-following up (down) capability for a dispatch interval is the *maximum* capability that is available in the up (down) direction in 5-minutes, subject to the ramp rates and operational constraints of the dispatched resources.

[8] In the figures, each bar corresponding to an operating hour represents 1080 measurements for a 90 day season; e.g., for hour 1, each 5-minute interval of that hour for each of the 90 hour 1s in the season.

requirements simulated for 20 percent RPS within 20 minutes or less.[9] This is simply due to the ramp capacity remaining on units not dispatched to their maximum operating levels, and not to any preparations made by the ISO to address renewable integration.

- The simulated maximum load-following down ramp rate for summer in 2012 was -169 MW/min, which is -845 MW/5 min. These high load-following down requirements are often for the mid-morning hours. Under the current practice of self-scheduling generation rather than allowing them to be operated through economic dispatch, the 5-minute downward ramp capability as shown in Figure ES-5 could be well below the requirement of -845 MW during some of the mid-morning hours.

- Figures ES-5 and ES-6 compare the 5-minute load-following down capability, limited and not limited by self-schedules, respectively. Figure ES-6 suggests that current load following down capability could be more than doubled in many hours if all thermal generation were fully dispatchable. The implication is that to accommodate the increased variability at 20 percent renewable energy, the level of self-schedules will have to decrease.

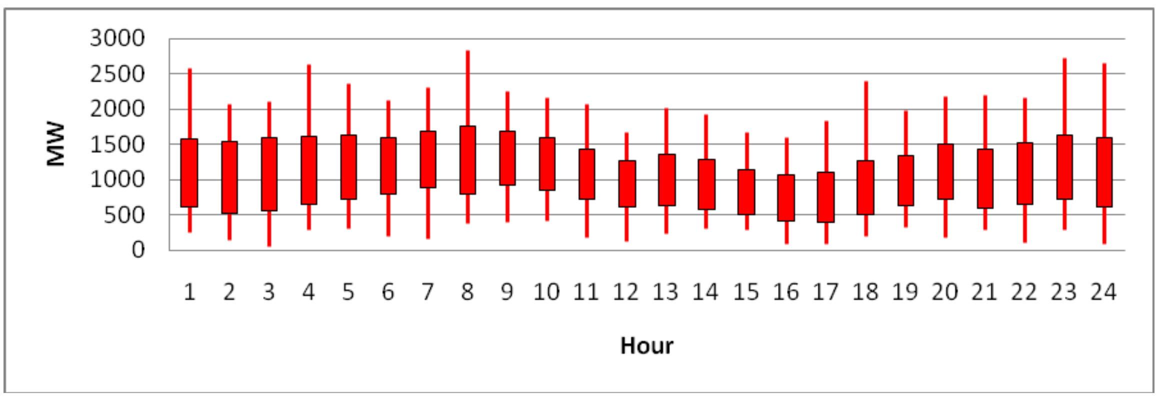

Figure ES-4: Summer 5-Minute Load-following Up Capability: June 2009-August 2009, June 2010

[9] For example, if the 3,737 MW maximum load-following up capacity has to be met within 20 minutes of the start of the hour, the results suggest that in most hours, the current system ramp could on average in most hours sustain 1000 MW/5-minutes or more, meaning that the requirement could be met and slightly exceeded in 4 such intervals.

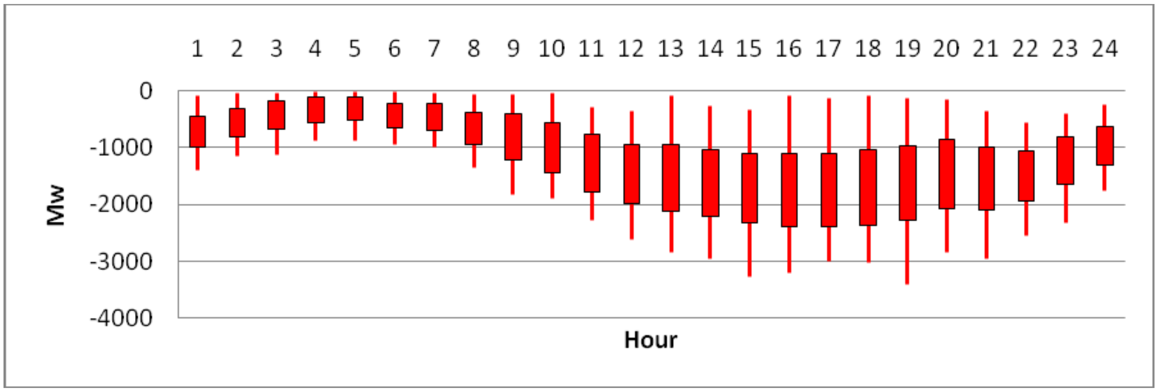

Figure ES-5: Summer 5-Min Load-following Down Capability (Limited by Self Schedules): June 2009-August 2009, June 2010

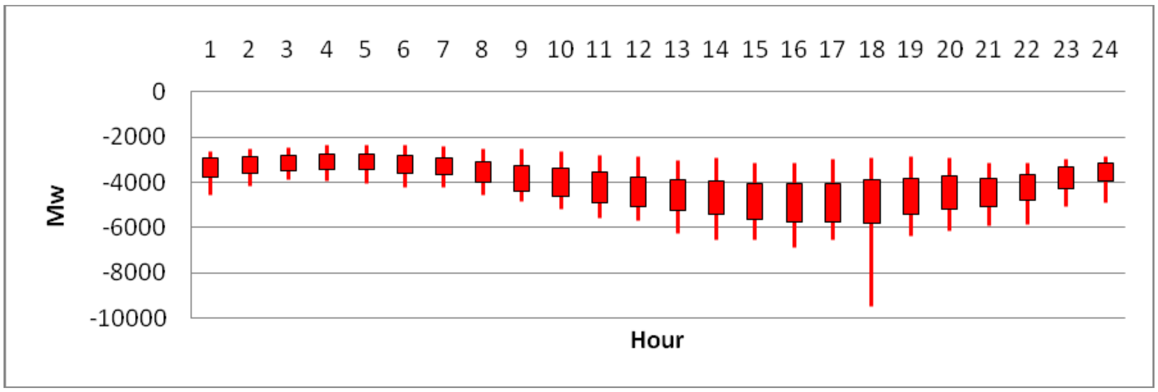

Figure ES-6: Summer 5-Minute Load-following Down Capability (not limited by Self-Schedules): June 2009-August 2009, June 2010

To further evaluate the load-following up and down capabilities of the ISO generation resources, the ISO also conducted production simulations for selected days that included simulation of 5-minute dispatch. The production simulation assumed that all thermal generation were fully dispatchable (i.e., maximum operational flexibility), but that all other classes of generation were following fixed schedules.

- Figure ES-7 shows the load-following capability over one such simulated day, May 28, 2012. This figure shows the capability of the dispatchable generators to move from one 5-minute dispatch to the next, subject to ramp and other operational constraints.[10] The 5-minute load-following down capability is at or

[10] It should be noted that Figure ES-7 shows the simulated load-following capability for each 5-minute period in the day, whereas Figure ES-5 shows the historical hourly distribution of 5-minute load-following capability.

close to zero during the morning hours from 4 a.m. to 10 a.m.[11] as shown. If current scheduling practices continue, this simulated capability would be further diminished due to self-scheduling. Production simulation results for additional days can be found in Section 5 and Appendix C.

- Figure ES-8 then shows the simulated overgeneration on May 28, 2012 due to the shortage of load-following down capability. Insufficient capability to ramp down manifests itself as overgeneration in the production simulations.[12] This figure also shows the regulation down procurement (green line) and the CPS2[13] violation threshold (yellow line) for the same period. While there is significant, sustained overgeneration for a few hours from 5 a.m. to 8 a.m., for the other hours in the day, the overgeneration can be covered by the procured regulation down or allowed to result in an Area Control Error (ACE) violation, if it is not sustained. Only significant overgeneration sustained over 10 minutes is likely to result in the curtailment of generation.

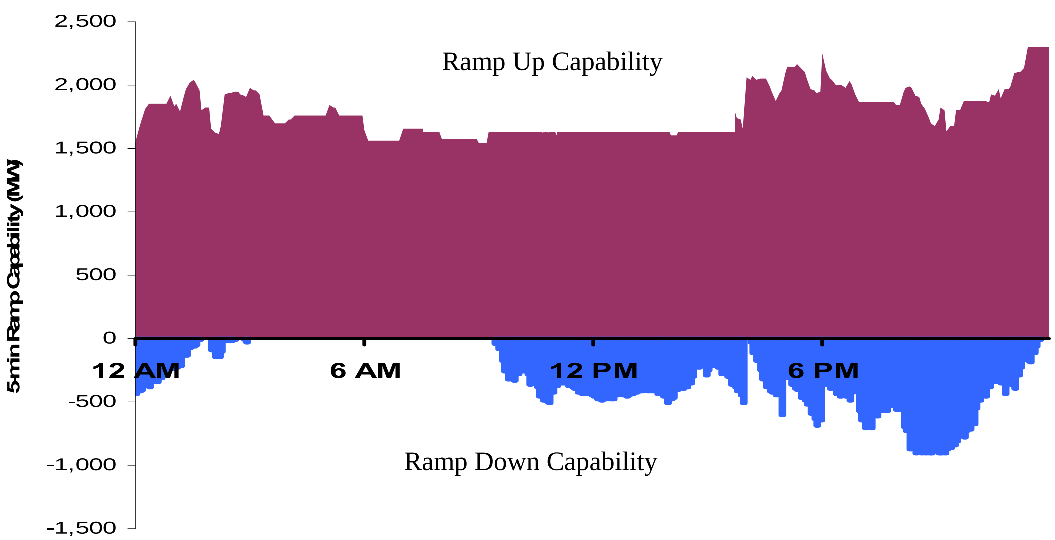

Figure ES-7: 5-minute ramp up and down capability for May 28, 2012

[11] The low load-following down capability in the simulation is because very few dispatchable generators are online and most are already operating at or close to their minimum load point. When operators can no longer dispatch resources downwards, the operating condition called overgeneration exists and is managed through additional measures, including curtailments of renewable resources.

[12] As discussed further in Sections 2 and 5, there were further constraints in the model that affected the overgeneration result.

[13] NERC Control Performance Standard 2.

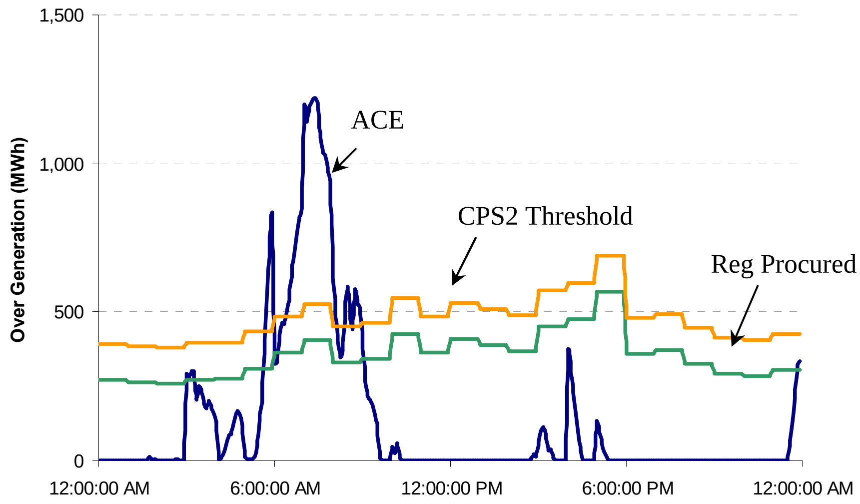

Figure ES-8: Detailed overgeneration analysis of May 28, 2012

- For the year, production simulations show that load-following down shortages will result in less than 0.02 percent of renewable generation (approx. 10 GWh) potentially needing to be curtailed under assumed conditions. The production simulations did not identify any load-following up shortages.

Regulation Impacts

In real-time, the ISO operators issue dispatch instructions to generators every 5 minutes based on forecasts of demand and supply that are available in the prior minutes. The second-by-second variability of load, net of wind and solar production, within those 5-minute intervals is balanced by units on automatic generation control (AGC) that can provide regulation as needed in the upwards or downwards direction.

- The maximum hourly regulation up and regulation down capacity requirements in 2012, which take place in different seasons, are 502 MW (spring) and -763 MW (summer), respectively. The largest increases in these requirements between the 2012 and 2006 simulations are 270 MW (spring) and -457 MW (summer). These results are found in Appendix A-1, tables A-1 to A-8.

- As shown in Figures ES-9 and ES-10 for the summer 2012 season, the highest regulation up requirements are typically in the morning and evening wind and solar ramp periods, while regulation down requirements are concentrated in the mid-afternoon hours. Hour 18 consistently results in very high regulation down requirements in the summer simulations, due largely to the consistently fast wind ramp up experienced in that hour.

- The maximum hourly simulated regulation up and regulation down ramp rates in 2012 are 122 MW/min (spring) and -97 MW/min (summer), respectively, compared to 75 MW/min and -79 MW/min, respectively, for simulated 2006 levels.

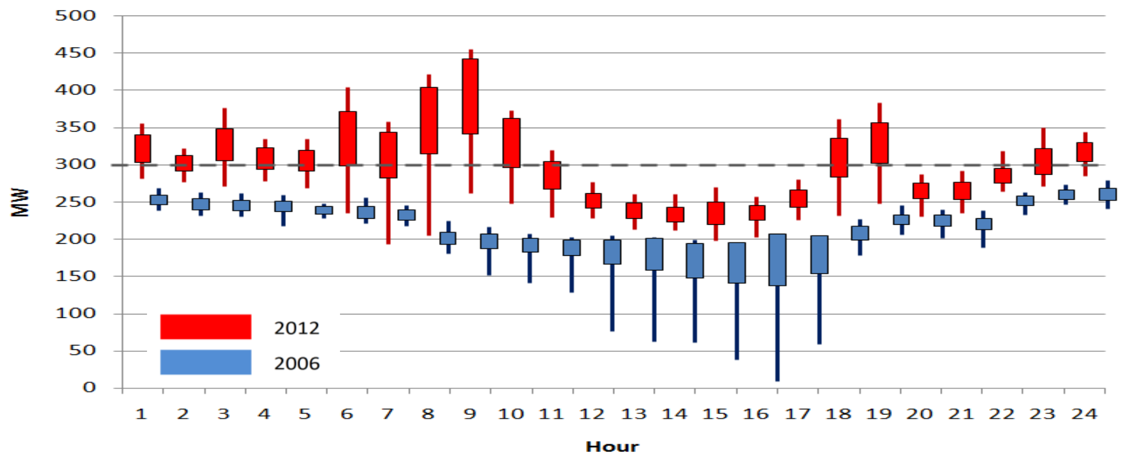

Figure ES-9: Simulated Regulation Up Capacity Requirement by Operating Hour, Summer, 2006 and 2012

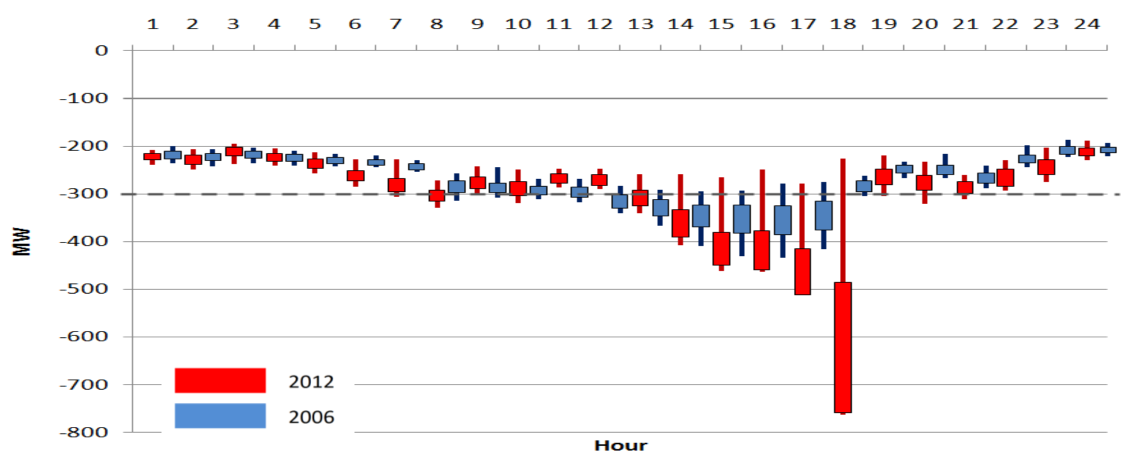

Figure ES-10: Simulated Regulation Down Capacity Requirement by Operating Hour, Summer, 2006 and 2012

- The simulated percentage change in total regulation capacity requirements in the summer season between the 2012 and 2006 simulations is estimated at 37 percent for regulation up and 11 percent for regulation down (as shown in Figure ES-10, most of the regulation down increased requirement is concentrated in three afternoon hours); the results for other seasons are shown in Table ES-1.[14]

- The regulation results require several important clarifications. First, the ISO currently procures 100 percent of its regulation requirement in the day-ahead

[14] The total is defined as the sum of the maximum simulated regulation capacity requirement in each hour of the season; see Section 3 for details.

market, with a minimum requirement in the range of 300 MW in the upwards and downwards direction. First, the simulation does not consider the effect of day-ahead wind and solar production forecast errors on determining the forecast next day regulation need. Second, there are other uncertainties factored into regulation procurement, such as actual uninstructed deviations from dispatch instructions that are not considered in the simulation. Hence, the simulated results shown here may understate the ISO's actual regulation needs, but are indicative of future increases in regulation procurement.

- The additional regulation requirements appear to be well within the capabilities of the existing generation fleet. The ISO regulation markets have procured levels of regulation up and regulation down since April 1, 2009, in the range of 600-700 MW in each hour of the operating day, with these high procurements largely taking place during the first month of market implementation to ensure reliability. These procurement levels provide one test of the ISO's ability to meet the higher regulation requirements that could be experienced under 20 percent RPS.

- Moreover, as another indicator of current regulation capability, the 5-minute regulation ramp capability of the generation resources committed and dispatched in each hour of the day since April 1, 2009, has been measured and determined to be above the calculated regulation requirements under 20 percent RPS for most hours.[15] Hence, the empirical analysis suggests that deficiency of regulation capability should not be a problem except in the hours of overgeneration, when regulation down may be in shortage.

Overgeneration Impacts

- The production simulations analyzed both a high hydro year (based on 2006 hydro production) and a low hydro year (based on 2007 hydro production), as well as sensitivities to assumptions about load growth and firm imports, to evaluate their effect on overgeneration. The maximum overgeneration occurred in a scenario that assumed no load growth between 2006 and 2012. The overgeneration in this case was approximately 0.3% (150 GWh) of annual renewable generation.

- Most of the overgeneration occurs in late spring (April-May), due to combination of high generation from hydro and variable energy resources, and low loads. In general, overgeneration was found to be directly correlated to the amount of non-dispatchable generation in the system. There appears to be sufficient dispatchable generation available to operate if the ISO is not prevented from doing so due to an excess of non-dispatchable generation, including imports.

[15] This is a rough measure of how much additional regulation capacity could be procured if units were converted from providing energy or other ancillary services to regulation.

Fleet Operations and Economic Impacts

- The increased supply variability associated with the 20 percent RPS results in the dispatched gas-fired generators starting and stopping more frequently. In an hourly simulation of 2012, combined cycle generator starts increase by 35 percent compared to a reference 2012 case[16] that assumes no new renewable capacity additions beyond 2006 levels. Also, the energy from the combined cycle units reduces by roughly 9 percent on an average, with more reduction occurring during off-peak hours when there wind production is highest, indicating more cycling in the dispatchable fleet.

- The lower capacity factors combined with the reduced energy prices under 20 percent RPS may result in a significant drop in energy market revenues for the gas fleet in all hours of the day and in all seasons. Tables ES-2 to ES-4 show the change in simulated annual energy revenues for three types of gas resources: combined cycle units, simple cycle gas turbines, and gas-fired steam turbines. These simulated revenue results, based on marginal production costs, are provided to illustrate potential changes in energy market revenues rather than as a forecast; actual market prices will reflect factors not considered, or only partially considered, in the model, such as congestion and the effect on prices of market bids. Also, revenues from ancillary services are not included in the annual revenues.

Table ES-2: Aggregate Operational, Emissions and Revenue Changes for Combined Cycle Units, 2012

	20% RPS case	2012 Reference case	Percent change
Number of starts	3,362	2,492	35 %
On-peak Energy (MWh)	32,421,142	36,258,580	-11 %
Off-peak Energy (MWh)	26,146,347	31,055,863	-16 %
CO2 Emissions (tons)	24,266,005	27,969,588	-13 %
Revenue ($,000)	3,455,290	4,103,959	-16 %

Table ES-3: Aggregate Operational, Emissions and Revenue Changes for Simple Cycle Gas Turbines, 2012

	20% RPS case	2012 Reference case	Percent change
Number of starts	9,618	12,123	-21 %
On-peak Energy (MWh)	6,223,446	10,244,121	-39 %
Off-peak Energy (MWh)	3,359,432	5,034,037	-33 %
CO2 Emissions (tons)	5,591,607	8,660,370	-35 %
Revenue ($,000)	605,167	996,017	-39 %

[16] The only difference between the 2012 reference case and the 20% RPS case is the amount of renewable energy. Both cases use the same load and other assumptions.

Table ES-4: Aggregate Operational, Emissions and Revenue Changes for Gas-fired Steam Turbines, 2012

	20% RPS case	2012 Reference case	Percent change
Number of starts	2,653	3,392	-22 %
On-peak Energy (MWh)	5,109,377	7,179,751	-29 %
Off-peak Energy (MWh)	3,396,360	4,125,934	-18 %
CO2 Emissions (tons)	3,654,106	4,598,358	-21 %
Revenue ($,000)	522,329	735,255	-29 %

Study Recommendations

Based on the study results, the following recommendations are made.

- **Evaluate market and operational mechanisms to improve utilization of existing generation fleet operational flexibility.** The study confirmed that the generation fleet possesses sufficient overall operational flexibility to reliably integrate 20 percent RPS in over 99 percent of the hours studied. However, the current markets do not reveal that full capability due to self-scheduling. In particular, the empirical analysis demonstrated the shortage of the 5-minute load-following capability in the downward direction when resources are self-scheduled, as compared to offering their actual physical capabilities for economic dispatch. These results were further substantiated using production simulation. Hence, the study makes clear that the ISO should pursue incentives or mechanisms to reduce the level of self-scheduled resources and/or increase the operating flexibility of otherwise dispatchable resources.

- **Evaluate means to obtain additional operational flexibility from wind and solar resources.** The simulations demonstrated the need for additional dispatchable capacity in the morning hours under certain conditions. The ISO should explore market rules and incentives intended to encourage greater participation by wind and solar resources in the economic dispatch. Greater economic dispatch control, including curtailment and ramp rate limitations, can be used in targeted circumstances to mitigate overgeneration or shortfalls in regulation and load-following capability generally.

- **Improve day-ahead and real-time forecasting of operational needs: (a) Develop a regulation prediction tool.** The analysis demonstrated that regulation needs will vary substantially from hour to hour depending on the expected production from wind and solar resources. The development of a tool to forecast the next day's hourly regulation needs based on probabilities of expected renewable resource output would enhance market efficiency.

- **Improve day-ahead and real-time forecasting of operational needs: (b) Develop a ramp/load-following requirement prediction tool.** The ISO should accelerate the development of improved forecasting of operational ramps generally and load-following requirements on different intra-hourly time frames. This capability could be complemented by evaluation of whether to modify unit commitment algorithms and procedures to reflect those forecast ramp requirements.

- **Further analysis to quantify operational and economic impacts on fleet at higher levels of RPS.** Although this study was not focused on the impact of renewable integration on the revenues of existing generation, it has provided some indications of possible changes in such revenues, primarily through changes in energy market prices. Further analysis is needed to clarify the net revenue impact from changes in procurement and prices for wholesale energy and ancillary services as well as the implications for payments through resource adequacy contracts.

1 Introduction

California's existing Renewables Portfolio Standard (RPS) requires utilities to achieve their statutory obligation to supply 20 percent of all consumed electricity from eligible renewable resources by 2010. Compliance with this level is now anticipated in the 2011-2012 timeframe and will likely depend on load growth, contract implementation, and other factors.[17] The California Independent System Operator Corporation (ISO), along with the California state agencies and the electric power industry, is conducting the substantial planning, along with the operational, technological and market changes, needed in the power sector to accommodate this higher level of renewables.

The majority of new renewable generation capacity needed to realize the state's 20 percent RPS goal likely will come from additional variable energy resources, primarily wind and solar technologies.[18] The key operational characteristics of such resources are the variability of their generation over different operational time-frames (seconds, minutes, hours) and the uncertainty associated with forecasting their production (i.e., forecast error). As such, the integration of variable energy resources will require increased operational flexibility—notably capability to provide load-following and regulation in wider operating ranges and at ramp rates that are faster and of longer sustained duration than are currently experienced. Forecast uncertainty associated with wind and solar production will increase the need for reservation of resource capacity to ensure that these requirements are met in real-time operations. There is also the likelihood of increased occurrence and magnitude of overgeneration, a condition where there is more supply from non-dispatchable resources than there is demand. In providing these capabilities, the existing and planned generation fleet will likely need to operate longer at lower minimum operating levels and provide more frequent starts, stops and cycling over the operating day. Against this backdrop, certain conventional generators will also be operating at lower capacity factors due to the increased output from renewable energy generation.

The ISO provides open access to the transmission system under its control while simultaneously operating the grid and markets for energy, ancillary services and

[17] California Public Utilities Code Section 399 requires that the RPS objectives be achieved by 2010, with some accommodation for deferred compliance under specified circumstances. In 2009, the California investor-owned utilities served 15.4 percent of their load with renewable energy eligible under the RPS. In late 2009, the California Public Utilities Commission (CPUC) estimated that the 2010 deadline would not be met and that 2013-14 was more realistic. However, in mid-2010, based on declines in electricity consumption, rapid growth in RPS contract approvals (including short-term contracts for out-of-state wind energy), and other factors, the CPUC estimated that the 20 percent target could be reached in 2011. In this study, the ISO models 20 percent renewable energy in 2012. See CPUC, Renewables Portfolio Standard, Quarterly Report (Q4 2009), at p.4, and CPUC, Renewables Portfolio Standard, Quarterly Report (2nd Quarter 2010), at p. 3, both available at http://www.cpuc.ca.gov/PUC/energy/Renewables/documents.htm.

[18] "Variable energy resources" is the term being used by the Federal Energy Regulatory Commission to describe renewable resources that have variable or intermittent production. Variable energy resources is thus used here as an equivalent term to "intermittent resources". Not all renewable resources eligible under renewable portfolio standards are variable energy resources. For example, geothermal, biogas and biomass resources generally follow fixed hourly schedules.

congestion revenue rights. The design of the ISO's integrated wholesale market and system operations has the capability to significantly facilitate renewable integration. There are both day-ahead and real-time markets that optimize the utilization of system resources using state-of-the-art software, while accounting for key constraints on electric power production such as generation unit operating characteristics and transmission congestion and losses. During the operating day, the ISO now has more accurate procedures to adjust market resources in response to changing real-time conditions, with dispatch instructions sent every five minutes. This allows for more efficient use of system resources in following the output of variable energy resources, like wind and solar. As a result, the redesigned market will allow more renewable energy to be integrated into the system.

As the entity with primary responsibility for the continued reliable operation of the electric transmission, the ISO needs to evaluate the effects on system and market operations of integrating 20 percent RPS. If necessary, the ISO will take action to facilitate renewable integration and address any adverse effects on market functioning and reliability. In this regard, the ISO has conducted several analyses, both collaboratively and independently, over the past several years, including a study in 2007 focused on the operational and transmission requirements of wind integration ("2007 Report").[19] This report builds on those efforts. The study utilizes several analytical methods, including a statistical model to evaluate operational requirements, empirical analysis of historical market results and operational capabilities, and production simulation of the full ISO generation fleet.

1.1 Report Organization

The report is organized as follows. The remainder of this section provides background on the impacts of generation from variable energy resources on operations and market functions and identifies the specific objectives of this study. Section 1.2 reviews the mix of resources projected to fulfill California RPS requirements by 2012. Section 1.3 discusses the characteristics of generation from variable energy resources and how they impact system operations. Section 1.4 sets forth the specific objectives of this study and also discusses how this study builds upon prior work.

Section 2 then provides an overview of the simulation methodologies and the scenarios that were modeled in this study. Section 3 discusses the results of the simulations that were used to determine the operational requirements, i.e., regulation and load-following requirements, under 20 percent RPS. Section 4 describes the results of the empirical analysis performed to assess the historical capability of the fleet and how it compares

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[19] California ISO, *Integration of Renewable Resources – Transmission and Operating Issues and Recommendations for Integrating Renewable Resources on the ISO-Controlled Grid* (Nov. 2007) at http://www.caiso.com/1ca5/1ca5a7a026270.pdf. Another recent report on renewable integration using ISO data by KEMA titled, "*Research Evaluation of Wind Generation, Solar Generation, and Storage Impact on the California Grid* (June 2010)" can be found at http://www.energy.ca.gov/2010publications/CEC-500-2010-010/CEC-500-2010-010.PDF.

with the future operational requirements. Section 5 presents the results of the production simulations used to test the capability of the fleet to meet the operational requirements with and without the 20 percent RPS in 2012. Finally, Section 6 provides recommendations.

Similar to the 2007 Report, this report includes a set of appendices that provide additional results and selected discussion of methodology. There is also a separate technical appendix that provides mathematical formulations of the models and other information on how renewable production profiles and forecast errors were developed.

1.2 California Renewable Portfolio Standards

After several years of fairly static energy production from renewable resources, the next few years could see a significant increase in production each year, with the great majority from variable energy resources. In 2009, California investor-owned utilities collectively served 15.4 percent of their load with renewable energy. In late 2009, the California Public Utilities Commission (CPUC) forecast that 20 percent RPS would be achieved by 2013-2014. More recently, the CPUC estimates that utilities are expected to have procured approximately 18 percent renewable energy in 2010 and over 20 percent by 2011 based on signed renewable resource contracts.[20]

Much of the incremental renewable deliveries anticipated over the next couple of years to achieve the RPS target will be from operational out-of-state resources, many of which have signed short-term contracts with California utilities. Under current scheduling practices, the Balancing Area Authority (BAA) exporting the renewable energy to California will be largely responsible for managing the variability and uncertainty of the renewable resources interconnected to its system. This has the potential to mitigate the integration requirements confronting the ISO in the near-term. However, as those short-term out-of-state contracts expire, they will generally be replaced by power purchase agreements with in-state renewable resources.[21] Existing out-of-state resources may also seek dynamic transfer arrangements with the ISO. Both of these circumstances will shift the integration requirements to the ISO.

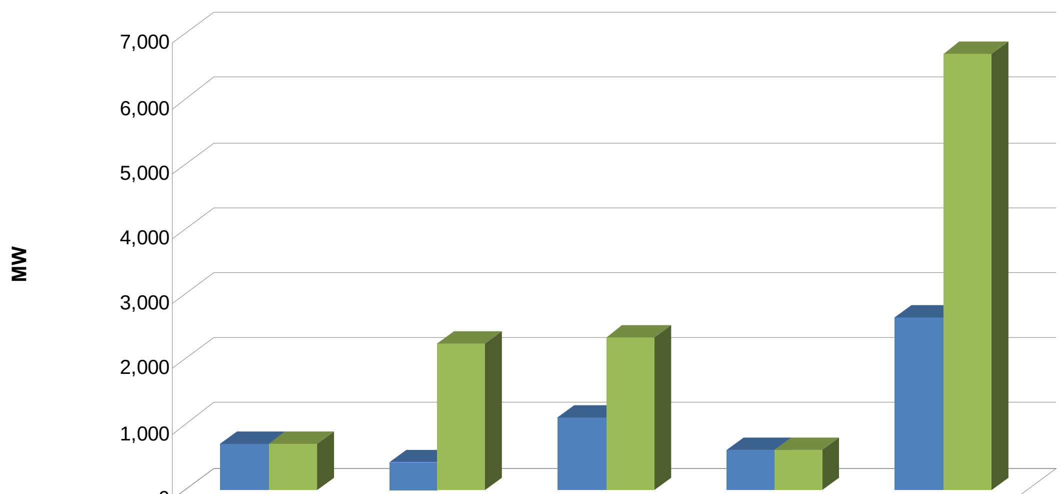
This study assumes that most of the renewable generation is in-state and within the ISO BAA – or equivalently that a high proportion of the in-state and out-of-state resources located outside the ISO BAA are dynamically transferred into the ISO. Such an assumption is not only consistent with the longer-term trend of the utility contracts, but also comports with the ISO's objective in this study to test the capability of the existing fleet to provide the integration requirements within the ISO BAA at 20 percent RPS.

The renewable resource portfolio includes a wind resource forecast developed by the ISO and consultants, and adapts a forecast of expected solar and geothermal capacity

[20] California Public Utilities Commission, "Renewables Portfolio Standard, Quarterly Report, 2nd Quarter 2010", at http://www.cpuc.ca.gov/NR/rdonlyres/66FBACA7-173F-47FF-A5F4-BE8F9D70DD59/0/Q22010RPSReporttotheLegislature.pdf.

[21] For information on the status of RPS procurement activity by California's investor-owned utilities see the CPUC website at http://www.cpuc.ca.gov/PUC/energy/Renewables.

developed by the CPUC in 2009.[22] The renewable resource capacity (MW) and associated expected energy production (MWh) were adjusted, based on 2012 load forecasts, to provide approximately 20 percent energy from RPS-eligible resources. Figure 1-1 shows the renewable capacity modeled. The figure also shows the renewable generation portfolio modeled in the base-year of the study (2006). The year 2006 was chosen as the base year to facilitate easier comparison with the 2007 Report. Compared to the 2007 Report, this study evaluates an additional 1,826 MW of solar generation, comprised of 830 MW of solar photovoltaic (PV) and 996 MW of solar thermal resources, for a total of 2,246 MW of solar resources. Both the 2007 Report and this study assume 6,686 MW of wind resources by 2012.



	Biomass/BioGass	Solar	Geothermal	Small Hydro	Wind
2006	701	420	1,101	614	2,648
2012 (expected)	701	2,246	2,341	614	6,688

Figure 1-1: Renewable Resources in the Base Case and under 20 percent RPS scenarios

1.3 Potential Impacts in System Operations

As noted above, the majority of new renewable generation capacity needed to realize the state's 20 percent RPS goal likely will come from additional variable energy resources, primarily wind and solar technologies. This section discusses the impact of the generation variability and forecast uncertainty on power system operations.

[22] The portfolio was the CPUC 20 percent RPS reference case developed for its 33 percent RPS Implementation Analysis. See http://www.cpuc.ca.gov/NR/rdonlyres/1865C207-FEB5-43CF-99EB-A212B78467F6/0/33PercentRPSImplementationAnalysisInterimReport.pdf.

1.3.1 Variability of Wind and Solar Generation

The variability of wind and solar generation is measured over different time-scales. Beginning on the time-scale of minutes, Figure 1-2 shows the variability in wind and solar PV generation on a minute-by-minute basis over the full day. Figure 1-3 then shows those variations more closely on a sub-hourly basis. The implications for system operations are that, unless the variability is smoothed by the variable energy resource itself, other resources have to increment or decrement their generation on similar time frames (seconds, minutes, hours) to compensate for the supply variability. The ISO operational time frames and procedures by which this is done are discussed in the next section.

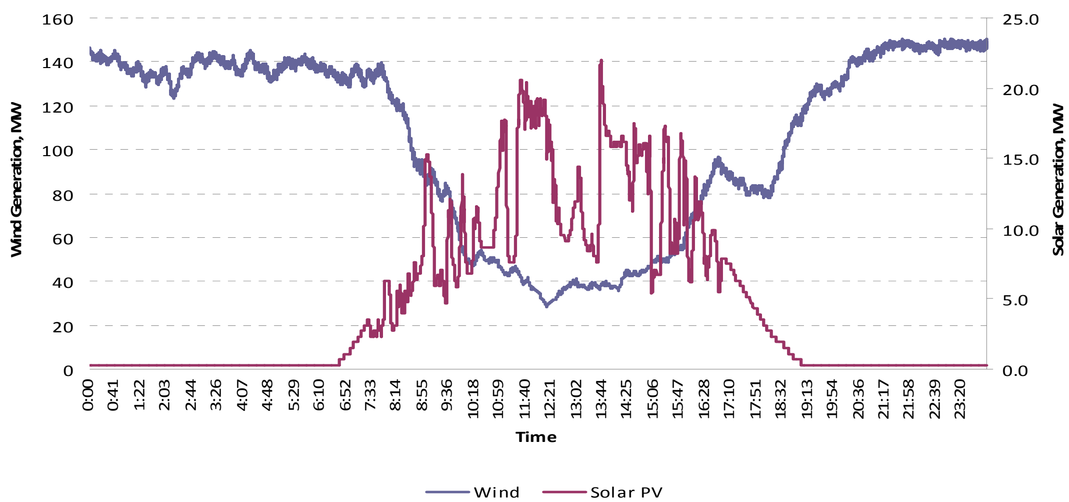


Figure 1-2: Sub-hourly wind and solar generation for a day for a 150 MW wind generator and a 24 MW Solar PV plant

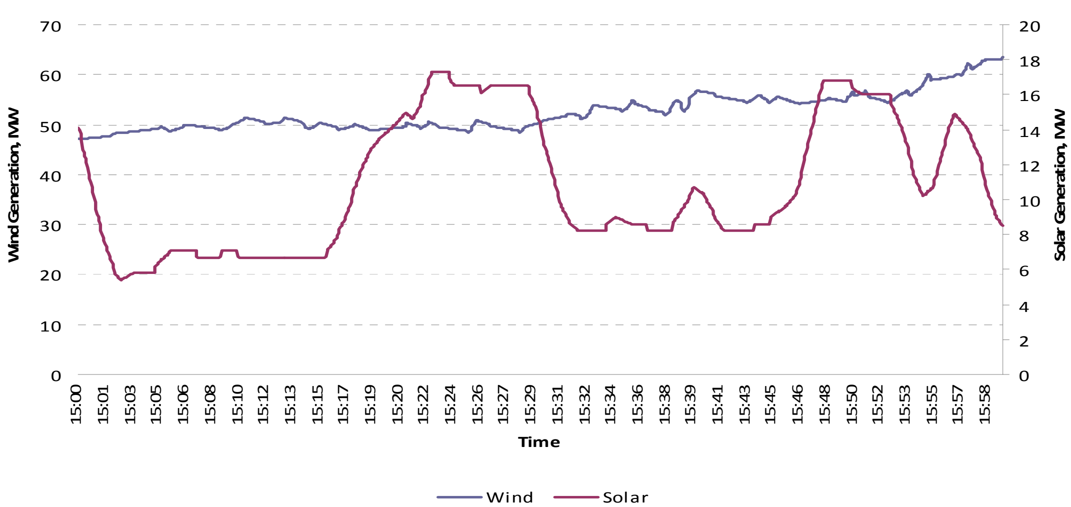


Figure 1-3: Sub-hourly wind and solar generation profiles for an hour

On any particular day, the multi-hour ramps associated with wind production, and the range of that production, can vary significantly. Figures 1-4 to 1-7 illustrate simulated high ramp days in every season in 2012 based on data on historical wind performance in California, in which total state-wide wind production can vary from almost full output to very low output in a few hours, and vice-versa. The simulated load and renewable energy production shown in these and subsequent figures are based on assumptions, data and methods described in Section 3.

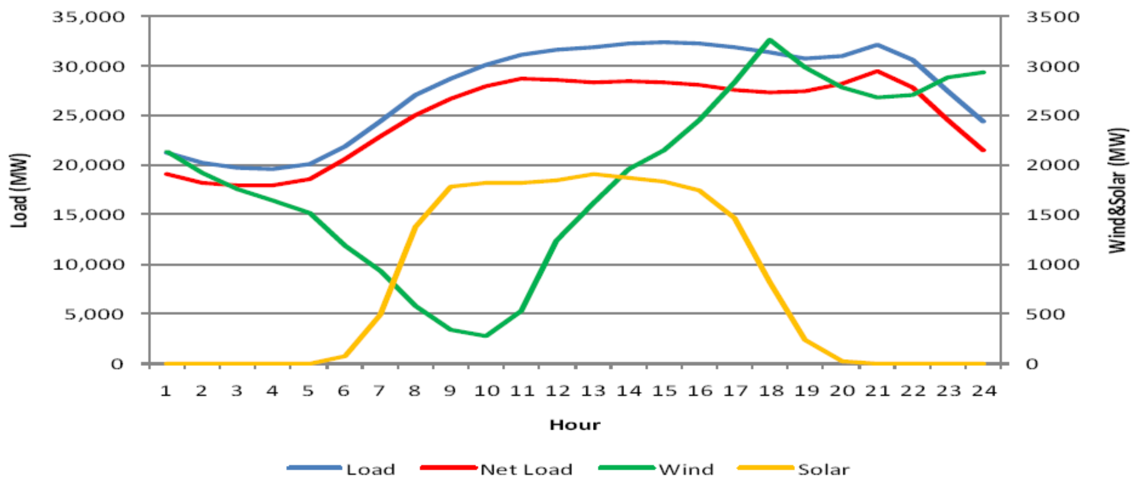


Figure 1-4: Simulated May 8, 2012

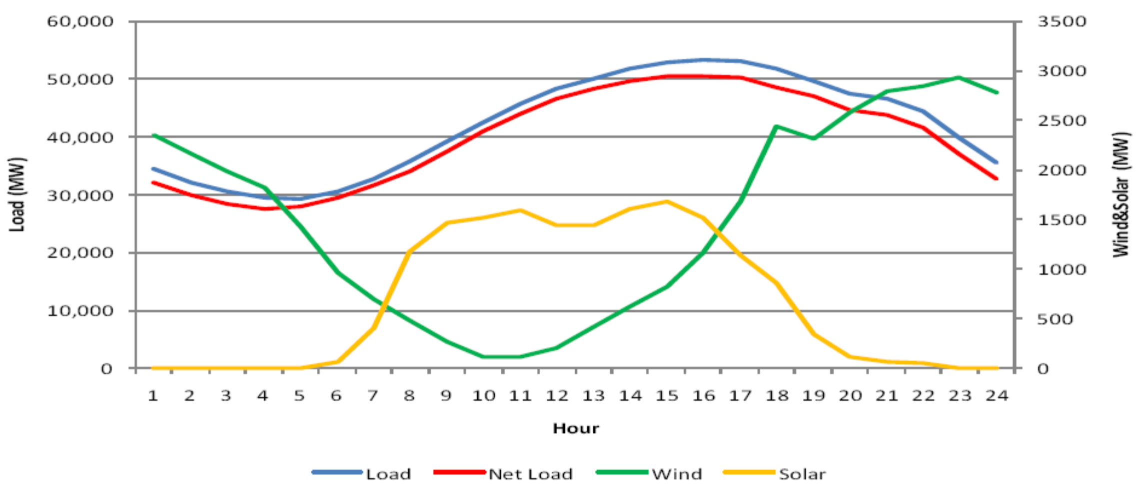


Figure 1-5: Simulated July 25, 2012

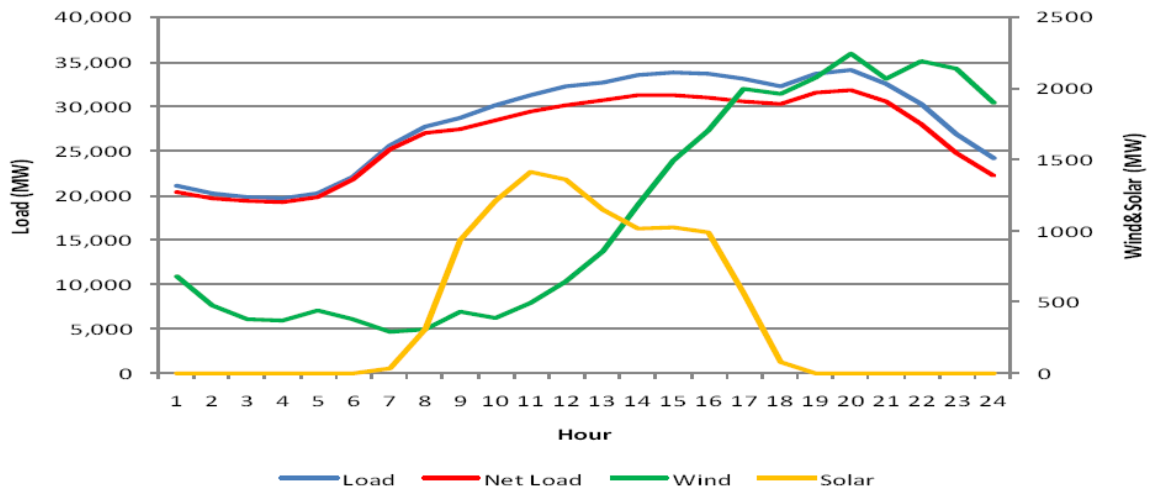


Figure 1-6: Simulated October 23, 2012

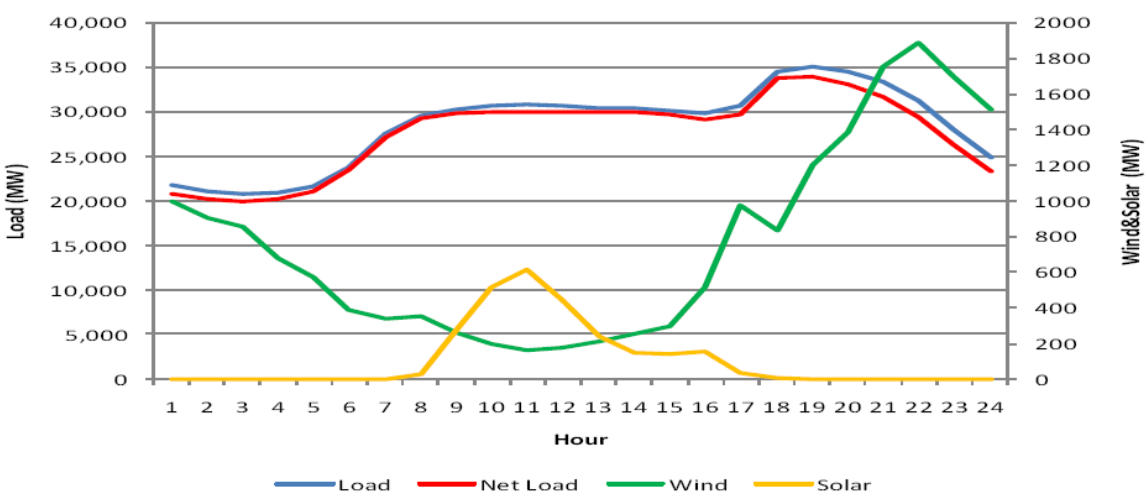


Figure 1-7: Simulated December 4, 2012

On the time-scale of multiple days, wind production will vary substantially across each day, regardless of the season. Figure 1-8 shows the daily wind pattern for May 2012 analyzed in this study. Each line of a different color represents a different day in the month. The monthly average hourly production shown by the thicker red line thus represents a wide range of actual daily production. Figures 1-9 to 1-12 show the dispersion of simulated wind production by operating hour in each season in 2012. These figures show that in almost every operating hour, wind could be producing across the full range of its potential production, from close to zero to almost maximum output.

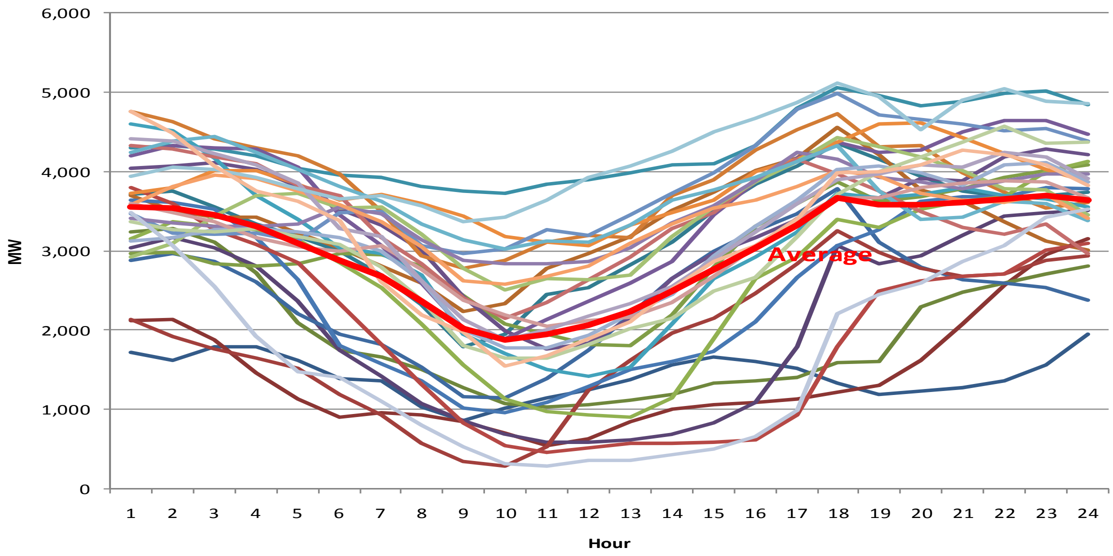


Figure 1-8: Wind Production in May 2012 based on 2005 production patterns

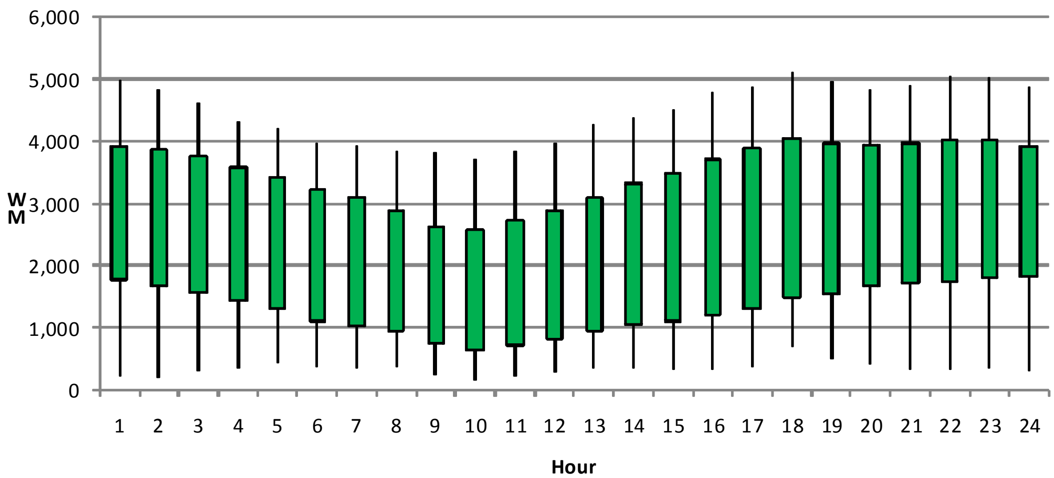


Figure 1-9: Spring 2012 Simulated Wind Production by Hour

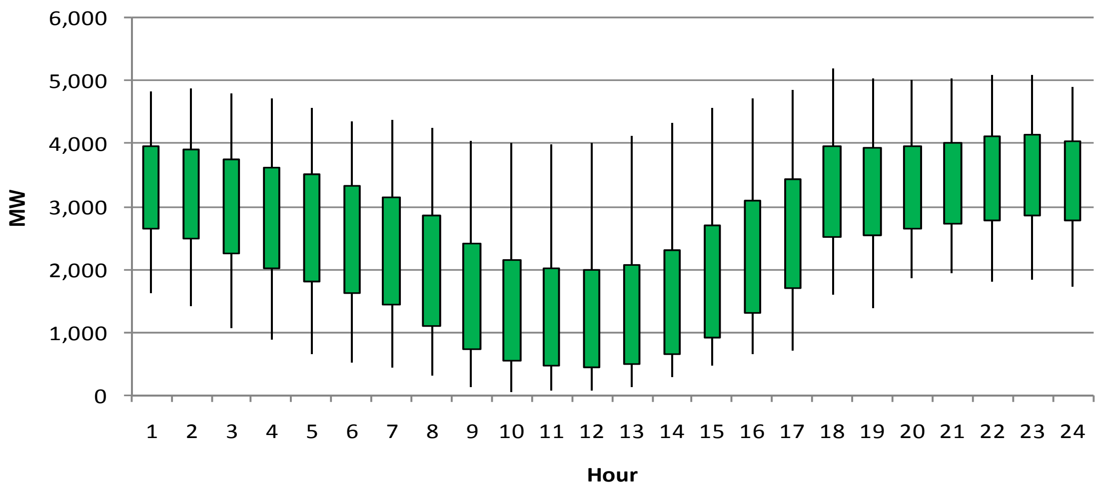


Figure 1-10: Summer 2012 Simulated Wind Production by Hour

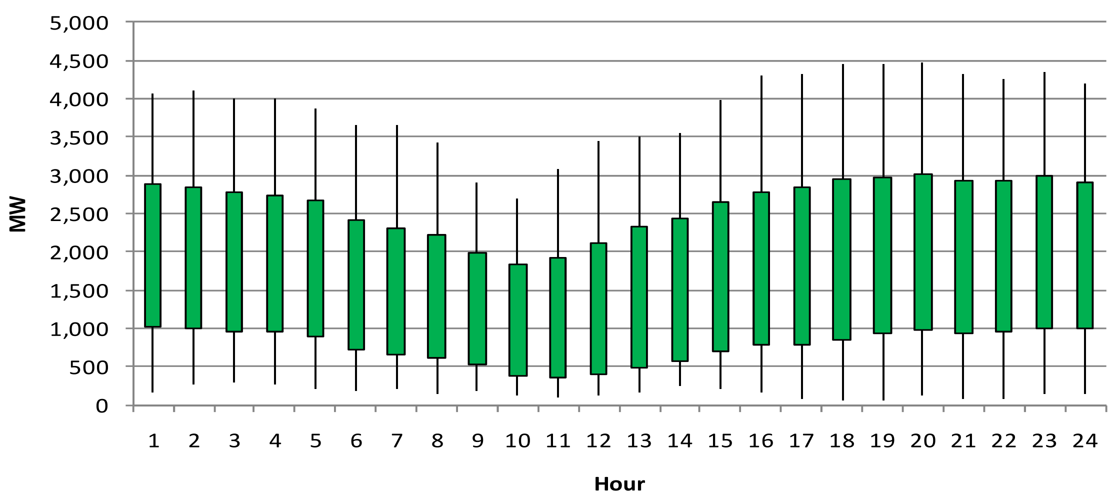


Figure 1-11: Fall 2012 Simulated Wind Production by Hour

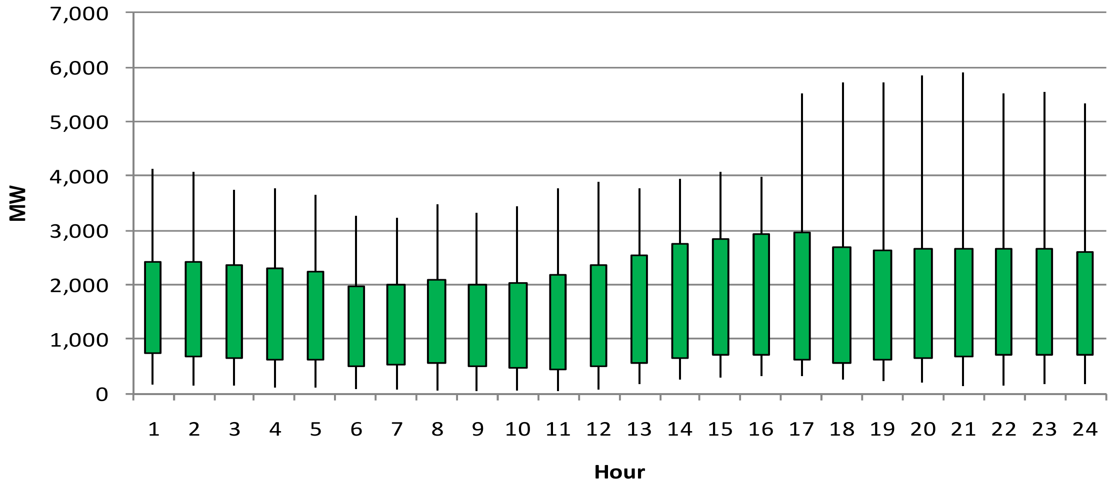


Figure 1-12: Winter 2012 Simulated Wind Production by Hour

Another important characteristic of wind generation is that it may operate at low capacity during peak hours, particularly the annual summer peak demands. Figure 1-13 shows wind generation production during the historical peak hours in the July 2006 heat wave. The red dots indicate peak hours, showing that average hourly production during those hours was close to the daily minimum wind production. Of note, 2006 is one of the benchmark years for the simulations in this study. In other years, there will be different patterns of summer peak hour wind energy production. For example, Figure 1-14 shows that in July 2010, wind production was higher during peak hours than in 2006, but still below maximum production, while Figure 1-15 shows that in August 2010, peak load production varied substantially.

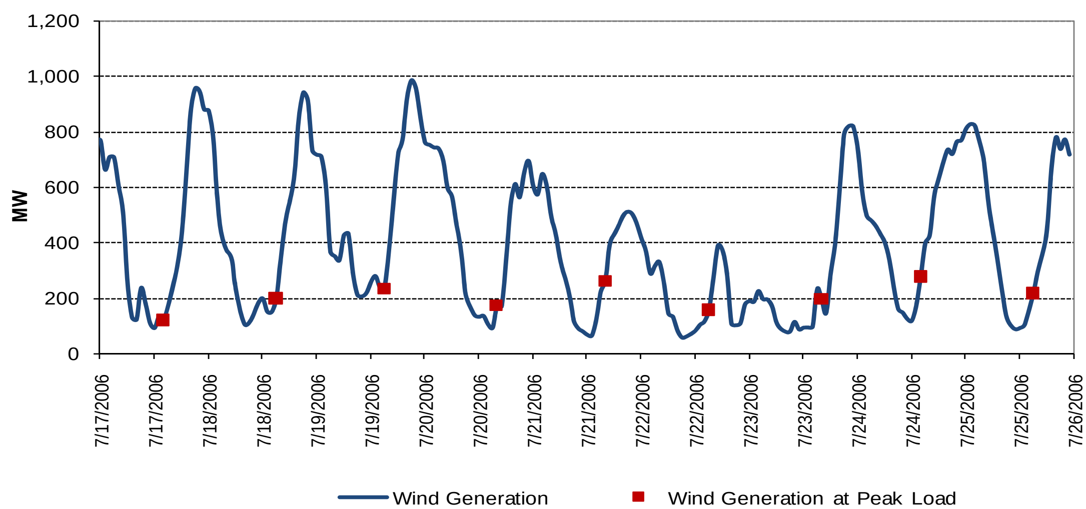


Figure 1-13: Wind Production during Summer Peak Hours in 2006

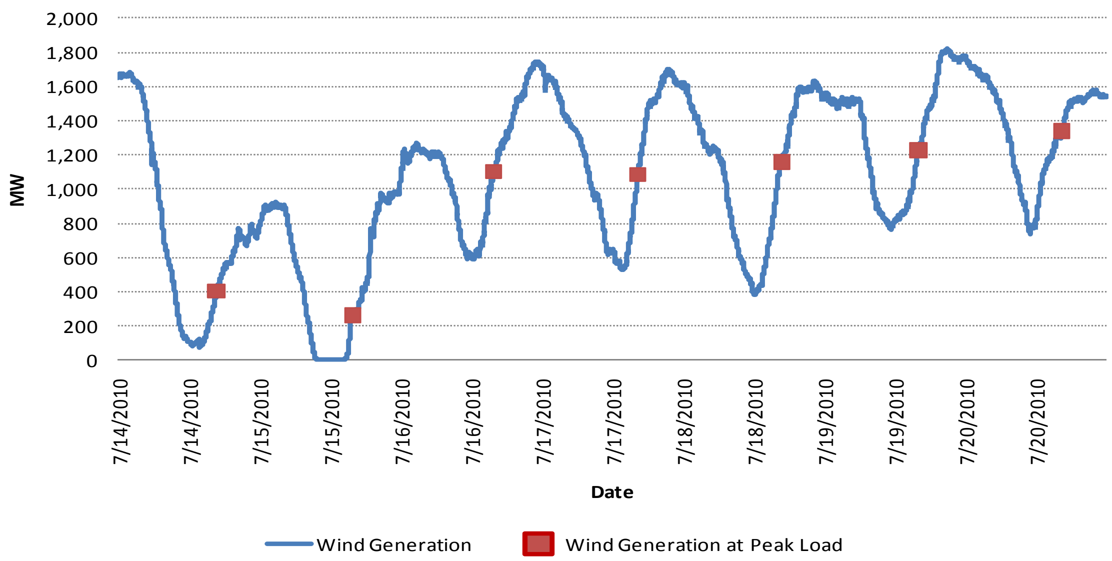


Figure 1-14: Wind Production during July Peak Hours in 2010

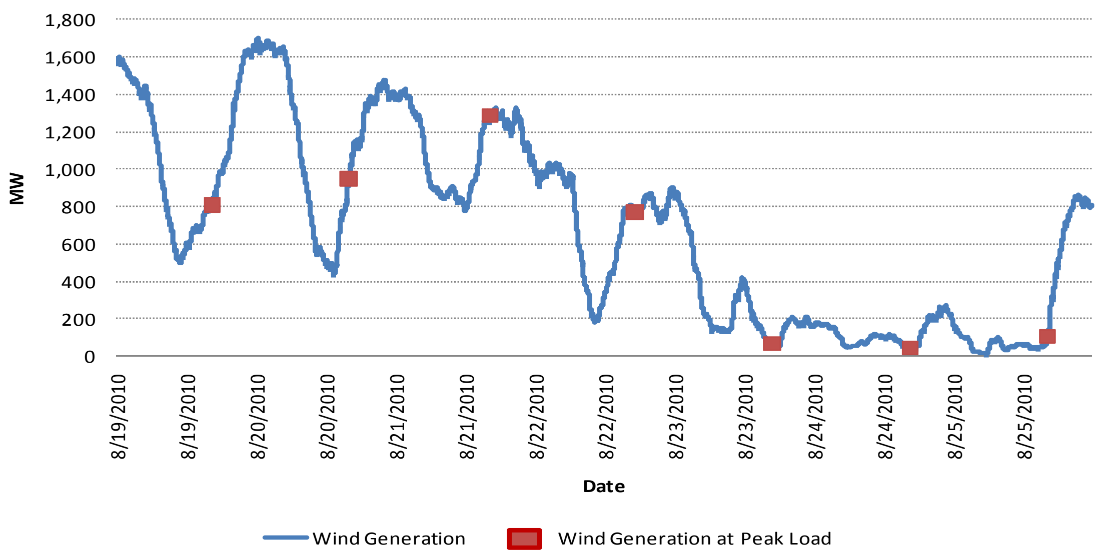


Figure 1-15: Wind Production during August Peak Hours in 2010

Even on the time-scale of months or seasons, when average production is measured, total wind generation can vary fairly substantially by hour and season. For much of the year, wind generation is on average inversely related to load, but in some seasons, notably spring, there can be a higher correlation on average between peak wind production and peak daily load.[23] Within any particular season, as noted above, the average wind

[23] As shown in Figure 2-1, in the spring months, the total wind generation on average starts decreasing after midnight and reaches its minimum production level around midday, just as the system experiences the first peak of the day. Beginning around Hour 13, the wind generation starts to increase while system load

production shown here does not reflect the significant differences in wind production on any particular day. Solar production is clearly well correlated with the daily load cycle, but seasonal weather patterns can result in different average solar generation. Moreover, in the winter, solar production can diminish before the daily peak hours.

1.3.2 Wind and Solar Forecast Uncertainty

The second important operational characteristic of variable energy resources is the uncertainty about their production, due to the current accuracy of weather forecasting, in particular of wind speed and cloud formations. Historically, given its variable nature, wind generation has been taken on an as-available (or "must take") basis, and grid operators compensate by incrementing or decrementing the output of other committed generation. At low wind penetrations, such actions do not significantly affect system operations. At higher levels of wind penetration, however, forecast uncertainty becomes more challenging. Figure 1-16 shows actual wind generation and the forecasted wind generation in the hour-ahead time frame.

Improvements in forecasts will facilitate renewable integration by allowing operators to ensure that the right resources are committed and on dispatch to address actual variability. The ISO is undertaking a number of initiatives to improve forecasting and the integration of forecasts into its market and system procedures.[24] This study does not focus on improvements in forecasts, but does conduct sensitivity analysis in the simulations to examine the impact of such improvements on operational requirements (see Appendix A-2).

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typically drops off. As system load increases towards the second peak of the day (which occurs in the spring), the pick-up in wind generation offsets some of the energy required to meet the increase in load. As system load begins dropping after the daily peak, wind is typically at its highest generation level. In the summer and fall months, average wind production peaks around Hour 24 and then decreases over the morning until reaching a minimum in the middle hours of the day, when load is at or close to its maximum. Wind production picks up in the early evening hours when load is typically decreasing. The winter months have a slightly different average pattern, in which average wind production is less variable over the day.

[24] The ISO aims to achieve continuous improvements as they become available by both public and commercial weather forecasting systems as well as innovative technology vendors (such as laser-based short-term wind forecast technologies). In this regard, during 2008-09, the ISO undertook an evaluation of three commercial wind forecasters that demonstrated improvements in both day-ahead and hour-ahead forecasts and examined the impact on wind forecast errors of geographic diversity of wind resources and different load levels, among other factors. The results are available in California ISO, *Revised Analysis of June 2008 – June 2009 Forecast Service Provider RFB Performance*, March 25, 2010, available at http://www.caiso.com/2765/2765e6ad327c0.pdf.

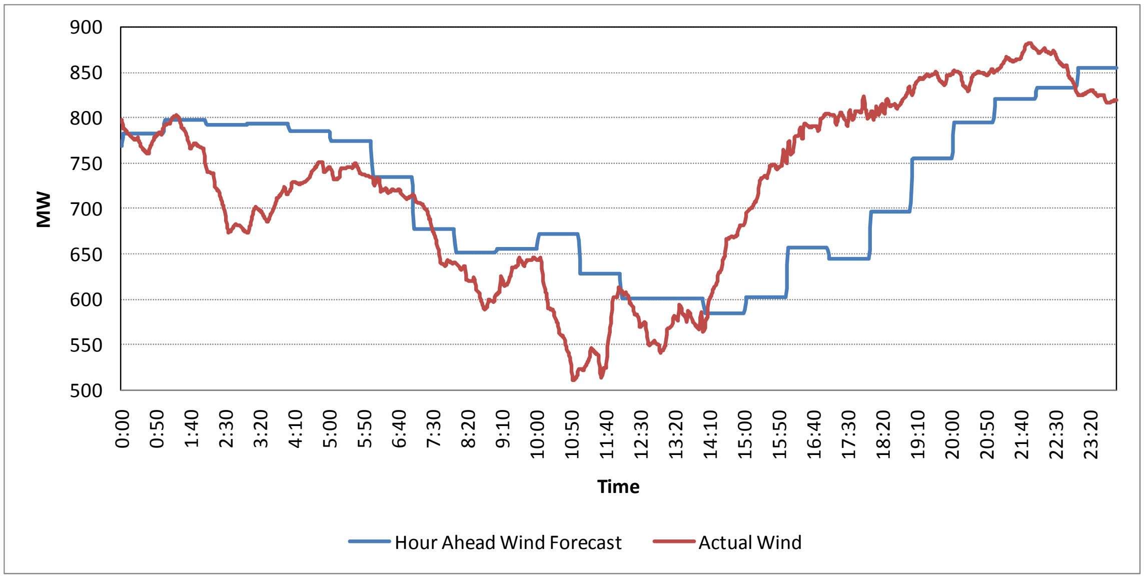

Figure 1-16: Hour-ahead forecast and actual generation profile for wind production, June 24, 2010

1.3.3 Impact of Variability and Uncertainty on Market and System Operations

Variable energy resources schedule and operate within the sequence of day-ahead to real-time market and system operational procedures that the ISO conducts on various intervals over the day. The ISO markets are a specialized type of wholesale commodity market in that any scheduling and trading must be consistent with: (a) the physical laws that govern power flows, (b) the need to balance the system second-by-second, and (c) physical and reliability constraints that affect the operation of both generation and transmission facilities—particularly the congestion and losses associated with transmission use. The ISO markets are in fact designed around reliable system operations, and the prices generated in those markets provide information relevant to future operational needs. More information on the markets and system operations can be found in the ISO's business practice manuals (BPMs), tariff, and other technical documents; this section focuses on a few key features applicable to renewable integration.[25]

Because generation resources have different start-up times (ranging from more than 24 hours for large steam units to under 10 minutes for gas turbines), system operators must begin the process of scheduling generation based on forecasts of next day system conditions. This is the function of the ISO day-ahead market, which takes place in the

[25] On market and system operations, see in particular the BPM for market instruments and the BPM for market operations. These are available at http://www.caiso.com/17ba/17baa8bc1ce20.html. More detail on the ISO's market and system operations and renewable integration can be found in the ISO's comments to the Federal Energy Regulatory Commission (FERC) in its recent notice of inquiry on variable energy resources, available here: http://www.caiso.com/2777/2777ac8636f20.pdf. In addition, the ISO will be undertaking a detailed review of market design changes needed to facilitate renewable integration, with documents and schedules provided here: http://www.caiso.com/27be/27beb7931d800.html.

afternoon of the day prior to the operating day. The day-ahead market consists of an integrated forward market that clears on the basis of schedules and market bids submitted by both suppliers and load. The integrated forward market is also where the ISO aims to procure one hundred percent of its ancillary service requirements for the next day, including regulation, spinning reserves and non-spinning reserves.[26] The ISO then makes adjustments to the day-ahead schedule using its own load forecasts and forecasts of renewable production in a process called the residual unit commitment. This sequence of markets and procedures is collectively called the day-ahead market.

Wind and solar resources can schedule voluntarily in the day-ahead market. However, there is currently little incentive for them to do so prior to the hour-ahead scheduling process, as discussed next. Moreover, day-ahead forecast errors for variable energy resources are not insignificant. From an operational perspective, the failure to schedule renewable resources day-ahead can result in additional commitment of conventional resources. In the event that the day-ahead market significantly underestimates the next day's renewable production, there could be situations in which the ISO has difficulty committing the right conventional units to provide integration capabilities in real-time.[27] The simulations described in Section 3 and Section 5 attempt to test for this outcome.

The day-ahead market schedules are in one-hour blocks; that is, there are no schedules for expected load or wind and solar production at intervals within the hour. When the operating day begins, the real-time market serves to adjust day-ahead schedules to account for imbalances, because of forecast error, changes in system conditions, actual intra-hourly load and renewable energy production, and any other factors. It does so through a sequence of procedures, including an hour-ahead scheduling process for changes to intertie schedules, rolling intra-hourly unit commitment procedures, and 5-minute economic dispatch intervals in which system operators send instructions to increment or decrement the output of generators under dispatch.

Scheduling of wind and solar resources under the ISO's Participating Intermittent Resource Program (PIRP) is conducted through a special process. Prior to the hour-

[26] Ancillary services are additional services provided by generation and, increasingly, non-generation resources, such as demand response and storage, that are needed for power system reliability. As discussed elsewhere in this report, ancillary service procurement may increase with additional renewables. Two types of ancillary services are procured by the ISO through the wholesale markets: operating reserves and regulation. Operating reserves are essentially capacity retained on generators that can be converted to energy in a short period of time in order to responds to contingencies such as the loss of a generating resource or a transmission line. There are two types of operating reserves in the ISO markets: ten-minute spinning reserves, provided by resources that are synchronized to the grid, and ten-minute non-spinning reserves, provided by resources that are not synchronized but can start and provide energy within ten minutes. Regulation is energy provided on a second-by-second basis for system balancing by resources equipped with automatic controls. Currently provided by thermal generators and hydro systems, regulation could be supplied also by demand response and storage technologies. The ISO also meets other ancillary services requirements that are not procured through the markets, such as voltage support and black-start.

[27] If the integrated forward market fails to forecast renewable energy production adequately, the ISO can also adjust its residual unit commitment to account for forecast renewable production. However, as this residual unit commitment takes place day-ahead, it is also subject to forecast errors.

ahead scheduling process, data is collected from wind resources and transferred to a forecast service provider, which develops an hour-ahead wind forecast. This forecast is then returned to the ISO via the scheduling coordinators for the participating resources. Deviations from the hour-ahead schedules are followed by the ISO's dispatch functions (every five minutes) and regulation (second-by-second) in real-time. Resources in the PIRP are settled financially using a formula that nets their imbalances over the month and applies an averaged monthly locational marginal price for energy. Generally, because of their contracts, production incentives, and technology, wind and solar resources do not respond to price-based dispatch instructions, but only to reliability-based dispatches when they are needed to decrement output to address congestion or overgeneration. If such resources become more price-responsive, they could reduce the ISO's need for additional operational capabilities discussed in this report.

1.3.3.1 Impact on Load-following and Regulation

To further explore the operational and market impact of variability and forecast uncertainty in real-time requires additional detail on how the ISO markets follow load and renewable resource schedule deviations over the operating hour. Secondary frequency control mechanisms such as load-following and regulation are the key mechanisms by which the ISO maintains the balance between generation and load in the time frame of seconds to minutes.

The demand and generation are constantly changing within the ISO balancing authority area (BAA). This means that the ISO will have some unintentional outflow or inflow of energy at any given instant. The mismatch in meeting a balancing authority's internal obligations, along with a small obligation to maintain frequency, is measured via an instantaneous value called Area Control Error (ACE), measured in MW. The North American Electric Reliability Corporation (NERC) control performance standards are intended to be the indicator of sufficiency of secondary control. Overgeneration makes ACE go positive and the frequency increases. A large negative ACE causes frequency to drop. NERC Control Performance Standards (CPS1 and CPS2) capture these relationships. In simple terms, CPS1 assigns each balancing area a slice of the responsibility for control of the interconnection frequency. The amount of responsibility is directly related to the size of the BAA. CPS2 is a statistical measure of ACE over all 10-minute periods in a month. Under CPS2, ACE is limited to a regulating range whose width is proportional to the BAA's size.

The ISO monitors ACE and attempts to keep the value within specified limits. This is accomplished through a combination of automatic generator adjustments, manual dispatch and sales and purchases from neighboring balancing authorities. The ISO maintains sufficient generating capacity, both in the up and down direction, under automatic generation control (AGC) within the energy management systems (EMS) to continuously balance generation and interchange schedules with real time load.[28] Although the regulation dispatch is done every four seconds, the regulation margin has to

[28] The WECC defines AGC as equipment that automatically adjusts a control area's generation from a central location to maintain its interchange schedule plus frequency bias.

be adequate to meet deviations within a 5-minute dispatch interval. The capacity under AGC is referred to as regulating reserve or regulation.[29] Figure 1-17 pictorially depicts the regulation capacity requirement—that is, the MW range that regulating resources must be able to provide—as the area shaded in red: the area between actual load and the 5-minute dispatch.

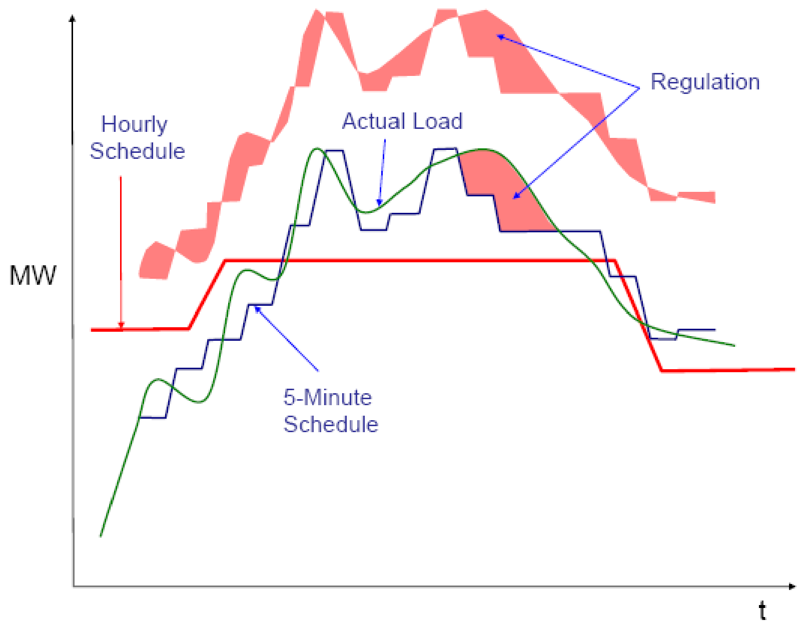

Figure 1-17: Regulation Requirement shown as the red shaded area

Load-following is the use of online generation on economic dispatch or quick start generation to meet the intra- and inter-hour changes in loads. While regulation is needed to balance the minute-by-minute changes in the system and keep ACE with limits, load-following is required to ensure that the system has enough capacity on economic dispatch to move from one 5-minute dispatch interval to the next. Load-following is not an ancillary service like regulation and is not explicitly procured by the ISO in its day-ahead and real-time markets; rather, it is a function of the generation committed and dispatched in the day-ahead to real-time market and operational sequence and is met as long as the optimization algorithms used in those processes are appropriately specified. Similar to regulation, load-following is defined in both the up and down directions.

In this study, several measures of load-following requirements are presented, including capacity and ramps over various time frames needed to fill the gap between the difference between the day-ahead hourly schedule for an operating hour and the real-time 5-minute dispatch schedule. In Figure 1-18, load-following capacity—that is, the incremental and decremental energy that resources on economic dispatch have to be able to provide

[29] The WECC defines Regulating Reserve as sufficient spinning reserve, immediately responsive to automatic generation control (AGC) to provide sufficient regulating margin to allow the control area to meet NERC's Control Performance Criteria.

within the operating hour to meet load—is depicted graphically as the blue shaded area. Load-following ramp rate, expressed in MW/min, is the rate at which this capacity can ramp from one 5-minute dispatch point to the next.

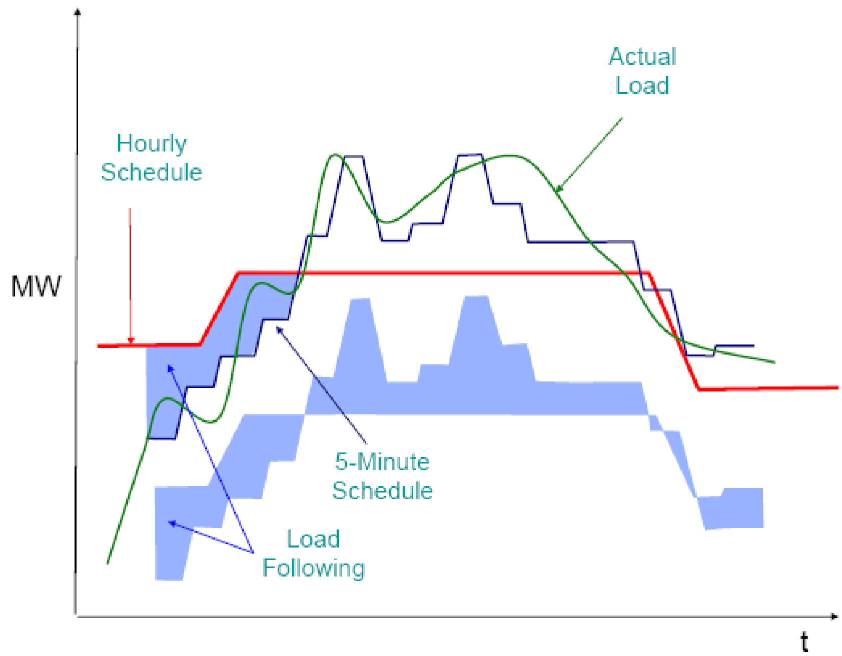

Figure 1-18: Depiction of hourly load-following capacity requirement

As seen in Figure 1-2 and Figure 1-3, wind and solar generation vary on a minute-by-minute basis. The variability in wind and solar generation, coupled with the variability in load, will have an impact both on regulation and load-following requirements. The uncertainty in wind and solar generation increases the system operator's need to reserve capacity for wider ranges of regulation and load-following capability than would otherwise be needed if they had full certainty about the actual variability. Uncertainty in the day-ahead timeframe may lead to a unit commitment with inadequate regulation and load-following capability that is required in real-time. The lack of regulation and load-following capability may have an impact on ACE, and if sustained, result in a CPS2 violation. Under extreme cases, the lack of regulation and load-following down capability might require the curtailment of generation to keep ACE within specified limits.

1.3.4 Overgeneration due to Variable Energy Resources

Overgeneration occurs whenever there is more generation than load and the operators cannot move generators to a lower level of production. In California, overgeneration is most likely to occur under the confluence of some or all of the following conditions: light spring load conditions (historically with loads around 22,000 MW or less), all the nuclear plants on-line and at maximum production, hydro generation at high production levels due to snow melt in the mountains, long-start thermal units on-line and operating at their minimum levels because they are required for future operating hours, other generation in a regulatory "must take" status or required to be on-line for local reliability reasons, and wind generation at high production levels. At higher levels of RPS, solar production may also be a factor in overgeneration conditions, particularly in the morning solar ramp hours.

All other things equal, the increased generation from variable energy resources under a 20 percent RPS is expected to lead to higher frequency and magnitude of overgeneration conditions than exist today. Even if renewable resources were perfectly predictable and constant (i.e., no uncertainty and variability in generation), the amount of wind and solar generation that can be accommodated into the system will depend on the extent to which the existing fleet can be dispatched downwards to accommodate the renewable energy. Inability to dispatch the existing fleet will lead to overgeneration conditions and could possibly result in the curtailment of renewable generation.

To illustrate overgeneration conditions, Figure 1-19 shows the load for one week (red trace) and the generation from non-dispatchable resources. Non-dispatchable resources in this figure include the following generation resources: nuclear, biomass, geothermal, Qualifying Facilities (QFs), hydro and imports. Non-dispatchable resources also include wind and solar generation. Some of the resources are dispatchable, but a portion of their generation is treated as fixed due to contractual and other reasons. During some periods, the total generation from the non-dispatchable resources approaches the load that needs to be served. These periods will likely see overgeneration, especially if thermal generation needs to be dispatched at their minimum operating level. Importantly, overgeneration in this case has very little to do with the variability and uncertainty of generation from variable energy resources. Rather, it strictly depends on whether the rest of the fleet can be dispatched down to accommodate the energy from variable energy resources.

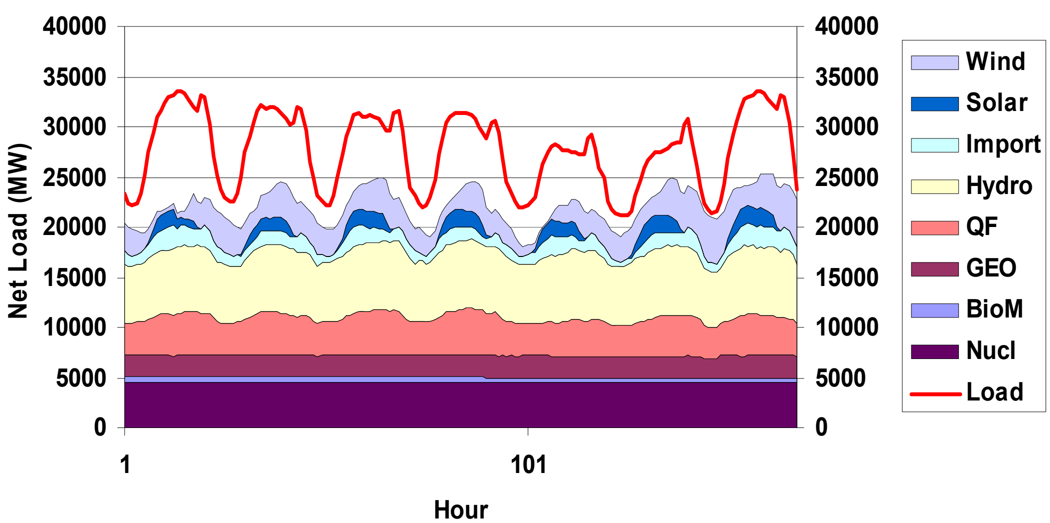

Figure 1-19: Load and Non-dispatchable generation for one week

1.4 Objectives of this Study

The ISO and California state agencies have undertaken several analyses that attempt to estimate the requirements on the power system to integrate higher levels of variable energy resources, including the ISO's 2007 Report.[30] The 2007 Report concluded provisionally that integrating 20 percent renewable energy into the California electric power system is operationally feasible, subject to changes to operating practices. Based on a high-level survey of existing resources, the report also concluded that ISO generation and pumped storage was adequately flexible to meet the anticipated ramping requirements for load-following and regulation. The report noted the potential for renewable energy to cause an increase in overgeneration conditions, but did not attempt to quantify that increase.

This study addresses some of the recommendations of the 2007 Report and fills some of the gaps in the prior analysis. Because that report focused only on the impact of wind generation on system operations, one of its recommendations was for a future study to analyze the impact on integration requirements of solar power variability and forecast error. Another recommendation was to study changes in the commitment and dispatch of thermal resources due to renewable integration, in particular to quantify the impact of additional cycling (additional start-ups) and associated wear-and tear on conventional generation. This study addresses these recommendations and undertakes other analysis. Other recommendations are being addressed through various other ISO operational and market initiatives.

The starting point for the present analysis is that while there is substantial interest in storage and demand response to provide integration capabilities, at least during the next few years, support for integration of renewable resources during normal operating conditions will need to be provided largely through the flexibility of existing, re-powered, and new thermal generation. This generation fleet will also need to have the ability to provide sufficient ancillary services, particularly regulation up and regulation down and possibly some additional operating reserves.

Given this background, this study focuses on the operational requirements and assessment of generation fleet capability, along with measurement of generator operations and economic impacts, under the most recent estimate of the conventional and renewable resource mix under a 20 percent RPS. The core objectives of the present study are:

- to forecast the operational requirements and extreme conditions—specifically operational ramps, load-following, regulation, and overgeneration—under a 20 percent RPS that includes over 2000 MW of solar;

[30] California Energy Commission, "Intermittency Analysis Project" (2007), CEC-500-2007-081 at http://www.energy.ca.gov/2007publications/CEC-500-2007-081/CEC-500-2007-081.PDF; California ISO, *Integration of Renewable Resources – Transmission and Operating Issues and Recommendations for Integrating Renewable Resources on the ISO-Controlled Grid*; KEMA, *Research Evaluation of Wind Generation, Solar Generation, and Storage Impact on the California Grid*.

- to further assess and verify—through analysis of historical operational data, as well as simulations of future conditions—that the existing fleet is sufficiently capable of satisfying the forecasted system operational requirements; and

- to provide insight on expected changes to generation fleet operations and market revenues.

The analysis and conclusions presented here will be augmented by the ISO's forthcoming scenario-based 33 percent RPS operational and market study, which is similar in structure and methodology to this study. As the renewable portfolios in 2020 and interim years become better defined, the ISO will also extend this analysis to renewable cases between 20 percent and 33 percent RPS.

2 Study Methodology and Assumptions

To provide the level of detail on operational requirements and capabilities needed to enable adequate system and market preparations, the ISO has worked intensively, including through collaboration with a number of organizations, to develop a suite of simulation models and to conduct extensive analysis of empirical data. A further objective is to standardize elements of these analyses to support periodic updating of the results as the mix and location of future renewable resource portfolios changes. This study utilizes several of these analytical methods to assess both the operational requirements associated with renewable integration and the capability of the generation fleet to meet those requirements.

The study evaluates a subset of key *operational requirements* that include (1) operational ramp rates at different time scales, (2) regulation capacity and ramp rate, and (3) load-following up and down capacity and ramp rates. These requirements are estimated using a statistical simulation methodology initially developed for the ISO's 2007 Report; for this study, that methodology has been updated to evaluate the impact of solar production forecast error and variability on these requirements.

Operational capability refers to the ability of the ISO's existing and planned generation and non-generation resources to address the incremental operational requirements as a result of variable energy resources. For this study, operational capabilities were evaluated on two separate tracks:

- First, the ISO reviewed data on the certified operational characteristics of the existing generation and pumped storage resources to gain insight into capacity with different ranges of start-up times, ramp rates and regulation capacity and ramp rates. The ISO also analyzed historical operational and market data to evaluate what additional operational flexibility might be available in current operations to accommodate renewable integration (i.e., without requiring changes to market operations or procurement of additional reserves).

- Second, the ISO has used both deterministic and stochastic production simulations to estimate whether the generation fleet possesses the capability to meet load in both hourly and sub-hourly time frames and supply the required ancillary services, under 20 percent RPS.

This section is organized as follows. Common data and assumptions for the simulations are described first, along with some further characterization of net load in 2012. The statistical methodology used for determining the regulation and load-following requirements is described generally in Section 2.4. The production simulation methodology and description of data and assumptions specific to those simulations are provided in Section 2.5.

2.1 Study Scenario Data and Assumptions

This section describes the common assumptions and data used in development of the scenarios for 20 percent RPS.

2.1.1 Load

As noted, the year 2012 was selected as the target year for the 20 percent RPS. The load profiles for 2012 were developed by scaling actual 1-minute ISO Balancing Area load data from two base years – 2006 and 2007 – using an annual load growth factor of 1.5 percent. The years 2006 and 2007 were selected to permit an assessment of the effects on fleet capability under distinct hydro conditions, with 2006 being a high-hydro year and 2007 being a low-hydro year. The use of base year 2006 is further consistent with the decision to apply conservative, i.e., stressful, assumptions in the analysis whenever appropriate since 2006 represents a greater than average ISO coincident peak load condition.

The application of a linear annual load growth factor of 1.5 percent from 2006 and 2007 may result in an overestimate of demand and peak in 2012 when compared against the California Energy Commission's (CEC) revised 2012 forecast included in its December 2009 California Energy Demand Forecast 2010-2020.[31] Table 2.1 sets forth the annual net energy and the coincident peak growth rates assumed by the CEC for the ISO Balancing Areas for the 2009 revised forecast, which reflected the impact of reduced economic activity during 2008-2010 and from a prior 2007 forecast. Table 2.2 reflects the load data used in the study and includes a comparison to both the prior 2007 CEC demand forecast and the revised 2009 CEC estimate. The total demand used in the study for 2012 (2006 base year) is approximately 10 percent greater than the CEC's current estimate of 2012 demand, while the non-coincident peak load for 2012 (2006 base year) is approximately 5 percent higher than currently anticipated by the CEC. However, in order to assess the impact of the potential additional load, the ISO has performed production simulations based on 2006 demand without the 1.5 percent annual load growth factor. The demand in this sensitivity exceeds the 2009 CEC demand forecast by approximately 2 percent.

The use of the higher demand assumption is consistent with study's primary objective of assessing the capability of the thermal generation fleet to reliably integrate a 20 percent RPS renewable resource portfolio. The effect of potentially overestimating demand is to more severely test the ability of the existing generation fleet to account for both greater than average load conditions and the integration of a concomitantly higher level of renewable resources (adjusted to meet the 20 percent RPS at the higher load). Relatively higher levels of renewable resources will increase the overall system variability and uncertainty and need for operational flexibility.

[31] See CEC, California Energy Demand 2010-2020 Adopted Forecast available at http://www.energy.ca.gov/2009publications/CEC-200-2009-012/CEC-200-2009-012-CMF.PDF.

Table 2.1: CEC Average Annual Net Energy[32] and Average Peak Growth Rates[33]

Year	Annual Average Net Energy		Average Annual Peak Growth Rates	
	CEC Forecast 2007 – Statewide	CEC Forecast 2009 – ISO Balancing Area	CEC 2007 Forecast – Statewide	CEC 2009 Forecast – ISO Balancing Area
2008 – 2010	1.39 percent	-0.99 percent	1.43 percent	0.82 percent
2011 – 2015	1.21 percent	1.22 percent	1.31 percent	1.50 percent
Avg.	1.28 percent	0.39 percent	1.36 percent	1.25 percent

Table 2.2: Demand Assumptions in 2012[34]

Service Territory		Base Year 2006	Base Year 2007	CEC 2007 Forecast	CEC 2009 Forecast Adopted
PG&E	Base Year Energy (GWh)	107143	108290		
	Base Year Peak (MW)	22635	21196		
	2012 Energy (GWh)	117155	116659	113238	111113
	2012 Peak (MW)	24750	22834	24699	24112
SCE	Base Year Energy (GWh)	111560	112507		
	Base Year Peak (MW)	23340	23830		
	2012 Energy (GWh)	121985	121202	111562	102408
	2012 Peak (MW)	25521	25672	24805	23522
SDG&E	Base Year Energy (GWh)	21498	21513		
	Base Year Peak (MW)	4476	4602		
	2012 Energy (GWh)	23507	23176	22606	21682
	2012 Peak (MW)	4894	4958	4842	4640
ISO Total	Base Year Energy (GWh)	240201	242310		
	Base Year Peak (MW)	50451	49628		
	2012 Energy (GWh)	262646	261037	247406	235203
	2012 Peak (MW)	55165	53463	54346	52274
Note:	Total Peaks are non-coincident				

32 *Id.* at P. 13 (Table 3) and 16 (Table 4).

33 *Id.* at P. 13 (Table 3) and 20 (Table 5), Statewide peak growth rates apply to a non-coincident peak, while the ISO annual peak growth rates apply to a coincident peak.

34 *Id.* at P. 55 (Table 10), 89 (Table 14) and 123 (Table 18),

2.1.2 Renewable Resource Portfolios by Capacity

The study models two renewable resource portfolios:

- a "20 percent RPS" portfolio that models 20 percent renewable energy in 2012 based on data developed by the California Public Utility Commission (CPUC); and

- a "2006 Reference" portfolio which includes only renewable resources on-line in 2006 to provide a reference to the 20 percent RPS results.

In both cases, the remainder of the generation fleet consists of resources that were on-line through 2006 within the ISO's footprint and the addition of 3,263 MW of new thermal generation facilities expected to be on-line by 2012.

The 20 percent RPS portfolio being modeled has some significant differences from the one modeled in the 2007 Report. In 2006, when the prior study assumptions were developed, the prevailing view based on Load Serving Entity (LSE) contracts and ISO generation interconnection queue positions was that wind would constitute the predominant incremental in-state renewable technology to achieve 20 percent RPS. Wind resource capacity *additions* consisted of a total of 4,040 MW: 3,540 MW located at Tehachapi and 500 MW located at Solano. Although the 2007 Report also assumed a significant amount of new geothermal and biomass resources, it noted that those types of resources are not variable and hence their integration into the ISO is not anticipated to cause material operational issues. Moreover, the 2007 Report assumed that the interconnection of less than 1000 MW of central station solar power by 2010, as estimated at the time, would not result in significant integration requirements. As a result, the analysis of operational requirements in the 2007 Report focused exclusively on the impact of wind resources.

Since 2007, solar projects have become a significantly higher percentage of the portfolio of renewable resources under contract with investor owned utilities as well as of those supply resources generally seeking to interconnect by 2012. Much of the anticipated solar capacity consists of photovoltaic (PV) technologies that have demonstrated substantial variability due to their potential for rapid fluctuations in output.[35] Hence, the ISO determined to examine more explicitly the impact of solar resources on the statistical analysis of operational requirements, as well as in the production simulations. The solar resources are modeled in Barstow, Riverside East 1, Riverside East 2, Mountain Pass/Tehachapi, and include some distributed generation at multiple locations.

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[35] E.g., as noted by NERC, "PV systems can experience variations in output of +/- 50 percent in the 30 to 90 second time frame and +/- 70 percent in a five to ten minute time frame. Furthermore, the ramps of this magnitude can be experienced many times in a single day during certain weather conditions. This phenomenon has been observed on some of the largest PV arrays (ranging from 3-10 MW) deployed in the U.S. located in Arizona and Nevada." See NERC, "Special Report: Accommodating High Levels of Variable Generation" at p. 27, available at http://www.nerc.com/files/IVGTF_Report_041609.pdf.

To provide a reference for changes on the power system, the ISO also modeled a "2006 Reference" scenario in which only renewable resources in operation in 2006 are considered in the simulations. This case is analyzed to measure the incremental impact of renewables in the production simulation. In the statistical analysis of operational requirements, this 2006 scenario is also modeled using 2006 loads to show the increase in requirements arising from the change in load from 2006 to 2012. Table 2.3 summarizes the installed capacity (MW) in each of the scenarios, including both renewable and conventional generation technologies.

Table 2.3: Installed Capacity (MW) of the 2012 Cases by Generation Type

	2006 Reference Case	2012 20 Percent RPS Case
Biomass/BioGas	701	701
Solar	420	2,246
Geothermal	1,101	2,341
Small Hydro	614	614
Wind	2,648	6,688
Total ISO Installed Renewable Capacity	5,484	12,590
Thermal	32,308	32,308
Large Hydro	7,166	7,166
QF	3,555	3,555
Nuclear	4,550	4,550
Total ISO Installed Conventional Capacity	47,579	47,579
Total ISO Installed Capacity	53,063	60,169
ISO Planning Reserve 17 Percent	64,543	64,543
Import Contribution to Capacity	12,711	12,711
Total Resources	65,774	72,880

The incremental renewable portfolio used in the study is intended to be consistent with assumptions made by state agencies and, in particular, the CPUC on the resource mix by technology and location (including in-state and out-of-state). As such, the expected wind capacity remains essentially the same as in 2007 Report, but the incremental geothermal and solar capacity is patterned after the 20 percent RPS reference case developed by the CPUC as part of its 33 percent RPS Implementation Analysis conducted in 2009.[36]

[36] See, CPUC, 33 percent Renewables Portfolio Standard, Implementation Analysis, Preliminary Results (June 2009), available at http://www.cpuc.ca.gov/NR/rdonlyres/1865C207-FEB5-43CF-99EB-A212B78467F6/0/33PercentRPSImplementationAnalysisInterimReport.pdf.

2.1.3 Aggregate Energy Production by Renewable Resources

The renewable resource capacity (MW) requirements shown above are determined by a combination of specific projects and the renewable energy requirements under 20 percent RPS. In turn, the total annual energy production by resource type is then converted into energy production profiles, based on the capacity factors of each technology by location, for each time interval being analyzed. Table 2.4 shows the annual energy production (GWh) associated with the mix of renewable resource capacity shown in Table 2.3.

Table 2.4: Renewable Energy Production (GWh) in the 20 percent RPS Scenario

Resources	Energy (GWh)
Wind (ISO)	17,886
Solar	4,907
Small Hydro	1,047
Biomass/Biogas	4,753
Geothermal	19,225
Wind (Out-of-State)	6,062
Total Renewable Resources	53,879
Total of All Resources	263,646
Renewables as a percentage of total resources	***20.4 %***

2.2 Development of Wind and Solar Production Profiles

The study uses a wind production profile for 2012 that was developed by AWS Truepower for the 2007 Report[37] and which located the incremental wind additions at Tehachapi and Solano. The expected wind production data was simulated using actual production data from January 2002 to December 2004 combined with atmospheric simulation models to create wind speeds for the resource areas. The maximum wind production level in the data set is 6,000 MW at times. Additional information on the development of the wind production data can be found in the technical appendix.

For both solar thermal and solar PV resources, production profiles by plant were also developed and were located at five CREZs and some distributed locations. A method

[37] This data was also used in the CEC IAP Study (http://www.energy.ca.gov/2007publications/CEC-500-2007-081/CEC-500-2007-081.PDF).

was developed to simulate locational variability in production due to changes in irradiance and the operating characteristics of each technology type.[38]

The final wind and solar production profiles used in the "2006 Reference" case and "20 Percent RPS" case were developed on a 1-minute time-step, corresponding chronologically to the load data for each period studied. Similarly to the graphs shown in Figure 1-2 and Figure 1-3 in Section 1, these profiles reflect the inherent variability of the wind and solar production for the target year (as well as load variability). Figures 1-9 through 1-12 in Section 1 plot the average hourly 2012 production data for wind in each season by operating hour.

2.3 Load Net of Renewable Energy by Season in 2012

Because both the renewable energy profiles and the load are fixed inputs into the models, the net load in each hour – load minus renewable energy production – can be calculated ex ante. This section shows the net load by season in 2012 as background to some of the subsequent simulation results.

Figure 2-1 toFigure 2-4 illustrate the *average hourly* load, net load and wind and solar generation in California for each of the four seasons in 2012 (as noted in Section 1, the average hourly production is not reflective of the actual hourly variability of wind and solar resources).[39] Load and net load MW are measured on the left horizontal axis (or y-axis), while wind and solar generation are measured on the right horizontal axis (or y-axis). The figures show that due to solar production, the net load now decreases in the daily peak hours in all seasons. This results in more displacement of daily peak hour thermal generation than the incremental wind-only scenario modeled in the 2007 Report. Section 5 discusses the exact energy displacement (GWh) by season as well as price and revenue impacts.

[38] The existing solar resources were modeled using ISO 1 minute production data. For the new plants, a different production profile data set was constructed for each technology type – solar PV with tracking, solar PV without tracking and solar thermal which used the trough model – at each location that captured differences in hourly solar irradiance, the time delay in how particular technologies respond to irradiance, and the effect of cloud cover on locations with multiple plants. The methodology is explained in detail in the technical appendix.

[39] That is, the hourly average production across all similar hours in the season using the data sets for the production profiles in the simulation models discussed in Sections 2-5. The averaging is why wind production appears much lower than its full rated capacity in 2012.

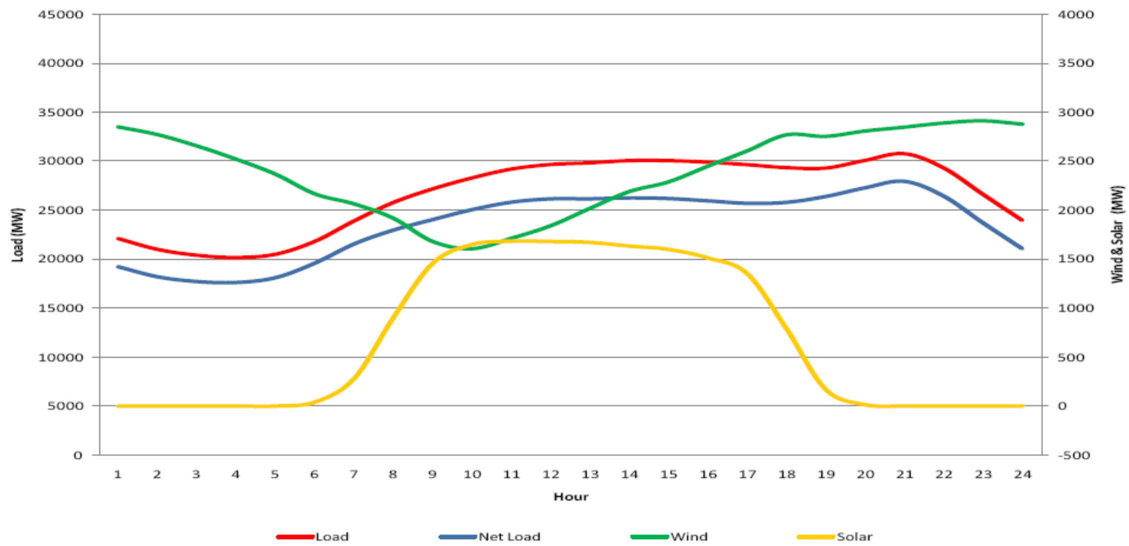

Figure 2-1: Simulated average hourly load, net load and wind and solar generation, Spring 2012

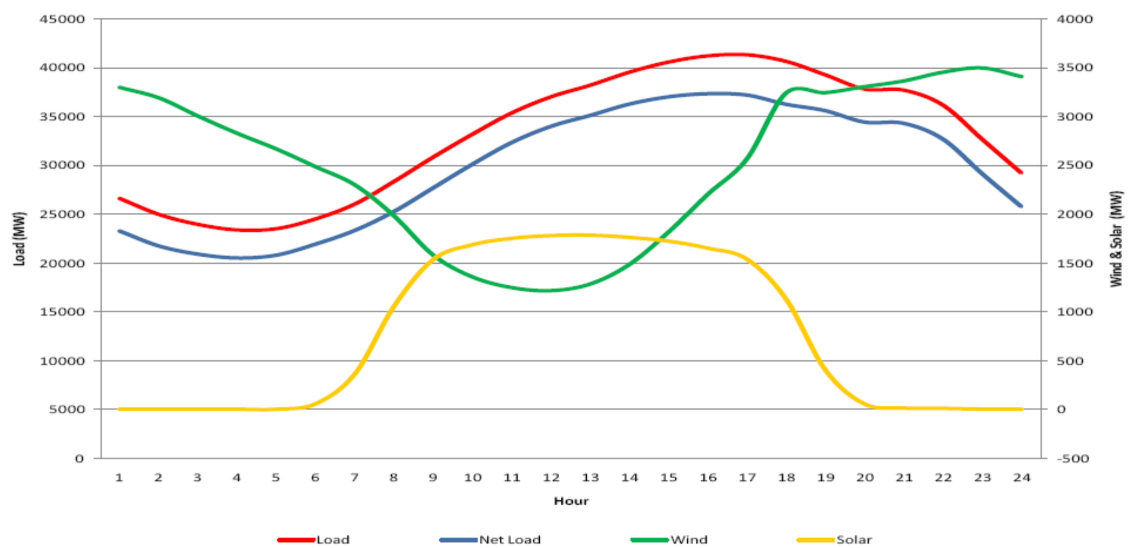

Figure 2-2: Simulated average hourly load, net load and wind and solar generation, Summer 2012

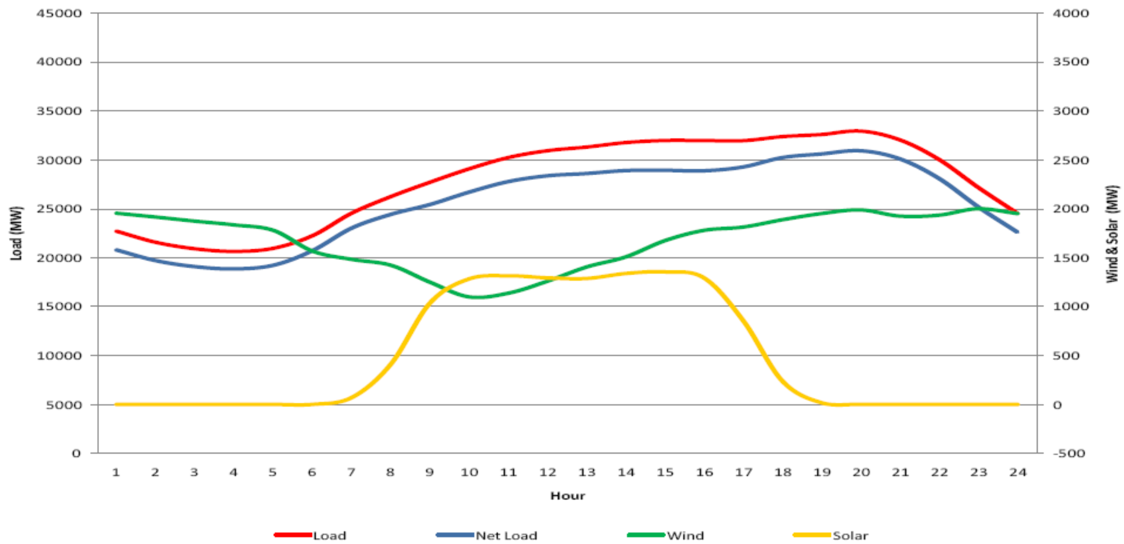

Figure 2-3: Simulated average hourly load, net load and wind and solar generation, Fall 2012

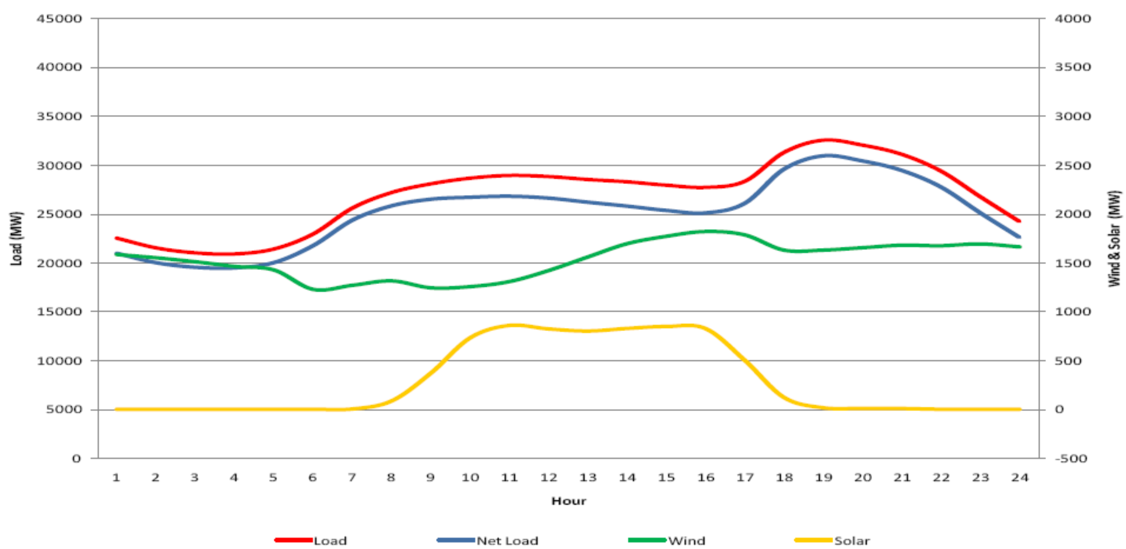

Figure 2-4: Simulated average hourly load, net load and wind and solar generation, Winter 2012

2.4 Methodology for Determining Operational Requirements

A key component of renewable integration studies is statistical analysis, including simulation through stochastic processes, of the potential deviations in wind and solar generation over various operational and market time frames – e.g., day-ahead to hour-ahead; hour-ahead to 5-minute; 5-minute to one-minute – due both to variability and forecast error. These deviations are measured in terms of operational ramping (various time frames), load-following capacity (typically deviations within the operating hour on a 5-minute basis) and regulation capacity (typically deviations from 5-minute schedules to

1-minute actual generation), and can then be evaluated against the operating characteristics and capabilities of system resources, as discussed in subsequent sections. This section begins with an overview of the statistical methodology used in this study, followed by more detailed discussion of how the regulation and load-following requirements are calculated.

2.4.1 Overview of the Operational Requirements Simulation Methodology

There are several statistical methodologies that have been used in renewable integration studies to determine hourly and sub-hourly operational requirements and, by inference, integration costs.[40] This study uses a stochastic process developed by the ISO and Pacific Northwest National Laboratory (PNNL)[41] that employs Monte Carlo simulation, which uses random sampling over multiple trials or iterations to estimate the statistical characteristics of a mathematical system. The simulation is designed to model aspects of the daily sequence of ISO operations and markets in detail, from hour-ahead to real-time dispatch. The objective is to measure changes in operations at the aggregate power system level, rather than at any particular location in the system. The model provides realistic representations of the interaction of load, wind and solar forecast errors and variability in those time frames and evaluates their possible impact on operational requirements through a very large number of iterations. The model also incorporates some representation of system ramps between hours to improve accuracy.

A detailed description of the statistical analysis methodology is found in the technical appendix issued separately from this document. The basic method is as follows. First, the load and renewable production data is aggregated from the 1-minute data set to create averaged hour-ahead and 5-minute dispatch schedules for each hour of the year.

Second, the probability distributions of forecast errors, and other statistical properties, such as autocorrelation, for load, and wind and solar production in the hour-ahead and 5-minute-ahead timeframes are constructed. These distributions were developed from various sources, including the ISO and AWS Truepower data on wind forecast errors by location in California, and available data and additional modeling of solar forecast errors. Solar forecast error data is not yet widely available, so a detailed model to estimate those errors was developed that took into consideration the annual and daily patterns of solar irradiance, an hour-to-hour clearness index,[42] dynamic patterns of the cloud systems, types of solar generators, geographical location and spatial distribution of solar power plants, and other factors. Both wind and solar forecast errors are used in the hour-ahead random draws. However, in the 5-minute time frame, the ISO uses a wind persistence

[40] Earlier studies of California operational requirements using alternative statistical methods include the California Energy Commission, "Intermittency Analysis Project" (2007), CEC-500-2007-081 at http://www.energy.ca.gov/2007publications/CEC-500-2007-081/CEC-500-2007-081.PDF (hereafter "CEC IAP Study"). The ISO's 2007 Report adopted a different statistical method, which is developed further in the present study.

[41] See Makarov, et al., "Operational Impacts of Wind Generation on California Power Systems," *IEEE Transactions on Power Systems*, Vol. 24, No. 2, (May 2009) at 1039.

[42] The clearness index is a measure of the actual solar irradiance divided by the maximum solar irradiance; see the technical appendix.

forecast, which is the basis for the simulation. Hence, in the 5-minute sampling, the wind variability is preserved but the forecast error is static for the period of the persistence model. For the solar resources, the 5-minute persistence forecast is based on the clearness index, but the morning and evening ramp periods for solar are also modeled explicitly, during which persistence would not be an appropriate assumption.

Third, the Monte Carlo sampling then conducts random draws from the load, wind and solar forecast errors, with consideration of autocorrelations between the errors, to vary the initial hour-ahead and 5-minute schedules. The Monte Carlo sampling is done on each hour in the sequence individually.[43]

To facilitate analysis, the values generated from the sequence of hours being modeled are evaluated on a seasonal basis and the results for each hour are presented at that level of granularity (i.e., by season, by hour of day). These hourly results by season are shown in Section 4 and Appendix A. The seasonal time frame for presenting results was considered to provide sufficient information on changes in operational requirements over the season, and to capture sufficient variation among the seasons.

Each simulation of a seasonal case includes 100 iterations over all hours in the season to capture a large number of randomly generated values. Of these simulated values, five percent are eliminated as extreme points, using a methodology that considers all dimensions being measured in the analysis (capacity, ramp and ramp duration).[44] In the discussion that follows in Section 4, the ninety-fifth (95^{th}) percentile value is called the "maximum".

Fourth, the remaining values from each full set of iterations are then evaluated using different measures. For example, the 2007 Report showed the maximum value for each operating day hour (i.e., Hour 1 through Hour 24) across the season, to highlight the maximum operational stress likely to be experienced. This study also shows the distribution (maximum, minimum, and average ± one standard deviation) of the maximum values for all hours in the seasonal simulation, to provide more information on the frequency of particular values across the season.[45] However, the basic methodology is the same in both studies.

The specific application of this methodology to evaluate load-following and regulation requirements is discussed in the next sections.

[43] However, the twenty (20) minute ramps that characterize the boundary between actual hourly schedules are represented in the model to ensure that in those periods, deviations between the underlying schedules and the random draws do not exaggerate the result.

[44] See discussion in the 2007 Report and the technical appendix to this report.

[45] That is, assuming a 90 day season, each of the 100 iterations runs through all hours of the season – day 1, hour 1, hour 2, …, day 2, hour 1, hour 2, …, day 90, hour 1, hour 2. This results in 100 values for each hour in the season. Of these 100 values, the maximum value is selected. Then all the hour 1s are grouped, as are all the hour 2s, hour 3s and so on. That results in 24 sets of 90 values, since there are 90 hour 1s, 90 hour 2s, and so on.

2.4.2 Determination of simulated load-following requirements

The statistical methodology described above can be used to evaluate operational requirements that correspond to the time-steps in which the data is sampled. The furthest forward in time that this study evaluates is the transition from hour-ahead schedules to intra-hour schedules and dispatch, which is called load-following. In the context of this analysis and the ISO market, load-following is defined as the intra-hour energy deviations from the hourly schedule, whether in the upward or downward direction. Such deviations can be measured in different ways and on different time-scales within the hour (e.g., 5 minute, 10 minute); generally, in this report, it refers to deviations in the ISO's 5-minute economic dispatch intervals.

Table 2.5 shows four different ways in which this study has measured and evaluated load-following requirements and capabilities, both through simulation and empirical analysis. The methods described in this section are listed as the first two in the table.

As noted above, the underlying data for the Monte Carlo simulation is based on 1-minute data that is then averaged to establish hourly schedules and 5-minute dispatch schedules for each hour. The objective of this approach to the simulation was to model data on time frames that correspond to the ISO's hour-ahead scheduling process and real-time unit commitment process, although the simulation itself does not "connect" each interval that it models through an optimization, as do the actual market processes. The hour-ahead scheduling process runs 75 minutes prior to each operating hour using the wind schedules and load forecasts available at that time. The hour-ahead wind schedule for about half of the wind resources currently on the system is constructed through a centralized forecast and made available to the ISO through the arrangements in the Participating Intermittent Resource Program (described in Section 2). The real-time unit commitment runs on a much shorter time horizon, and creates a schedule for economic dispatch of generators on a 5-minute basis. To restate the methodology in ISO scheduling and market terms, the operational requirements simulation defines load-following as the amount of incremental and decremental energy required to serve the MW difference between the hour-ahead scheduling process schedule and the real-time unit commitment and dispatch schedules for each 5-minute interval in the hour, as discussed next.

As noted above, the random draws of forecast errors then generate one value for each hour of the season and twelve values corresponding to each 5-minute interval within each hour, for each of 100 iterations. The method then calculates two quantities that are relevant to load-following. The first is called "load-following capacity" (MW); the second is called "load-following ramp rate" (MW/5 minutes). Load-following capacity is defined as the maximum difference between the hourly "schedule" MW calculated by the simulation and any 5-minute interval MW within that hour. That is, the largest *potential* movement upward and downward over the hour from the hourly schedule. The load-following ramp rate is defined as the difference between the MW in any two contiguous 1-minute intervals within the dispatch intervals in the hour. The maximum load-following ramp rate is thus the largest of these, and the duration of the ramp rate is also measured ex post. These results are presented in Section 4 to show the distribution statistics or simply the maximum value for each hour of the day by season.

Figure 2-5 shows the analytical flow of the load-following calculation. The full mathematical model is presented in the technical appendix.

Table 2.5: Comparison of definitions of "load-following" in study analysis

Analysis	Term	Description/Definition
Operational requirements simulation (Section 3)	Load-following capacity requirement	The maximum difference between the simulated hourly block schedule and any positive deviation from that schedule in the simulated 5 minute schedules (load-following up) or negative deviation (load-following down)
Operational requirements simulation (Section 3)	Load-following ramp rate	The maximum change between the MW level in any two consecutive simulated 1 minute intervals within an hour; can also be calculated for other intervals within the hour or over multiple hours
Operational capability based on actual market analysis (Section 4)	Actual 5-minute load-following capability	The estimated upward and downward capability of the generation committed and dispatched in actual five minute intervals, based on ramp rates and maximum and minimum operating limits
Operation capability based on production simulation (Section 5)	5-minute Load-following capacity	The cumulative capability of the units dispatched in the simulation to move in 5-minutes, subject to their ramp rates

2.4.3 Determination of simulated regulation requirements

The calculation of the regulation requirements proceeds similarly to the load-following analysis, but measuring deviations between the 5-minute dispatch intervals and the 1-minute data that underlies the analysis. In this case, the method measures the largest 1-minute deviation within the 5-minute period to give the regulation result. The "regulation capacity" requirement is defined as the largest such deviation within an hour. The "regulation ramp rate" is defined as the largest sampled change from minute-to-minute within the 5-minute interval.

Figure 2-6 shows the analytical flow of the regulation calculation, with additional detail available in the separate technical appendix.

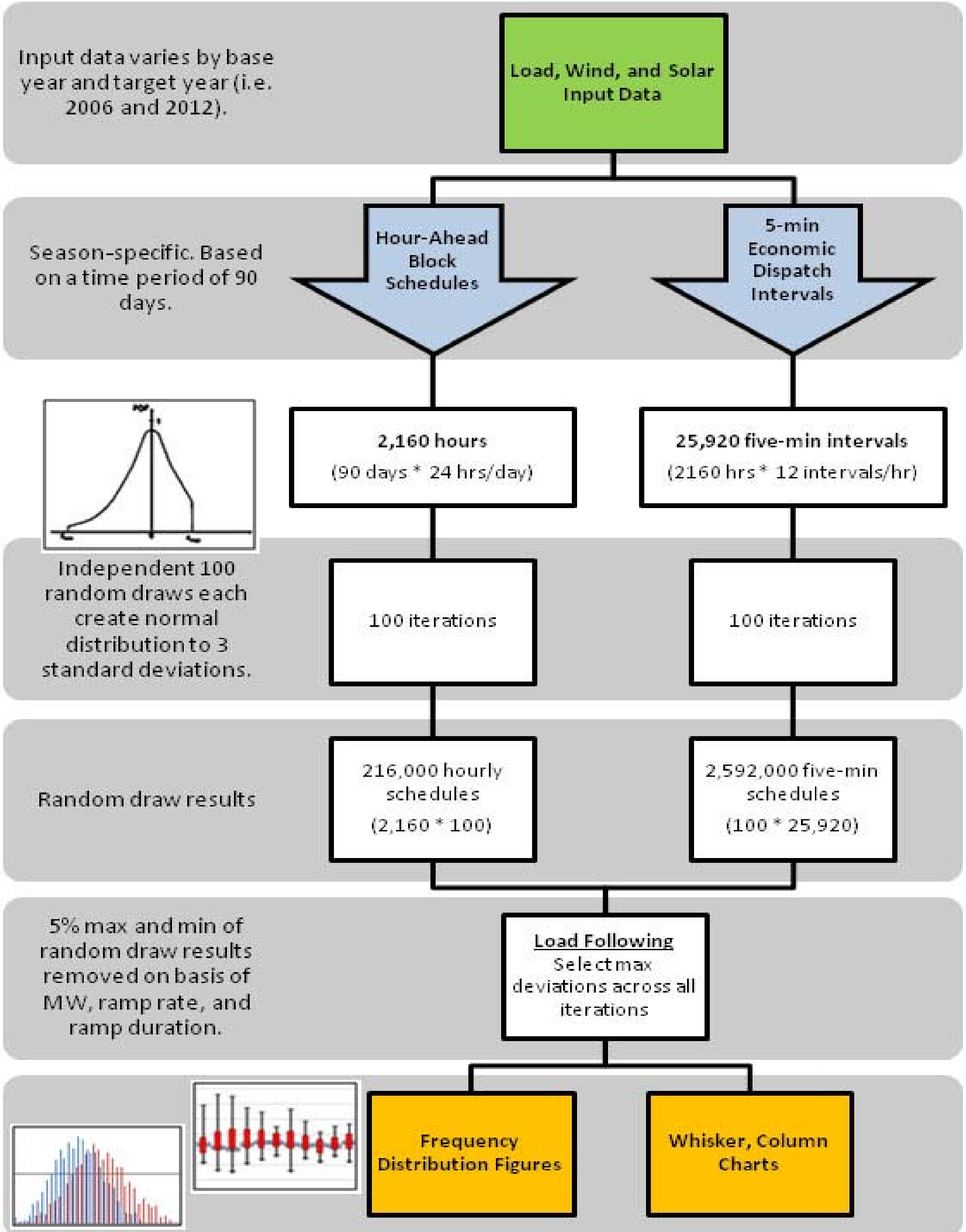

Figure 2-5: Analytical Flow Chart for Calculating Load-following Capacity Requirements

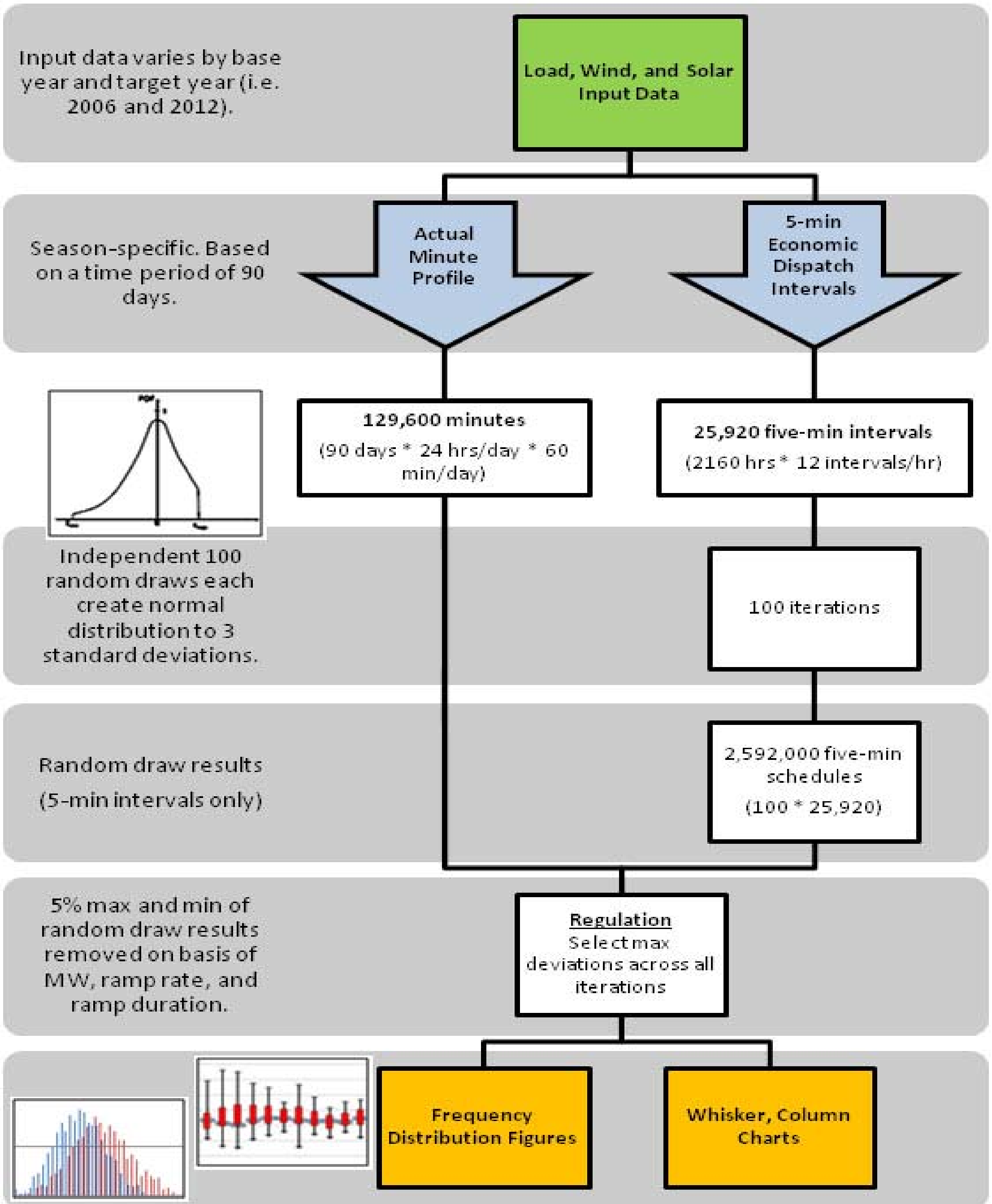

Figure 2-6: Analytical Flow Chart for Calculating Regulation Capacity Requirements

2.5 Production Simulation Methodology for Evaluation of Fleet Capability

One limitation of the operational requirements methodology is that it does not represent the supply side of the power system explicitly. That is, while estimating operational requirements, the statistical analysis does not address the capability of the ISO generation fleet to meet those requirements during market and system operations.

The analysis of generation fleet characteristics, historical bids and the historical dispatch described in Section 4 evaluates whether sufficient regulation and load-following capability exists to meet the integration requirements, based on historical operations. By juxtaposing the historical capability with the future operational requirements, it is possible to arrive at some conclusions regarding the capability of ISO generation fleet to meet the integration requirements with 20 percent renewable generation.

However, to analyze in detail the capability of the fleet to meet the integration requirements, it is necessary to conduct simulations of both hourly and minute-by-minute operations under future load and generation scenarios. The production simulation models developed for this study sought to replicate with a reasonable degree of accuracy the operational and market processes used in the commitment and dispatch of generation. It incorporated all the physical characteristics of the generators, such as ramp rate, start-up costs and time, minimum up-time, minimum down-time, etc. However, it did not include certain generator operating constraints, such as forbidden regions.

Production simulation (or production cost modeling) refers to the use of large-scale computer-based models that incorporate a detailed representation of generation, demand and transmission over a wide region to simulate least cost commitment and dispatch of generators subject to operational constraints and determine marginal prices at different locations in the system. Due to their scale, these types of models are typically used for planning purposes and not for market or operational evaluation. However, over recent years, many models have incorporated sufficient detail on generation and transmission network parameters, as well as updated their optimization algorithms for efficient unit commitment solutions, such that they are now also used to evaluate shorter-term market and operational conditions. Typically conducted on an hourly time-step, current state-of-the-art production simulation models can represent both unit commitment – the decision whether to start (commit) or stop (decommit) a particular resource in a particular period – and dispatch – the actual output from a particular resource in a particular period. They also explicitly represent key generation operating characteristics, such as start-up times, ramp rates and minimum up and down times.

Most of the large-scale regional wind integration studies to date have employed production simulation models to evaluate the capability of generation and non-generation resources to meet energy and ancillary services requirements under different future conditions.[46] These production simulations have used an hourly time interval for

[46] For a recent survey, see M. Milligan, et al., Large-Scale Wind Integration Studies in the United States: Preliminary Results, Conference Paper, NREL/CP-550-46527, September 2009; See also California Energy Commission, "Intermittency Analysis Project" (2007), CEC-500-2007-081 at http://www.energy.ca.gov/2007publications/CEC-500-2007-081/CEC-500-2007-081.PDF; See also several

dynamic optimization, with the capability of the system to meet the sub-hourly requirements such as load-following evaluated heuristically based on the results of the hourly simulation and not explicitly determined via sub-hourly optimization. Also, most of the prior studies have employed deterministic production simulation, which does not adequately model the impact of uncertainties in load and variable generation. The stochastic, sequential simulation methodology employed in this study was designed to overcome the above-mentioned problems. This methodology is described below in Section 2.5.2 in detail. The data and assumptions used in the production simulation model are described next.

2.5.1 Data and Assumptions

The major objective of production simulation is to model the least cost operation of a power system while ensuring that the system's security constraints are not violated. Security constraints include the operating limits and capabilities of generation sources, constraints and contingencies imposed by the transmission system and the operational limits such as minimum operating reserve levels. The primary inputs are hourly loads, generator capacity and characteristics, fuel prices and transmission constraints that need to be monitored. This section provides the data and assumptions for the production simulation model used in this study.

2.5.1.1 General data and categorizations

The source for the identity and operating characteristics of the conventional resources incorporated into the production simulation model was the full network model used for allocation of ISO congestion revenue rights, and the ISO Master File, respectively. The ISO's Master File data includes all key generator confidential operating characteristics such as Pmin, Pmax, minimum up and down times, ramp rates, start times, heat rates, and ancillary service certified ranges. Table 2.6 describes how classes of resources are modeled in the production simulations. In this analysis, the generation from certain resources such as biomass, geothermal, and Qualifying Facilities (QFs) are assumed to be fixed based on historical operations. Hydro generation, although dispatchable, is assumed to be fixed based on either 2006 or 2007 hydro data, in order to study two different extremes in hydro generation. Similarly, a portion of imports is assumed to be fixed to reflect historical operations. Only gas-fired units are dispatchable in this analysis. These assumptions are further explained in the sections below.

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studies conducted by GE Consulting, including New York State Energy Research and Development Authority's "The Effects of Integrating Wind Power on Transmission System Planning, Reliability, and Operations, " available at http://www.nyserda.org/publications/wind_integration_report.pdf ; Ontario Power Authority, Independent Electricity System Operator, Canadian Wind Energy Association, "Ontario Wind Integration Study," available at http://www.powerauthority.on.ca/Storage/28/2321_OPA_Report_final.pdf ; Electrical Reliability Council of Texas, "Analysis of Wind Generation Impact on ERCOT Ancillary Services Requirements," available at http://www.ercot.com/news/presentations/2008/Wind_Generation_Impact_on_Ancillary_Services_-_GE_Study.zip.

Table 2.6: Modeling assumptions about production profiles and flexibility by generation resource type and imports

Generation Type	Production Simulation -- Assumptions about Commitment and Dispatch
Solar	Simulated production profiles based on solar irradiance data; variable over the day (on both an hourly and intra-hourly basis); not dispatchable
Wind	Simulated production profiles from historic production data; variable over the day (on both an hourly and intra-hourly basis); not dispatchable
Biomass	Scaled historic production profile; constant over the day; not dispatchable
Geothermal	Fixed production profile; constant over the day; not dispatchable
Thermal	Dispatchable in each time-period within generation operating parameters
Hydro	Historical production and ancillary service profile (2006 and 2007); typically constant over the day; not dispatchable
Nuclear	Fixed production profile; constant over the day; not dispatchable
QF	Historic production profile; constant over the day; not dispatchable
Imports	Historic injection for 2006 and 2007; varies by hour; not dispatchable (but varied in sensitivity analysis)

2.5.1.2 Existing Conventional Gas Resources

Thermal resources in the study provide about 32,308 MW of the capacity within the ISO BAA, which would account for approximately 54 percent of the ISO's total resource mix in 2012. Gas plants are particularly important because they currently provide most of the ramping and ancillary service capability for the ISO. In this study, the gas-fired generation is assumed to be dispatchable; i.e., self-schedules of gas-fired generation are not modeled.

Tables 2.7 through 2.9 provide summaries of the various technology types and some of their operational characteristics.

Table 2.7: Ramp rates of ISO generation fleet

Generation Type		Ramp Rate (MW/min) by Category						
		RR < 0.5	0.5 ≤ RR < 1	1 ≤ RR < 5	5 ≤ RR < 10	10 ≤ RR < 20	20 ≤ RR	Total MW
Non-OTC Units	Combined Cycle			4,885	4,630	3,617		13,132
	Dynamic Schedule				552	1,746	2,379	4,676
	Gas Turbine	32	68	1,040	4,635	1,601	553	7,929
	Hydro	99	157	427	1,135	1,927	3,671	7,416
	Other	5	4	14	1,633		4	1,660
	Pump/Storage				440		1,792	2,232
	Recovery	61	17	115	13			206
	Steam	357	355	1,328	747	59		2,847
	Not specified	5	6	42	1,568	20	525	2,165
Non-OTC Unit Total		559	607	7,851	15,353	8,970	8,924	42,263
OTC units	Combined Cycle			600				600
	Gas Turbine			15				15
	Steam		354	8,542	5,650	1,516	1,510	17,573
OTC Unit total		0	354	9,158	5,650	1,516	1,510	18,188
All Units Total		559	961	17,008	21,003	10,486	10,434	60,451

Table 2.8: Definitions and characteristics of units based on start-times

Attribute	Fast-Start	Short-Start	Medium-Start	Long-Start	Extremely Long-Start
Start-up Time	Less than or equal to 10 minutes	Less than 2 hours	Between 2 & 5 hours	Between 5 & 18 hours	Greater than 18 hours
Cycle time		Less than 5 hours	Less than 5 hours		

Table 2.9: Start up times of ISO generation fleet

Generation Type		Start-up Times (minutes) by Category					
		ST < 10	10 ≤ ST < 120	120 ≤ RR < 300	300 ≤ RR < 10,800	unknown	Total MW
Non-OTC Units	Combined Cycle		174	1,241	11,717		13,132
	Dynamic Schedule				3,650	1,026	4,676
	Gas Turbine	1,261	2,161	191		4,317	7,929
	Hydro	4,908	1,382	486		640	7,416
	Other	352	294	377		636	1,660
	Pump/Storage	2,232					2,232
	Recovery	19	35	114		37	206
	Steam	267	169	221	1,760	430	2,847
	Not specified	360	114	19		1,672	2,165
Non-OTC Unit Total		9,400	4,329	2,649	17,127	8,759	42,263
OTC units	Combined Cycle			109	491		600
	Gas Turbine					15	15
	Steam				15,127	2,446	17,573
OTC Unit total				109	15,618	2,461	18,188
All Units Total		9,400	4,329	2,758	32,745	11,220	60,451

2.5.1.3 Expected Additional Conventional Gas Resources by 2012

Table 2.10 shows the new and planned thermal resources that were included in the analysis. These resources were included as they are currently under construction and have little or no risk of not being available in the 2012 timeframe. No resource retirements were modeled, nor were sensitivities conducted for the status of once-through cooling (OTC) plants. OTC plants are slated to be retrofitted or shut down after 2013 and are not expected to affect the 20 percent RPS integration. However, they could affect renewable integration after 2013, and hence are being examined in the ISO's 33 percent RPS operational study.

Table 2.10: New Resource Additions by 2012

	New Resources	Max. Cap. (MW)	Location	Commission Date
1	EIF_Panoche_2_PL1X2	400	Fresno, NP15	August 2009
2	GateWay_2_PL1X4	530	Contra Costa, NP15	May 2009
3	Humboldt_1_PL1X2	163	Humboldt, NP15	April 2010
4	Inland_Emp_2_PL1X4	800	Riverside, SP15	Unit 1: Nov. 2008 Unit 2: July 2009
5	Otay_Mesa_2_PL1X2	590	San Diego, SP15	October, 2009
6	Starwood_1_PL1X2	120	Fresno, NP15	May 2009
7	Colusa Generating Station	660	Colusa, NP15	October, 2010
Total		3,263		

2.5.1.4 Imports of Energy and Ancillary Services

To simplify the analysis, and to keep it focused on the operational capabilities of the generation fleet under ISO dispatch control, the production simulation used fixed imports of energy based on historical import data. The ISO is a net importer of energy and this is not likely to decrease in the near future. The 2012 import levels used in this study were based on the actual import profiles for 2006 and 2007. As discussed further in the next section, during high hydro years within the ISO's footprint, imports are significantly lower than they are during low hydro years. Thus, the combination of the hydro patterns and imports for 2006 and 2007 are a useful starting point for examining the sensitivity of renewable integration to alternative system conditions.

During the off-peak hours in 2006, the average imports exceeded 5,100 MW in the spring and 5,500 MW in the summer months. During the off-peak hours in 2007, the average imports were 7,000 MW in the spring and 6,900 MW in the summer. Some of the reasons for high import levels during the off-peak hours are jointly owned units that are dynamically scheduled into the ISO, load-serving entity contracts to purchase base-loaded energy from out-of-state coal plants, and external resources that are needed to serve the ISO's peak demand but cannot be shut down by the host balancing authorities due to their long start up times and shut down times between starts. In cases where the ISO needs the peak energy from an external resource it may have to also take the minimum generation from that resource during the off-peak hours because the host balancing authority may not need the off-peak generation.

In the model, ancillary services imports over the interties were assumed to be zero, in part due to the limitations of the model to represent dispatch of external resources and also because the analysis was focused on the renewable integration capability of the existing in-state generation fleet.

It is expected that the energy import levels modeled here will be available in 2012; the study did not scale up the imports (i.e., assume that there will be additional surplus generation outside the ISO) on the assumption that in other regions, generation additions will at least keep up with expected load growth.

To examine the sensitivity of the results to import assumptions, the production simulation analysis included several alternative cases that varied the level of imports considered fixed and the level considered dispatchable. Subsequent studies, notably the forthcoming 33 percent RPS operational study, will use a WECC-wide model that can examine regional energy trade balances and ancillary service provision.

2.5.1.5 Hydro Resources

The off-peak hydro production levels could average 3,822 MW (49 percent) of total capacity during the spring, about 2,707 MW (35 percent) in the summer and 2,337 MW (30 percent) during the winter months. Also in the spring, high temperatures can result in early snow melt and high hydro production levels, which can result in overgeneration conditions because the off-peak loads in the spring is typically about 2,000 MW lower than the off-peak loads in the summer. Since the hydro capacity is expected to remain about the same in the 2012 timeframe, the realized hydro production levels can greatly influence the amount of wind generation that can be accommodated into the resource mix.

The study used two sensitivities for hydro production: a high hydro case based on actual production in 2006; and a low hydro case based on actual production in 2007. The ancillary services (spinning reserve, non spinning reserve and regulation) awarded to hydro resources were assumed to be the same as 2006 and 2007.

Table 2.11: Comparison of Hydro and Imports in 2006 and 2007 (GWh/yr)

	2006	2007	percent diff.
CA hydro	48,876	26,958	-45 %
CA net imports:			
From NW	19,808	24,669	25 %
From SW	44,959	67,547	50 %
Total	**64,767**	**92,216**	**42 %**

The hydro profiles used in the simulation were actual production for 2006 and 2007. 2006 was declared a high hydro year due to the higher than normal rainfall, snowpack and reservoir storage levels. By comparison, 2007 was declared a normal hydro year.

Overall, hydro production was 48,876 GWh in 2006 and 26,958 GWh in 2007, a reduction of 45 percent. The ancillary services modeled in the production simulation studies were assumed to be the same as was provided by the hydro resources in 2006 and 2007.[47] Typically, during high hydro years in California, the ISO imports are significantly lower than during dry hydro years. As shown in Table 2.11, a high hydro year has a significant impact on imports.

[47] Availability of hydroelectric production is a major influence on the availability of regulation. Hydroelectric resources typically provide a large fraction of the regulation utilized by the ISO, and are among the most flexible resources available, so anything that impacts their ability to provide the service has a noticeable impact on the market. Water conditions can directly affect the capability of hydro resources to provide regulation. In 2006, hydro generation was at high capacity, such that hydro generators were forced to either generate at maximum capacity or allow water to go over spillways. Under these circumstances, hydro units had no spare capacity to provide for regulation and other resource types were used to make up for reduced hydro availability. In the spring of 2006, there was insufficient upward regulation capacity in the market a total of 104 hours, distributed fairly evenly across all hours of the day. Upward regulation from hydro resources hovered in the 150 MW range in 2006, but was in the 200 MW range in the comparatively lean water year of 2007. In the spring of 2007, hydro units were not producing energy at their maximum capacity, and were therefore able to offer regulation capacity to the market. By comparison, insufficiency occurred in only 5 hours during January through May 2007 period, when water levels were much lower.

2.5.1.6 Modeling of Other Generation Resources

In 2006, of the four nuclear units within the ISO area, two units were off-line for some time in the spring and one unit was off-line for a period of time during the fall and winter months. In subsequent years, it is highly likely that all four units would be on-line and generating at their maximum capacity during off-peak hours. Therefore, all four nuclear units were modeled at a combined full output of 4,550 MW.

Qualifying Facilities (QFs) were modeled at their historic production profiles in 2006 and 2007; actual QF production does not vary much from one hour to the next and is not modeled as dispatchable (typically, QFs are only given dispatch instructions when the ISO declares an emergency). Although geothermal and biomass resources are classified as QFs, for accounting purposes, their actual production was not included in the QF total but instead counted as renewable energy to meet the RPS.

2.5.1.7 Renewable Resource Operational Characteristics

All RPS-eligible renewable resources, including variable generation renewables, were modeled as fixed output (or “must-take”) generation. Wind and solar production profiles were discussed above in Section 2.2. Geothermal, biomass and small hydro facilities were modeled based on their historic production profiles realized in 2006 and 2007 and incremented to 2012 production levels as appropriate.

2.5.1.8 Load Forecasts and Assumptions

Load forecast assumptions were discussed in Section 2.1. The minute-by-minute load data for 2012 was averaged to obtain the 5-minute and hourly load for the production simulations. The methodology used for simulating day-ahead and hour-ahead loads using forecast error is described in the technical appendix.

2.5.1.9 Network Representation

The ISO service territory was modeled as three transmission regions—PG&E, SCE and SDG&E—but transmission limits were only enforced on Path 26. As noted above, hourly net interchange for NP26 and SP26 were fixed based on 2006 or 2007 actual data. A full network representation was not employed since it would have greatly increased the solution times of the stochastic simulations.

2.5.1.10 Ancillary Service Requirements

The production simulation model co-optimizes energy and ancillary services, such as regulation, spinning and non-spinning reserves. The ancillary service requirements used in the simulations are listed in Table 2.12. As noted above, they include the seasonal maximum regulation requirements by operating hour calculated in the operational requirements simulations. Those actual requirements are shown in Section 3 and Appendix A-1. However, the model did not represent ancillary service procurement requirements on a regional and sub-regional basis.

Table 2.12: Ancillary Service Requirements

Ancillary Service	2007 Report Requirements for Incremental Wind Case	Requirements for Incremental Wind plus Solar Case
Regulation-Down	350-750 *	350-775 *
Regulation-Up	350-530 *	350-525 *
Spinning	0.5 × (3 percent × Load + 3 percent × Generation)	0.5 × (3 percent × Load + 3 percent × Generation)
Non-Spinning	0.5 × (3 percent × Load + 3 percent × Generation)	0.5 × (3 percent × Load + 3 percent × Generation)

* Regulation requirements vary by time of day and season.

2.5.2 Stochastic Sequential Production Simulation Methodology

For this study, the ISO developed a more detailed modeling approach to production simulation than most prior renewable integration studies. A stochastic, sequential production simulation with the capability to simulate both hourly commitment and dispatch and 5-minute real-time dispatch was developed for this study. The methodology considered the impact of day-ahead and hour-ahead wind and load forecast errors on unit commitment and dispatch, thereby replicating to some degree the actual sequence of those forward markets and procedures. As discussed below, the hour-ahead commitment is then frozen and the units dispatched to serve net load across 5-minute "real-time" intervals. This process is repeated for 100 iterations to test the impact of multiple possible forecast errors that need to be resolved in the actual dispatch. The technical appendix provides the mathematical details on the methodology.

2.5.2.1 Generation of stochastic load and wind generation forecasts

The further forward in time, the greater the uncertainty about actual (real-time) wind and load due to forecast error. A stochastic process using Brownian motion with mean reversion was developed to generate a random sequence of day-ahead and hour-ahead load and wind forecasts errors for each hourly interval in 2012. The stochastic process was specified using the statistical properties—mean, standard deviation, autocorrelation, and cross-correlation—of the actual day-ahead and hour-ahead load and wind forecast errors. The cross-correlations are composed of the inter-regional correlation of load forecast errors, wind inter-zonal correlations, load-wind correlations and day-ahead and hour-ahead correlations. The statistical properties are derived for four seasons: spring, summer, fall and winter. However, the random process did not include solar forecast errors, although the solar profiles with their actual variability were used to establish the hourly and 5-minute net loads.

The stochastic process was used to generate 100 different day-ahead and hour-ahead load and wind generation forecasts for evaluation of alternative unit commitment and dispatch realizations. These were then used in the process described next.

2.5.2.2 Sequential day-ahead to real-time simulations

The analytical flow of the stochastic, sequential production simulation methodology is depicted in Figure 2-7. The first step in this methodology is the simulation of the day-ahead market with a day-ahead load and wind forecast. The model did not include a day-ahead solar forecast, but rather modeled solar production as a fixed hourly profile. The day-ahead market simulation is an hourly simulation for the entire study year (8760) hours. This simulation is performed 100 times using the day-ahead load and wind generation forecast errors described in the previous section. This simulation uses a 24-hour optimization window, with a 24-hour look-ahead to account for long-start units.

The next step in the sequential simulation is the "hour-ahead" simulation which lines up in time with the ISO's hour-ahead scheduling procedure and with the submission of wind schedules in the Participating Intermittent Resource Program. The commitment status for the extremely long- and long-start generators are passed from the day-ahead simulation and frozen in the hour-ahead simulation. As in the case of the day-ahead simulation, the hour-ahead simulation is an hourly simulation for the entire study year (8760) hours. This simulation is performed 100 times using the hour-ahead load and wind generation forecast errors. The day-ahead and hour-ahead load and wind generation forecast errors are correlated. This simulation uses a 6-hour optimization window. The hourly unit commitment status for the extremely long-, long-, medium-, and quick-start generators are queried by iteration from the solution and passed to the "real-time" 5-minute simulations, which are described next.

In the real-time simulation unit commitment and dispatch, the resource and network data are the same as that in the day-ahead and hour-ahead simulations. The loads and variable energy resource generation are the "actual" data prior to the introduction of forecast errors, and averaged from the underlying 1-minute data to the 5-minute intervals. The solution is the co-optimization of energy and ancillary services with generation unit commitment and dispatch.

To reduce the computational burden, a selected number of days that exhibited interesting operational challenges were selected for this detailed simulation process to examine the impact on load-following and overgeneration. To identify these days or hours, the ISO undertook a variant on what is called "importance sampling."[48] This is a method for choosing most likely scenarios, or in this case, most likely periods for ramp violations, ancillary service shortfalls, or overgeneration events. The procedure used to identify interesting days for real-time simulations is described in Appendix C-1.

[48] See, e.g., description as applied to the ISO's Transmission Economic Assessment Methodology (TEAM), (2004), pg. 5-8.

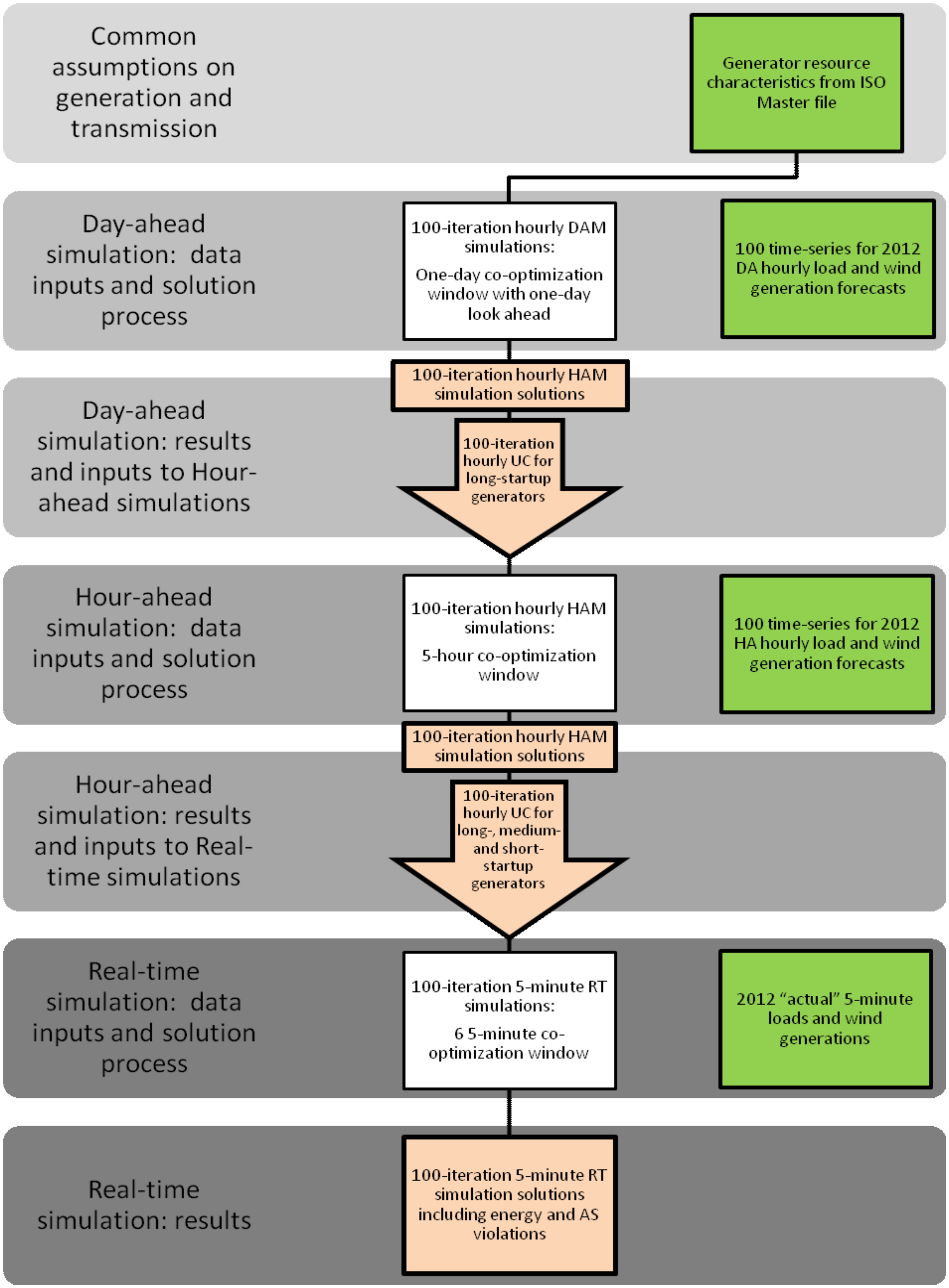

Figure 2-7: Flowchart of the Stochastic, Sequential Production Simulation Methodology

3 Analysis of Operational Requirements

This section and appendices A-1 and A-2 present the updated estimates of operational requirements under a 20 percent RPS, along with a comparison to analogous results from the ISO's 2007 Report and other relevant studies. This section focuses on results from the Summer 2012 simulation; results for other seasons are in Appendix A-1. In addition, Appendix A-2 shows additional sensitivity results for Summer 2012.

The simulation results provide information on a number of operational and market relevant questions, including the simulated seasonal maximum requirements by hour of day[49] and other distribution statistics – average, range (maximum, minimum), frequency of the requirement – over each hour of the season based on different subsets of the simulation results.[50] The seasonal maximum hourly requirement is important information for operational reasons, to provide the ISO with the largest magnitudes of potential requirements. The other statistics are to provide both the ISO and market participants with information about the expected frequency and magnitudes of the operational requirements over the course of each season. This is particularly true for wind production as the input data set to the simulations captures variations in wind production over the entire target year (2012) based on historical production data.

In the 2007 Report, only the seasonal maximum hourly operational requirements by hour of day were reported.[51] At the time, the objective of the analysis was solely to provide results for system operational preparations. In addition, the study used only one wind production profile for the year (based on average capacity factors from historical data), and thus there was concern that additional statistics on the results could be misleading, given that other annual wind profiles could have generated different results, although the maximum requirement results would probably not change substantially.

Moreover, as noted in Section 2.2, the statistical simulations of regulation requirements do not consider the effect of other real-time considerations, such as generator uninstructed deviations in real-time dispatch, as well as day-ahead forecast errors of wind and solar production that could affect day-ahead procurement of regulation and possibly other ancillary services at higher levels of variable energy production. Currently the ISO procures a minimum of 300 MW of Regulation Up and Regulation Down in the day-ahead market to cover peak hour load requirements and those other considerations. The ISO expects that this will remain a minimum requirement, even for hours in which the simulation results shown here suggest a possible "real-time" requirement of less than 300 MW. The ISO believes that the simulation results are a better indicator of the potential need for procurement of above 300 MW of Regulation in certain hours due to forecast

[49] i.e., the maximum seasonal requirement for each hour of the day from the 100 iterations of the simulation of the 90 days of the season

[50] Section 3 describes the results yielded from the 100 iterations of each season. The other statistics are generated from this underlying data set.

[51] See 2007 Report, sections 5.8.3 and 5.10.1 as well as Appendix A; available at http://www.caiso.com/1ca5/1ca5a7a026270.pdf.

variable energy resource production. Further simulations of different wind production profiles and consideration of other factors, such as day-ahead (rather than hour-ahead) forecast errors, could thus improve understanding of the relationship between operational requirements in real-time and market procurement forecasts day-ahead.

However, the ISO believes that there is market value to providing some of the other statistics on the simulation results. In particular, these additional statistics clarify that the average ± one standard deviation of the simulated values for operational requirements for particular hours of the day over the season can be substantially less than the maximum seasonal requirements for those hours, particularly for the daily peak hours when wind production is typically at a low capacity factor. Moreover, in actual operations, the ISO uses daily and hourly forecasts of load and renewable energy production, and has continuously improved its wind and ramp forecasting capabilities. Hence the ISO will not, in practice, commit resources day-ahead to meet a simulated seasonal maximum operating requirement for a particular hour in which that maximum requirement is not forecast.

As noted in Section 3, the statistical method for calculating these requirements does not evaluate whether the existing generation fleet can meet them. To provide that evaluation, the regulation requirements presented in this section are then compared in Section 4 with historical ISO procurement of regulation and are also explicitly incorporated into the production simulations to further test the capability of the generation fleet to meet them. The load-following requirements are also compared in Section 4 to ISO historical data, but are not explicitly incorporated into the production simulations, which instead attempt to replicate load-following for selected days by conducting sequential day-ahead to real-time unit commitment and dispatch simulations.

Organization of results

The discussion of the simulated load-following and regulation requirements is organized into three categories of results that are found in this section and appendices A-1 and A-2:

1. Portfolio results with all forecast errors, in which the analysis is of the combined wind and solar portfolio and there is no evaluation of changes in forecast error [Section 4 and Appendix A-1];

2. Requirements by renewable technology, in which the simulations are re-run with and without particular technologies to distinguish the impact of incremental solar resources only, incremental wind resources only, and the full renewable portfolio [Appendix A-2]; and the

3. Impact of forecast error and variability, in which the simulations are re-run to distinguish the differential effect of these factors [Appendix A-2].

In all instances, references to the operational requirements in 2006 refer to the *simulated* operational requirements for the reference year. Like the 2007 Report, the results reported in the following tables and figures as maximums are the 95th percentile occurrence for a particular hour.[52]

3.1 Summary of Findings

The simulation results are summarized as follows.

Load-following

- The maximum hourly simulated load-following up and load-following down capacity requirements in 2012 are 3737 MW and -3962 MW, respectively, compared to 3140 MW and -3365 MW for simulated 2006 levels.

- The maximum hourly simulated load-following up and load-following down ramp rates in 2012 are forecast as 194 MW/min and -198 MW/min, respectively, compared to 166 MW/min and -158 MW/min, respectively, for simulated 2006 levels.

- Because most of the renewable production being modeled in 2012 is from wind resources, they are the primary cause of the increased load-following requirements; at the levels modeled, solar resources only slightly alter the load-following requirements in the morning ramp up hours and evening ramp down hours. Obviously, wind is the sole contributor to the incremental load-following requirements in the night-time hours.

- The largest changes in load-following up capacity are in hours 8-9, corresponding to the morning wind ramp down. The changes in load-following down capacity are less concentrated in particular hours, but the average requirements increase in the hours 6-8 corresponding to the morning solar ramp up and the late afternoon or early evening hours, corresponding in part to the wind ramp up. Seasonal results differ, as shown in Appendix A-1.

- The maximum requirements will not be needed in all hours; for example, the percentage increase in aggregate load-following capacity requirements in the summer season between the 2012 and 2006 simulations is estimated at 20 percent for load-following up and 23 percent for load-following down.

- Because the wind and solar ramps are typically inversely correlated in the morning and evening hours, in some of those hours the combination of the two resources slightly reduces the load-following requirements compared to wind resources alone (see Appendix A-2).

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[52] That is, excluding the 5 percent highest results from the simulations.

- The effect of forecast error (load, wind and solar) on the load-following requirement is approximately four times the effect of the inherent variability of load, wind and solar (see Appendix A-2).

Regulation

- The maximum hourly simulated Regulation Up and Regulation Down capacity requirements in 2012 are 502 MW and -763 MW, respectively, compared to 278 MW and -440 MW for simulated 2006 levels.

- The maximum hourly simulated Regulation Up and Regulation Down ramp rates in 2012 are 122 MW/min and -97 MW/min, respectively, compared to 75 MW/min and -79 MW/min, respectively, for simulated 2006 levels.

- However, these requirements will not be needed in all hours; for example, the percentage change in aggregate regulation capacity requirements between the 2012 and 2006 simulations of the summer season is estimated at 43 percent for regulation up and 12 percent for regulation down. An important caveat is that there are drivers of regulation procurement not considered in the simulation; however, the changes in the procurement between the two cases are indicative of future increases of procurement.

- The incremental requirements due to solar are greater during the peak hours of the day than those due to wind, due to the greater production of solar energy in those peak hours. Obviously, wind is the sole contributor to the incremental regulation requirements in the off-peak hours.

- Because the wind and solar ramps are typically inversely correlated in the morning and evening hours, the combination of the two resources slightly reduces the regulation requirements compared to wind resources alone.

3.2 Comparison of Seasonal Results

The seasonal maximum results across all hours from the operational requirements simulations for all four seasons are shown in Table 3.1 and Table 3.2, with a comparison of the base-year simulation result (2006), the 20 percent RPS result (2012), and a 33 percent portfolio RPS (2020) result.[53] The remainder of Section 3 focuses on detailed results for one season: summer. The corresponding results for all seasons are found in

[53] The 33 percent RPS result is from one of the renewable portfolios being studied by the ISO and other entities in a subsequent operational study. The particular portfolio is the CPUC's 2009 "Reference Case" portfolio, which includes an additional 9,700 MW of solar resources (PV and solar thermal) and an additional 8,350 MW of wind resources over the base case. Thirty-three (33) percent RPS portfolios with other technology mixes will produce different results. For the source portfolio, see http://www.cpuc.ca.gov/NR/rdonlyres/1865C207-FEB5-43CF-99EB-A212B78467F6/0/33PercentRPSImplementationAnalysisInterimReport.pdf.

Appendix A-1. Before turning to the summer results, a brief discussion is provided here on seasonal differences and their implications for operational requirements.

As shown in Sections 1 and 2, the typical production profiles for variable energy resources, particularly wind, as well as load profiles vary by season, and the simulation results reflect the differences in average seasonal production and actual variability. Appendix A-1 shows the seasonal results side by side. With respect to load-following, the simulations show higher results in the summer than in the lower load seasons. However, this increase is due more to load variability and forecast error than to changes in the variability and forecast errors associated with the renewable resources.

For regulation up, spring has the highest hourly seasonal maximum value in hour 18. The daily maximums for regulation up tend to be at different times in the different seasons, although all seasons have high values in hour 6 and 18, generally corresponding to the morning wind ramp down and the afternoon solar ramp down. For regulation down, the summer season provides the highest seasonal maximum value in hour 18; however, all seasons have spikes in the regulation down requirement in hour 18. These results are due to the higher wind production in the spring months.

Table 3.1: Change in Simulated Maximum Regulation and Load-Following Capacity (MW) Requirements by Season

	Spring			Summer			Fall			Winter		
	2006	2012	2020	2006	2012	2020	2006	2012	2020	2006	2012	2020
Max Regulation Up Requirement (MW)	277	502	1135	278	455	1444	275	428	1308	274	474	1286
Max Regulation Down Requirement (MW)	-382	-569	-1,097	-434	-763	-1,034	-440	-515	-1,264	-353	-442	-1076
Max Load-following Up Requirement (MW)	2,292	3,207	4,423	3,140	3,737	4,841	2,680	3,326	4,565	2,624	3,063	4,880
Max Load-following Down Requirement (MW)	-2,246	-3,275	-5,283	-3,365	-3,962	-5,235	-2,509	-3,247	-5,579	-2,424	-3,094	-5,176

Table 3.2: Change in Simulated Maximum Regulation and Load-Following Ramp Rate (MW/Min) Requirements

	Spring			Summer			Fall			Winter		
	2006	2012	2020	2006	2012	2020	2006	2012	2020	2006	2012	2020
Max Regulation Ramp Up Rate (MW)	67	122	447	75	118	528	70	114	472	73	107	344
Max Regulation Ramp Down Rate (MW)	-66	-90	-310	-76	-97	-300	-72	-90	-301	-79	-90	-303
Max Load-following Ramp Up Rate (MW)	150	168	325	166	194	313	147	181	324	143	165	296
Max Load-following Ramp Down Rate (MW)	-138	-162	-451	-145	-169	-434	-134	-167	-438	-158	-198	-427

Table 3.3 shows the percentage increase between 2012 and 2006 in the total simulated requirements for load-following and regulation capacity requirements.

Table 3.3: 2012 vs. 2006, Percentage Increase in Total Simulated Operational Capacity Requirements

	Spring	Summer	Fall	Winter
Total maximum load-following up	27.0 %	11.9 %	19.2 %	19.7 %
Total maximum load-following down	29.5 %	14.0 %	21.2 %	21.3 %
Total maximum regulation up	35.3 %	37.3 %	29.6 %	27.5 %
Total maximum regulation down	12.9 %	11.0 %	14.2 %	16.2 %

3.3 *Load-following Requirements for Summer 2012*

This section shows the simulation results for the full 20 percent RPS portfolio assuming all forecast errors (for load, wind and solar) remain within historical experience.

As described in Section 2, load-following capacity in the statistical simulation is defined as the largest deviation between the hourly schedule and any 5-minute interval schedule within the hour. Figures Figure 3-1 and Figure 3-2 show distribution statistics for the set of values that include the *maximum* load-following capacity result for each hour in the season drawn from all 100 iterations of the simulation. The hourly bars are a modification of a typical "stock" chart. The colored line represents the range (minimum, maximum) of the results and the bar shows the average ± one standard deviation. Red bars show the results of the 2012 simulation, while blue bars show the 2006 simulation.

The subset of hours shown in the 2012 result is comprised of the 90 maximum values for each of the 24 hours of the days.[54] Hence, while the distribution of results shown here reflects higher forecast errors drawn across the iterations (although it is also affected by the variability reflected in that hour), it also preserves the actual variable energy resource production profiles such that hours with low production are on average shown to have smaller impacts on the simulated requirements than hours with high production. That is, the results reflect that, e.g., a 10 percent hour-ahead forecast error on wind production at 6000 MW in one Hour 14 results in a higher load-following requirement than a 10 percent error on wind production at 600 MW in another Hour 14. Hence, this distribution is reflective of the actual requirements over the season.

The *maximum* hourly values in these figures – the top of the ranges – are analogous to the results that were shown in the 2007 Report, although the simulations conducted in this study have used a different load profile reflecting the different target year (2012 compared to 2010 in the 2007 Report) and include the effect of production, forecast error and variability also for solar production.[55]

As shown in the figures, the maximum seasonal hourly load-following up requirement (for summer 2012) is 3737 MW (Hour 15), which is an 854 MW increase over the requirement estimated for that hour in the 2006 simulation. The maximum seasonal hourly load-following down requirement for 2012 is 3,962 MW (Hour 24), a 597 MW increase over the requirement estimated for that hour in the 2006 simulation. These maximum increases in requirements are almost entirely driven by the additional wind on the system (some further analysis into the relative impact of load, wind and solar is shown in Appendix A-2).

The figures show that the maximum load-following up and down capacity requirements in 2012, and the biggest changes from the 2006 results, are concentrated in the morning and evening ramp hours, as would be expected. The maximums for the top 4 load-following up hours are in hours 8, 14, 15 and 16; the maximums for load-following down are in hours 18, 19, 23 and 24. Notably, the highest average values for load-following requirements in both the upwards and downwards directions are in hours 22-24, corresponding to maximum wind production, showing that it is in these hours that the requirements will increase most substantially overall over the season. This can be seen from the red bars corresponding to those hours in Figure 3-1 and Figure 3-2.

[54] That is, assuming a 90 day season, each of the 100 iterations runs through all hours of the season – day 1, hour 1, day 1, hour 2, … day 2, hour 1, day 2, hour 2, …, day 90, hour 1, hour 2. This results in 100 values for each hour. Of these 100 values, the maximum value is selected. Then all the hour 1s are grouped, as are all the hour 2s, hour 3s and so on. That results in 24 sets of 90 values, since there are 90 hour 1s, 90 hour 2s, etc. The distributions shown here is of those 90 values for each hour.

[55] The range shown in each red arrow is the minimum and maximum of the *highest* hourly seasonal values for each of the 100 iterations in the simulation. The maximum is thus the highest of those values.

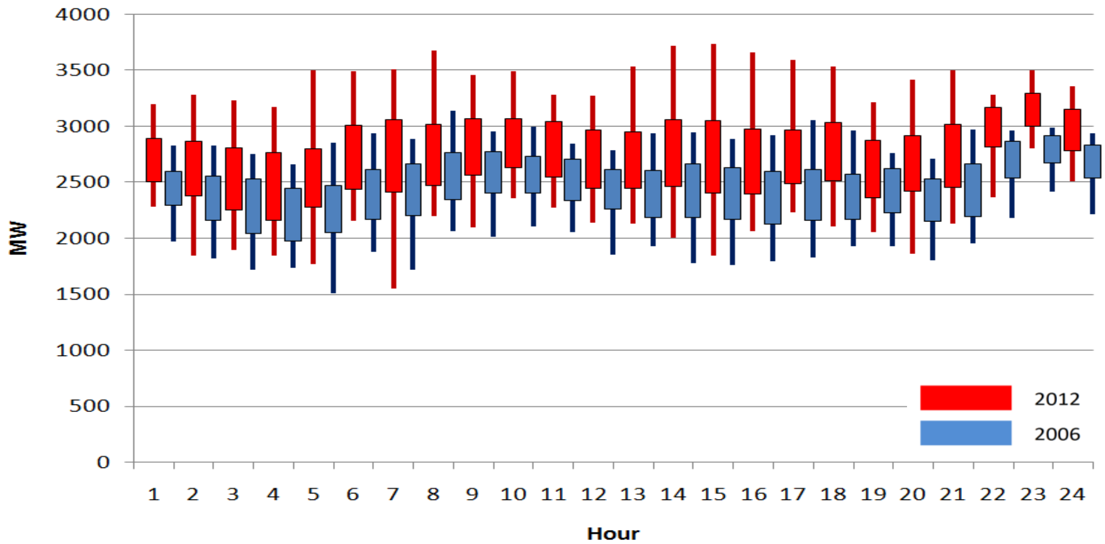


Figure 3-1: Load-following Up Capacity by Hour, Summer (2006 and 2012)

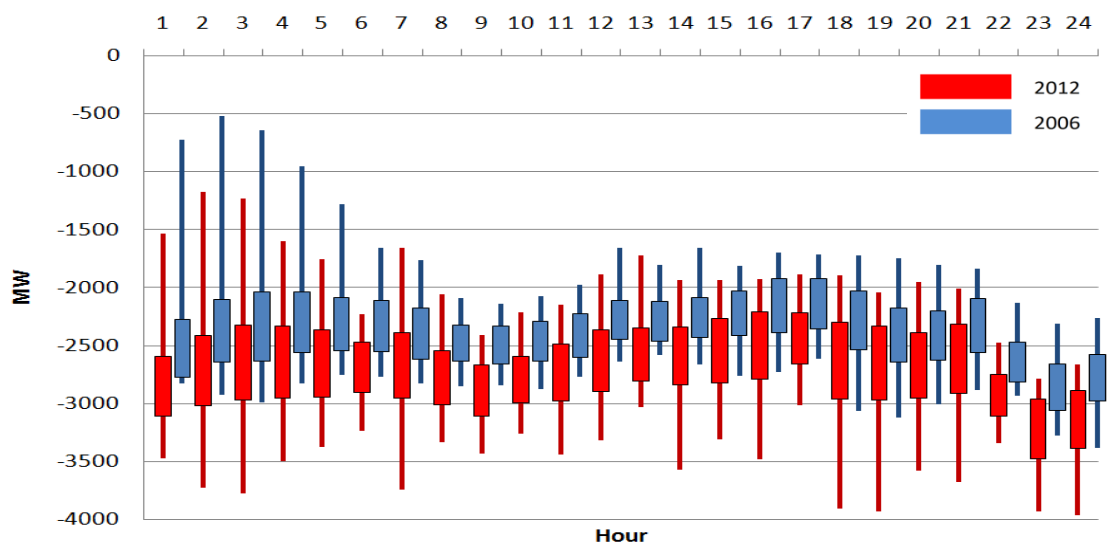


Figure 3-2: Load-following Down Capacity by Hour, Summer (2006 and 2012)

Figure 3-3 and Figure 3-4 show the frequency distribution of the maximum load-following capacity requirements in 2012 and 2006 by MW range and percentage of the total hours in the season.[56] These figures show more explicitly that the highest seasonal load-following capacity requirements are expected to be infrequent, but that the overall increase in this requirement remains significant. For the summer season, the total simulated requirement of load-following up in 2012 (the total MW of the values in the frequency distribution) is about 12 percent greater than the corresponding total for 2006; the simulated requirement for load-following down in 2012 is 14 percent greater than that

[56] This frequency distribution is drawn from the same data shown in Figure 3-1 and 3-2.

for 2006.[57] This provides a measure of the increasing volume of the real-time market between the baseline and the target year.

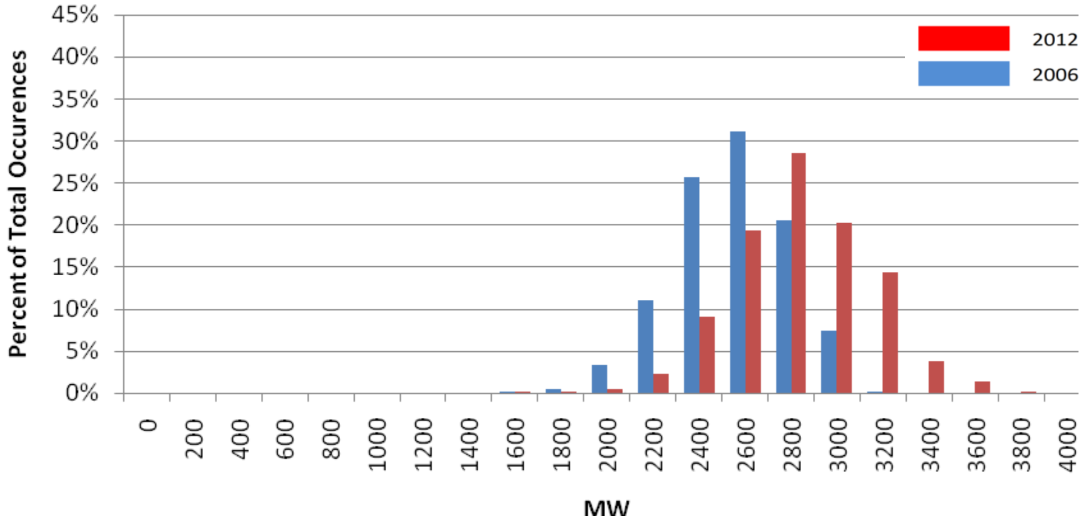


Figure 3-3: Frequency Distribution of Load-following Up Capacity Requirements, Summer (2006 and 2012)

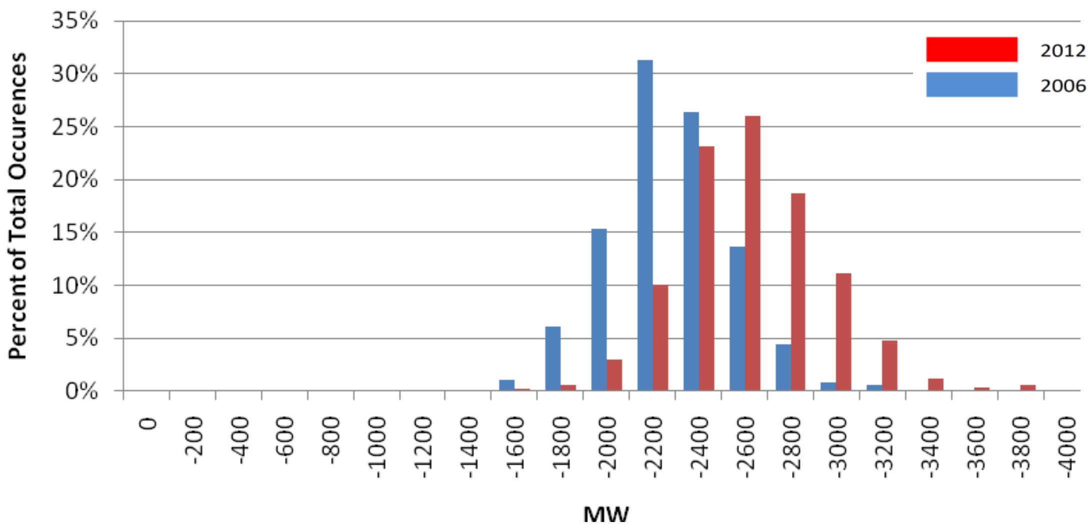


Figure 3-4: Frequency Distribution of Load-following Down Capacity Requirements, Summer (2006 and 2012)

[57] That is, the total MW calculated as "load-following" capacity for each hour in the 2012 simulations divided by the total MW calculated for 2006.

As discussed in Section 2, the simulated load-following *ramp rate* is defined as the maximum increase or decrease in the estimated capacity requirement between any two contiguous 5-minute intervals within the hour being simulated. Figure 3-5 shows that the maximum load-following up ramp rates across the season for the full portfolio are located in the off-peak hours, where they correspond to variability and forecast error in wind production.

Figure 3-6 shows that the maximum requirements in load-following down ramp rate occur between Hour 7 and Hour 10, when solar production ramps up and wind production is decreasing. Again, the actual system net ramp rate can be high in these hours when the wind and solar ramps are not well correlated with the morning load ramp up.

In the high load-following ramp hours, the duration of the ramps may be sustained for a large number of intervals. The statistical methodology tracks duration of the simulated ramp rate using a specialized algorithm (see Section 2).[58] Figures 3-7 and 3-8 show the ramp requirement by minute (MW/min) plotted for the longest number of minute intervals that the algorithm identified in the morning and evening hours, respectively. As shown in Figure 3-7, the upward ramp duration in the morning is required for approximately 30 minutes (as shown on the figure’s x-axis), while the downward ramp will be required for approximately 20 minutes. Resources on dispatch should be able to ramp up at a rate of about 100 MW/min. (as shown on the figure’s x-axis) for most of the 30 minutes. Similarly, in the downward direction, the resources on dispatch should be able to ramp down at a rate of approximately -175 MW/min. for at least 20 minutes. Figure 3-8 can be interpreted similarly for the evening ramps, in which the ramp duration and magnitudes are roughly reversed compared to the morning hours.

[58] Called the “swinging door” algorithm, which tracks and measures sequences of random draws to infer changes in ramp rates and durations.

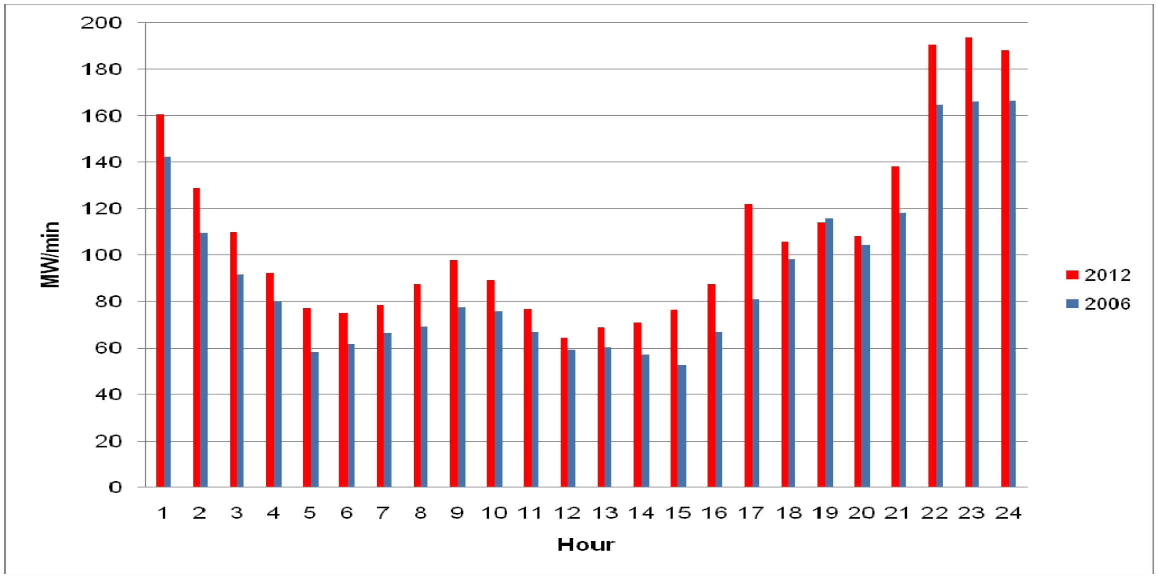


Figure 3-5: Load-following Up Ramp Rate, Summer (2006 and 2012)

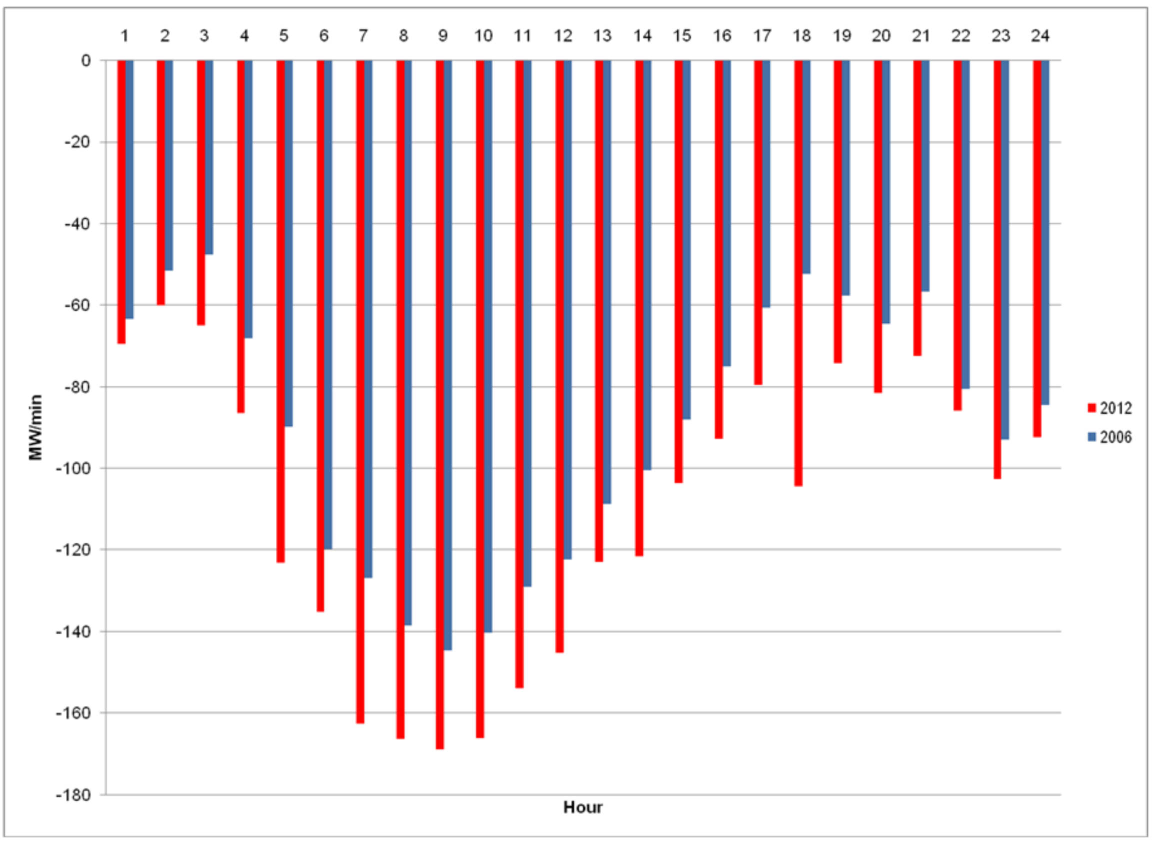


Figure 3-6: Load-following Down Ramp Rate, Summer (2006 and 2012)

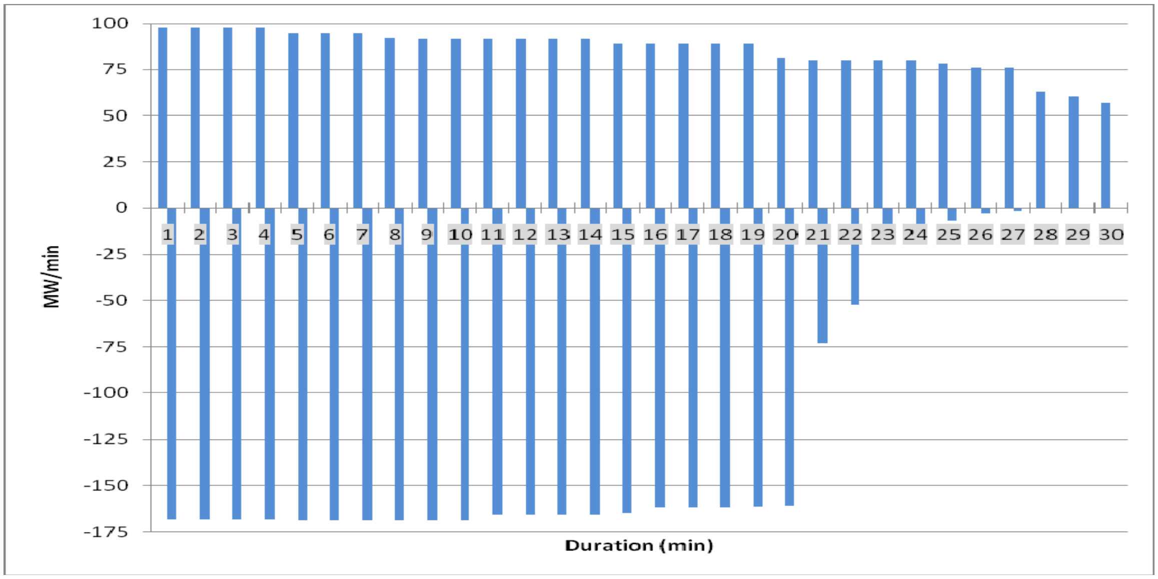


Figure 3-7: Seasonal Load-following Up and Down Ramp Duration for Morning Hours, Summer 2012

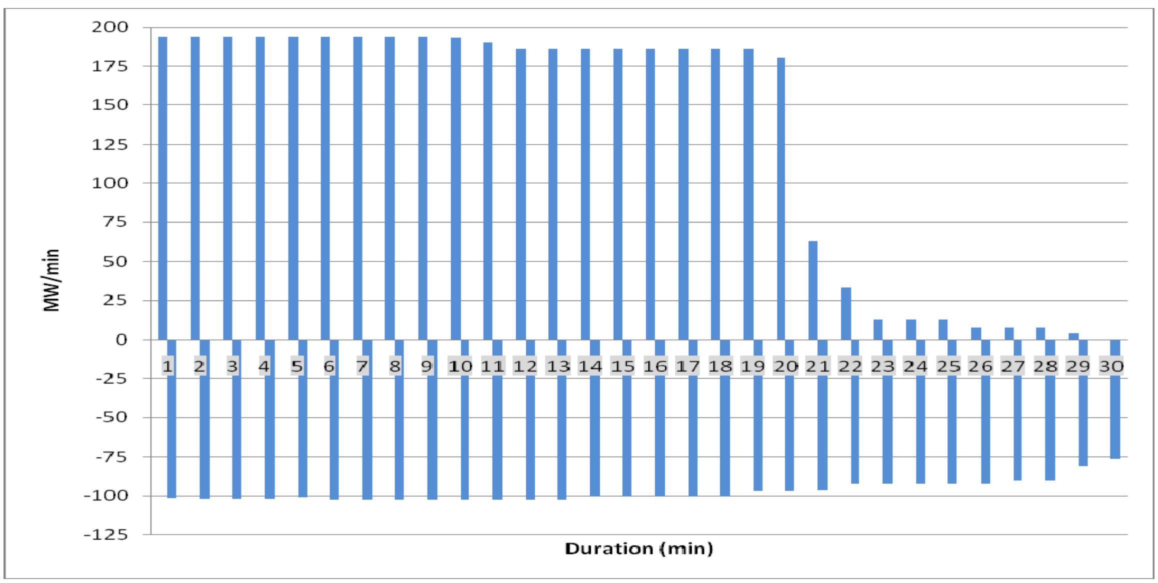


Figure 3-8: Seasonal Load-following Up and Down Ramp Duration for Evening Hours, Summer 2012

In general, the maximum simulated load-following capacity and ramp requirements increase substantially for almost every hour of the day. Section 4 compares the load-following requirements determined here with the historical load-following capability. Section 5 simulates the capability of the fleet to meet the load-following requirements in 2012 under different conditions.

3.4 Regulation Requirements for Summer 2012

This section shows the simulated regulation requirement results for the full 20 percent RPS portfolio assuming all forecast errors (for load, wind and solar) remain within historical results. The results presented here are organized in parallel to the results shown for load-following, with some differences noted. Figures Figure 3-9 and Figure 3-10 show distribution statistics for the set of values that include the *maximum* regulation capacity result for each hour in the season drawn from all 100 iterations of the simulation. As with the load-following results, the hourly bars are a modification of a typical "stock" chart. The black line represents the range (minimum, maximum) of the results and the red box shows the standard deviation. The arrow points towards the maximum of the range. The maximum of the baseline 2006 simulation for each hour is shown in blue.

As with the load-following results, the subset of hours shown in the 2012 result is comprised of the 90 maximum values for each of the 24 hours of the days.[59] Hence, while the distribution of results shown here reflects higher forecast errors drawn across the iterations (although it is also affected by the variability reflected in that hour), it also preserves the actual variable energy resource production profiles such that hours with low (or no) production are on average shown to have smaller impacts on the simulated regulation requirements than hours with high production.[60]

The *maximum* hourly values in these figures – the top of the ranges – are analogous to the results that were shown in the 2007 Report, although the simulations conducted in this study have used a different load profile reflecting the different target year (2012 compared to 2010 in the 2007 Report) and include the effect of production, forecast error and variability also for solar production.

The figures show that similarly to load-following, the incremental regulation capacity requirements are concentrated in the morning and evening ramp hours, as would be expected. The maximums for the top 4 regulation up hourly requirements are in hours 9, 8, 6 and 19; the maximums for regulation down are in hours 15-18. Solar production variability has the strongest effect on the simulated regulation up requirements in the late afternoon hours, while also having a strong effect on the regulation down requirements in Hour 8 (see figures in Appendix A-2). Wind production variability is the predominant driver of the increased requirements in the other hours. In particular, the spike in regulation down requirements in Hour 18 is due to the consistent fast ramp in wind production in that hour found in the underlying wind production data set for 2012.

[59] That is, assuming a 90 day season, each of the 100 iterations runs through all hours of the season – day 1, hour 1, hour 2, …, day 2, hour 1, hour 2, …, day 90, hour 1, hour 2. This results in 100 values for each hour. Of these 100 values, the maximum value is selected. Then all the hour 1s are grouped, as are all the hour 2s, hour 3s and so on. That results in 24 sets of 90 values, since there are 90 hour 1s, 90 hour 2s, etc. The distributions shown here is of those 90 values for each hour.

[60] That is, the regulation results reflect that, e.g., variability on wind production at 6000 MW in one Hour 14 results in a higher regulation requirement than variability on wind production at 600 MW in another Hour 14. Hence, this distribution is reflective of the actual requirements over the season, as modeled.

Notably, the distribution statistics show that not only the maximums for regulation up are in the mid-morning hours, but also the highest averages. These hours correspond to the maximum wind ramp down periods, showing that it is in these hours that the requirements will increase most substantially overall. Similarly, not only the maximums but also the average increase in regulation down requirements take place in the late afternoon hours.

In a few hours of the regulation down results, the simulation with the incremental wind and solar shows a lower maximum result than the 2006 simulation. This result is due to the correlation of wind, solar and load in those hours, which has the effect of lowering the regulation requirement. For example, in the early morning, load is ramping up, while wind is ramping down and solar is ramping up. The net effect can be very little downward requirements in the regulation time frame. However, as noted above, the ISO typically procures a minimum quantity of 300 MW of regulation up and 300 MW of regulation down in the day-ahead time frame to account for uncertainties that are not captured in the simulation.

As noted above, the maximums are not an indication of the change in regulation procurement across all hours and all system conditions. Figures Figure 3-11 and Figure 3-12 show the frequency distribution of the maximum regulation capacity requirements in 2012 and 2006 by MW range and percentage of the total hours in the season.[61] These figures show more explicitly that the highest seasonal regulation capacity requirements are expected to be infrequent, but that the overall increase in this requirement remains significant. For the summer season, the total simulated requirement of regulation up in 2012 (the total MW of the values plotted in the frequency distribution for 2012) is approximately 37 percent greater than the corresponding total for 2006; the simulated requirement for regulation down in 2012 is only 11 percent greater than that for 2006, and much of that increase is concentrated in one or two late afternoon hours.[62] This provides a measure of the possible increasing aggregate procurement of regulation between the baseline and the target year.

[61] This frequency distribution is drawn from the same data shown in Figure 3-9 and Figure 3-10.

[62] That is, the total MW calculated as "load-following" capacity in the 2012 simulations divided by the total MW calculated for 2006.

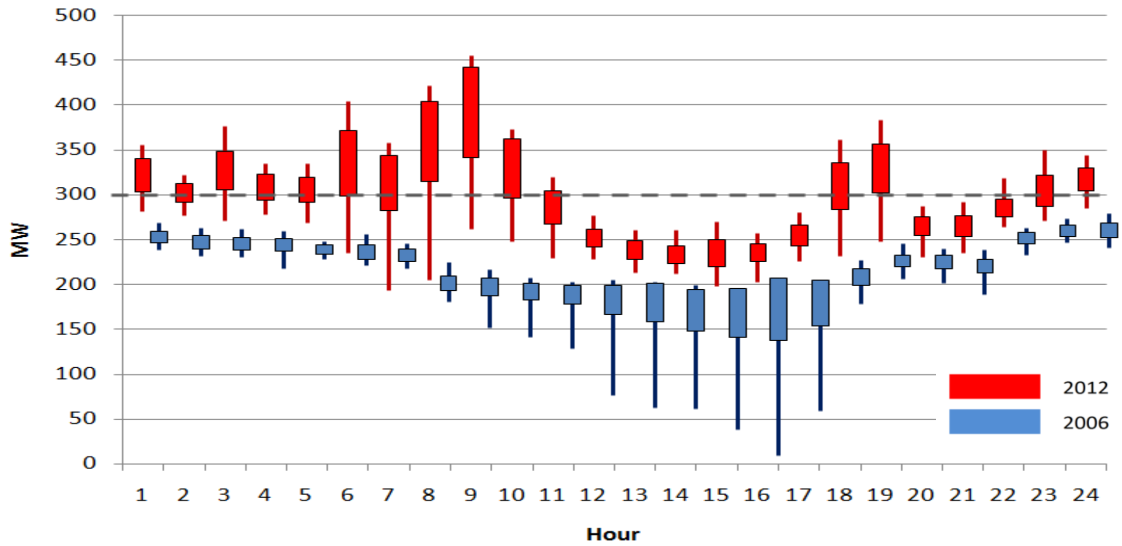


Figure 3-9: Regulation Up Capacity Requirement by Hour, Summer (2006 and 2012)

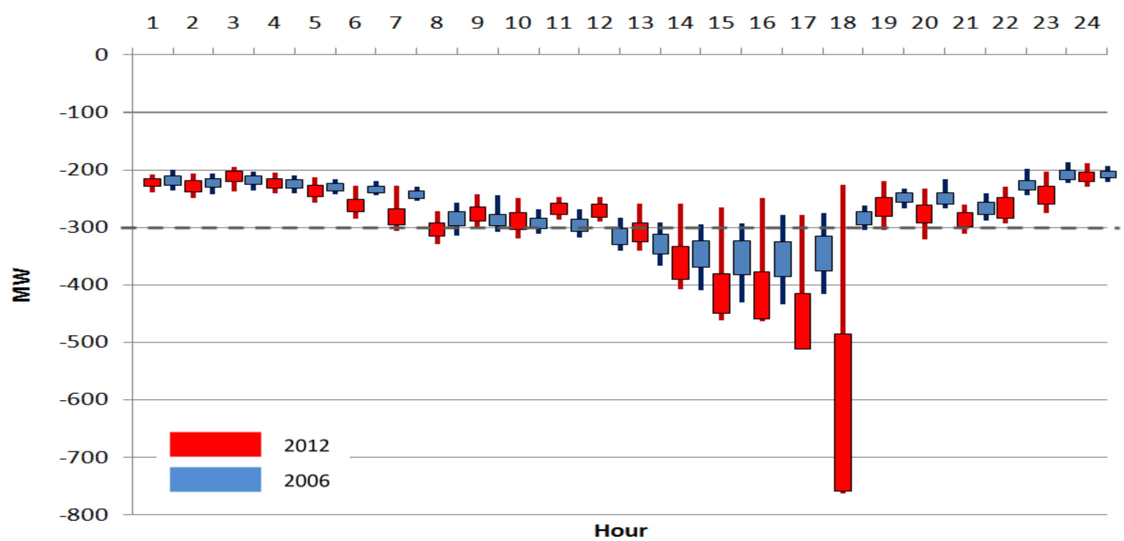


Figure 3-10: Regulation Down Capacity Requirement by Hour, Summer (2006 and 2012)

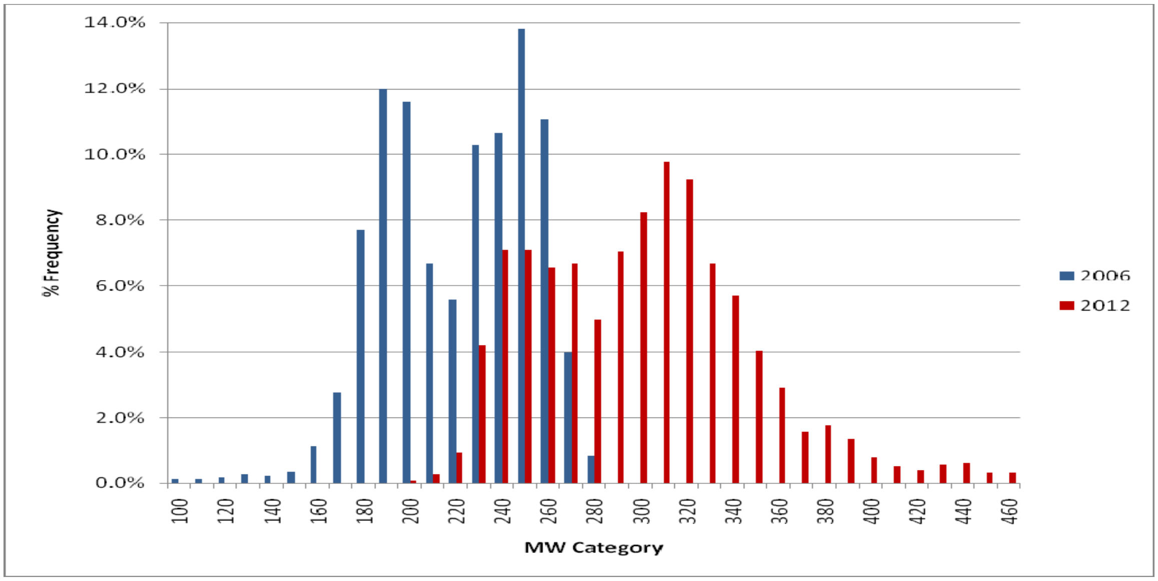


Figure 3-11: Frequency Distribution of Regulation Up Capacity Requirements, Summer (2006 and 2012)

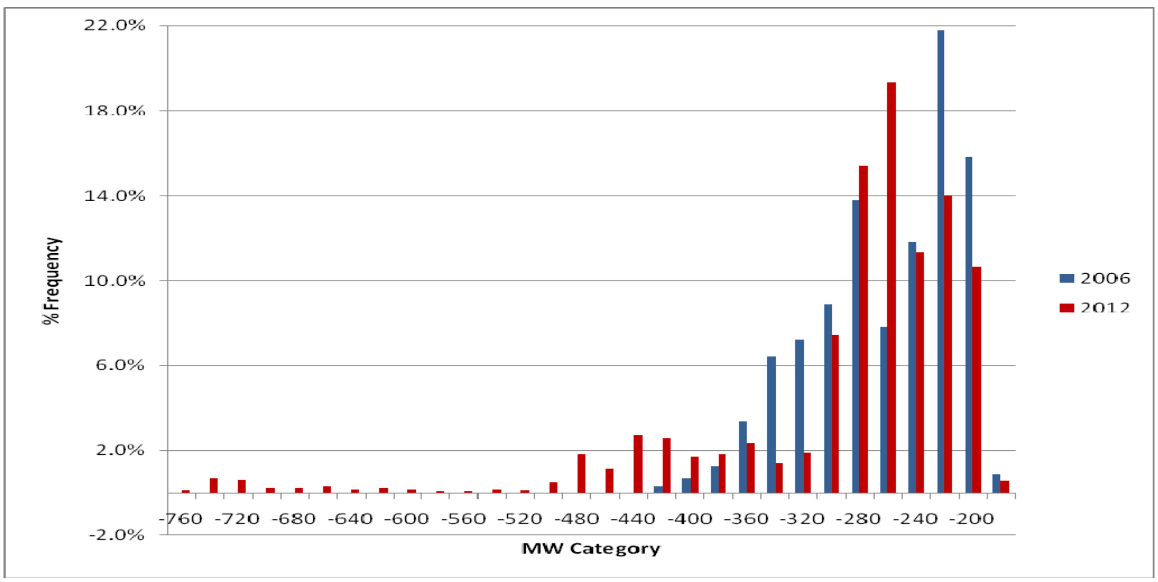


Figure 3-12: Frequency Distribution of Regulation Down Capacity Requirements, Summer (2006 and 2012)

As discussed in Section 2, the simulated regulation *ramp rate* is defined as the largest minute-to-minute change within a 5-minute dispatch interval. Figure 3-13 shows that the maximum regulation up ramp rates across the season (for the full portfolio) are located in the afternoon hours. Figure 3-14 shows that the maximum requirements in regulation down ramp rate occur between Hour 6 and Hour 9, when solar production ramps up and wind production is decreasing, and again in the late afternoon in Hours 16 to 18.

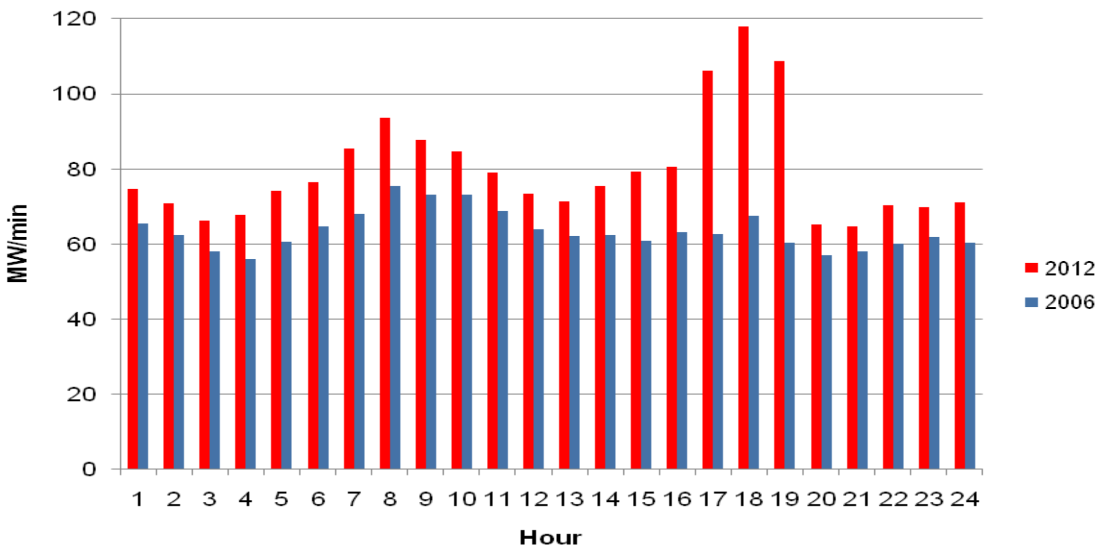


Figure 3-13: Summer Regulation Up Ramp Rate by Hour (2006 and 2012

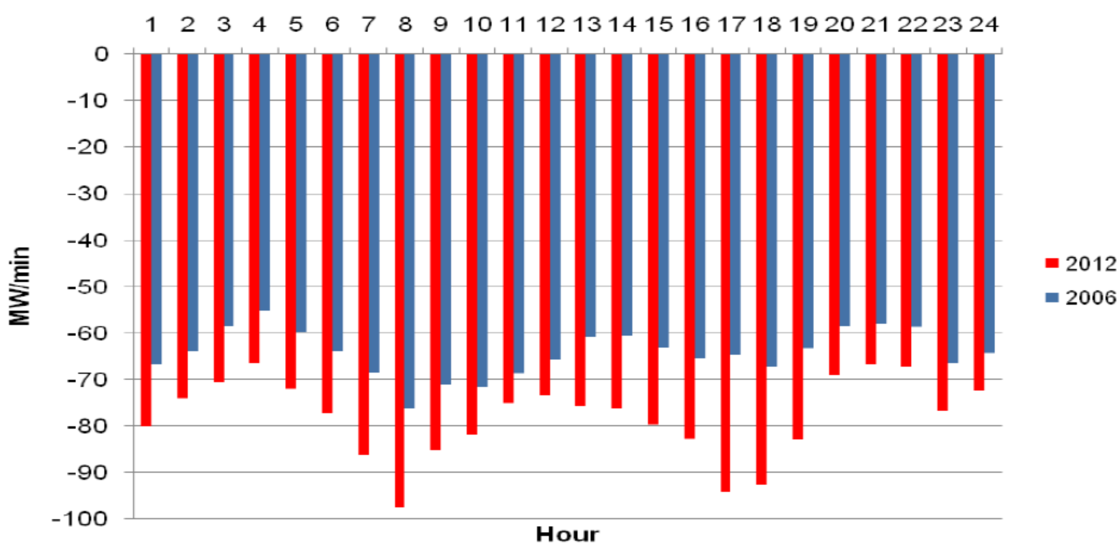


Figure 3-14: Summer Regulation Down Ramp Rate by Hour: 2006 and 2012

4 Analysis of Historical Fleet Capability

This section presents analysis of selected measures of generation fleet capability for the period from April 1, 2009 to June 30, 2010. The objective is to provide insight into the ability of the current generation fleet to provide sufficient regulation and load-following capacity to meet the operational requirements under 20 percent RPS determined in Section 3. Section 4.1 provides a summary of the findings of this analysis. Section 4.2 presents an inventory of the physical characteristics of the ISO generation fleet. Section 4.3 compares historical, seasonal load-following capacity with the corresponding requirements discussed in Section 3.3. Similarly, Section 4.4 compares historical, seasonal bid-in and committed regulation capacity with the additional regulation capacity requirements discussed in Section 3.4.

4.1 Summary of Findings

- The historical 5-minute load-following capability of the generation fleet, defined as the upward and downward ramp capability in each 5-minute interval, has been measured from April 1, 2009, to June 30, 2010. This analysis shows that the fleet inherently has the 5-minute load-following capability required under 20 percent RPS. However, much of the downward capability is currently provided to the ISO with limited inflexibly due to submitted self-schedules. To successfully integrate 20 percent RPS, the level of self-schedules will have to decrease.

- The ISO regulation markets have procured levels of regulation up and regulation down since April 1, 2009, in the range of 600-700 MW in each hour of the operating day, with these high procurements largely taking place during the first month of market implementation to ensure reliability. These procurement levels provide one test of the ISO's ability to meet the higher regulation requirements that could be experienced at the 20 percent RPS.

- In addition, the 5-minute regulation capability of the generation resources bid-in and committed in each hour of the day since April 1, 2009, has been measured and shown potentially to be the source in most hours of sufficient capability over and above the calculated additional regulation requirements under 20 percent RPS.

4.2 Physical Characteristics of the Existing Generation Fleet

Table 2.7 in Section 2 provides a breakdown of the generation fleet capacity organized by ramp rate segment (MW/min). For example, there is a total of 21,003 MW of capacity under the ISO's control with a ramp rate of 5 to 10 MW/min. Individual generation units will have different ramp rates over their range of output, so may have capacity in several of the columns. The table also divides the generation fleet into once-through cooling (OTC) units and those that are not once-through cooling units. Although replacement and repowering of once-through cooling units will begin after the study date of 2012, the table helps to characterize the flexibility characteristics of those units, which must be considered in the context of renewable integration capabilities.

4.3 Load-following Capability

Physical characteristics give important insight into fleet capabilities, but operational flexibility is a function of which units are committed in each time interval and also their availability for dispatch. Generation that is self-scheduled at levels greater than a resource's physical minimum operating level (Pmin) through the ISO markets is essentially unavailable to ISO dispatchers within the hour except through non-market dispatch instructions that can distort market prices. To gain insight into the historical upward and downward capability of the committed resources, the ISO has examined the resources on the system from April 1, 2009 - June 30, 2010, to quantify both their load-following and regulation capability.

This section discusses load-following capability for the summer season. The examination for the remaining seasons can be found in Appendix B. Figure 4-1 provides the 5-minute Load-following up capability, measured as the maximum dispatch that can be achieved in the upward direction based on submitted energy bids within 5 minutes, subject to the ramp rates and other operational constraints of the dispatched units. Figure 4-2 provides the 5-minute load-following down capability, limited by self-schedule, measured as the maximum dispatch that can be achieved in the downward direction within 5 minutes, subject to the ramp rates and other operational constraints of the dispatched units. As used throughout this report, the stock charts show the range and standard deviation of the upward and downward 5-minute load-following capability. The upper and lower dispatch limit are internally calculated and reflect a resource's ramping capability, operating limits, derates, regulation limits (when on regulation). The load-following capability is a measure of the capability to follow load from one 5-minute dispatch to the next.

The results show that the ISO dispatch in recent months appears on average to meet the expected load-following upwards capability for even the extreme ramps reflected in the statistical simulations. The simulated *maximum* load-following up ramp rate for summer in 2012 as shown in Table 3-2 was 194 MW/min, which is 980 MW/5 min. From Figure 3-5 in Section 3, it can be observed that the high ramps are during hours 22 through 24. The historical summer 5-minute load-following capability in 2009-2010 is shown in Figure 4-1. Historically, anywhere between 0 and 3000MW of load-following capacity is available during these hours with an average of approximately 1200MW. Therefore, on an average, based on committed resources with existing solution constraint, sufficient 5-minute load-following capacity would be available to meet the requirements. The production simulation discussed in Section 5 tests the load-following capability of the system for a few selected days in the future.

The results for downwards ramping appear more problematic. The simulated maximum load-following down ramp rate for summer in 2012 was -169 MW/min as shown in Table 3-2, which is -845 MW/5 min. These high downwards ramps are often in the mid-morning hours as shown in Figure 3.6 in Section 3. As discussed before, Figure 4-2 shows the summer 5-minute load-following down capability of only the units that are dispatchable. Figure 4-3 shows the summer 5-minute load-following down capability of thermal units, both self-scheduled and dispatchable. The 5-minute downward ramp capability without the self-scheduled units, ranges from 0 to -2000MW. During some hours, for example, hour 7 in Figure 4-2, the average 5-minute downward capacity could be as low as -500 MW, which is less that the requirement of -845 MW. The 5-minute downward ramp capability is much higher if the contribution from self-scheduled units is counted. This shows the need for the ISO to pursue incentives or mechanisms to reduce the level of self-scheduled resources and/or increase the operational flexibility of other dispatchable resources. The production simulation discussed in Section 5 will specifically test the downward load-following capability of the system for a few selected days when down ramp is expected to be a problem.

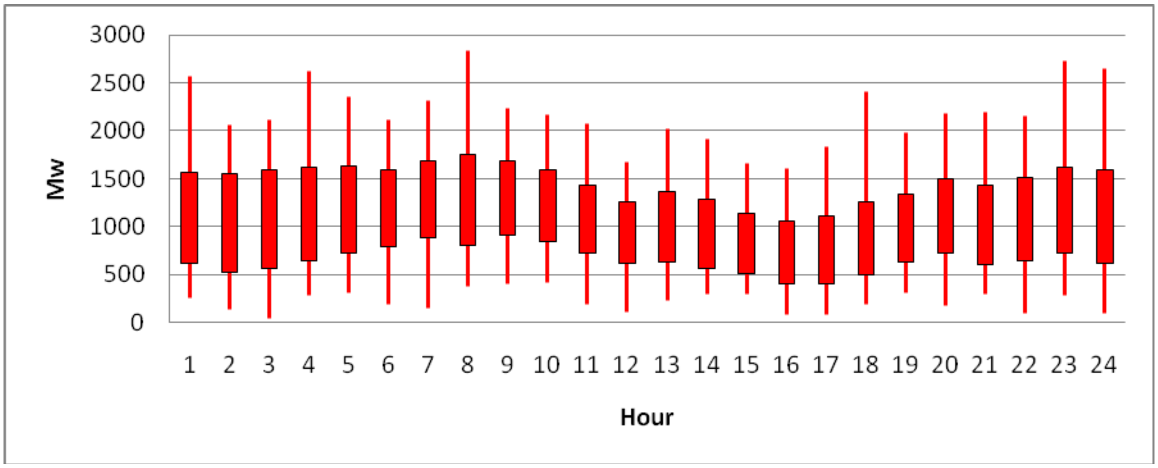


Figure 4-1:Summer Upward 5-minute Capability, 2009 and June 2010

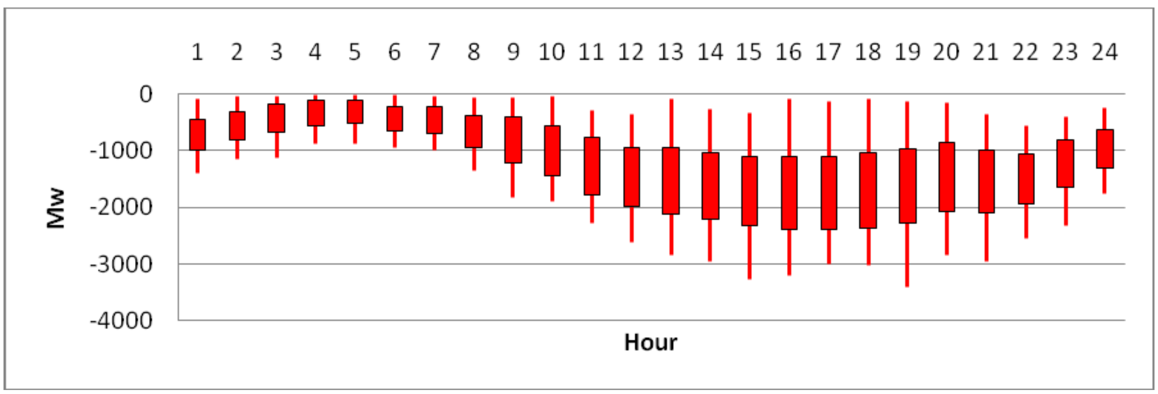


Figure 4-2: Summer Downward 5-minute Capability, limited by self-schedules, 2009 and June 2010

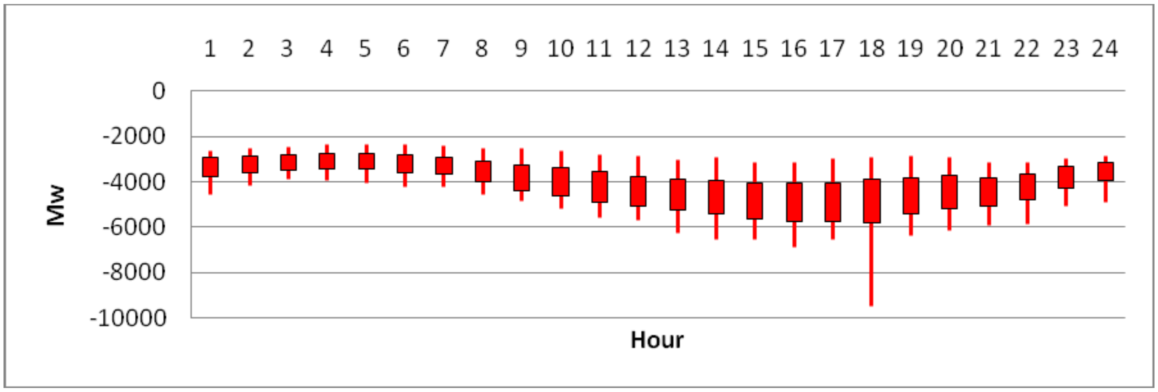


Figure 4-3:Summer Downward 5-minute Capability of Thermal Units, not limited by self-schedules, 2009 and June 2010

The above results show that the ISO dispatch in recent months appears, for the majority of intervals analyzed, to be able to meet the load-following up requirements simulated for 20 percent RPS within 20 minutes or less.[63] This is simply due to the ramp capacity remaining on units not dispatched to their maximum operating levels, and not to any preparations made by the ISO to address renewable integration.

A further measure of the frequency of downward ramp constraints and overgeneration is the occurrence of negative prices. Table 4.1 shows the number of real time 5-minute dispatch intervals which all Load Aggregation Points (LAP) had negative prices since April 1, 2009 (3,727 intervals in total). The chart shows that the highest frequency is concentrated in the early and mid-morning hours with heaviest occurrence in the spring months.

[63] For example, if the 3,737 MW maximum load-following up requirement determined in Section 3 has to be met within 20 minutes of the start of the hour, the results suggest that in most hours, the current system ramp could on average in most hours sustain 1000 MW/5-minutes or more, meaning that the requirement could be met and slightly exceeded in 4 such intervals.

Table 4.1: Frequency of Negative Prices in Real-Time Dispatch Intervals by Month and Hour, April 1, 2009 to June 30, 2010

	April 1, 2009-March 31, 2010												April 1, 2010-June 30, 2010		
	Apr (Out of 360int/ hr)	May (Out of 372int/ hr)	Jun (Out of 360int/ hr)	Jul (Out of 372int/ hr)	Aug (Out of 372int/ hr)	Sep (Out of 360int/ hr)	Oct (Out of 372int/ hr)	Nov (Out of 360int/ hr)	Dec (Out of 372int/ hr)	Jan (Out of 372int/ hr)	Feb (Out of 336int/ hr)	Mar (Out of 372int/ hr)	Apr (Out of 360int/ hr)	May (Out of 372int/ hr)	Jun (Out of 360int/ hr)
1	69	40	31	19	6	2	2	4	13	2	3	2	1	5	33
2	26	34	37	14	18	7	0	5	7	10	0	7	1	0	20
3	26	35	85	41	11	19	1	28	9	9	14	10	10	5	20
4	71	64	105	78	22	13	2	8	9	25	23	5	27	4	20
5	58	65	65	72	13	19	1	8	8	7	16	10	22	56	80
6	47	66	67	14	6	8	0	4	2	1	1	10	14	42	66
7	29	75	98	76	7	15	0	7	6	6	0	2	2	61	81
8	74	20	36	21	11	9	3	6	1	0	0	0	5	18	52
9	9	17	33	29	7	2	0	0	0	0	0	0	0	5	49
10	2	14	12	9	3	0	0	0	0	0	0	0	0	6	24
11	15	12	1	0	0	1	0	0	0	0	0	0	0	0	1
12	18	9	0	0	0	0	0	0	0	0	0	0	0	0	3
13	10	6	8	0	0	0	0	0	0	0	0	0	0	0	10
14	6	4	0	0	0	0	0	0	0	0	0	0	0	0	5
15	9	15	0	0	0	0	0	2	0	0	0	0	0	0	0
16	7	12	10	0	0	3	0	1	0	0	0	0	0	2	0
17	13	2	6	0	0	0	0	0	0	0	0	0	0	2	0
18	16	12	11	0	0	0	0	0	0	0	0	0	1	0	0
19	37	3	17	0	0	0	0	0	0	0	0	1	1	2	2
20	29	1	11	0	0	0	0	0	0	0	0	0	4	0	0
21	3	0	4	0	0	0	0	0	0	0	0	0	0	0	0
22	16	5	1	0	0	1	0	0	0	0	0	0	0	0	0
23	77	24	25	3	1	0	0	1	1	0	0	0	0	3	6
24	42	63	36	16	4	4	2	4	7	7	1	0	1	10	11

4.4 Regulation Capability

As one step to evaluate the ability to meet the sustained higher regulation requirements identified in Section 3, the ISO has examined the regulation capability of the fleet as well as regulation procurement quantities and the ranges of regulation capable units under dispatch since the start of the redesigned wholesale markets in April 2009. As shown in Table 4.2, the ISO has substantial regulation capacity, with almost 20,000 MW of regulation certified capacity and over 5,000 MW with regulation ramp rates of 20 MW/min or higher. Regulation deficiency when it occurs is thus primarily due to system conditions that restrict regulation capable units from being on dispatch. Historically, the ISO has been short of regulation down at times, especially during high hydro conditions such as occurred in 2006, which could be exacerbated with additional wind on the system.[64]

Table 4.2: Regulation Certified Capacity of the ISO Generation Fleet by Ramp Rate, 2010

Generation Type		Regulation Ramp Rates (RR) (MW/min) by Category				
		1 ≤ RR < 5	5 ≤ RR < 10	10 ≤ RR < 20	20 ≤ RR	Total MW
Non-OTC Units	Combined Cycle	719	1693	2171	347	4930
	Dynamic Schedule				775	775
	Gas Turbine	20	20	159		199
	Hydro	319	1020	891	1880	4110
	Other				4	4
	Pump/Storage				969	969
	Steam	316	100			416
	Not specified				525	525
Non-OTC Unit Total		1374	2833	3221	4500	11928
OTC units	Combined Cycle		370			370
	Steam	2442	3599	500	1060	7601
OTC Unit total		2442	3969	500	1060	7971
All Units Total		3816	6802	3721	5560	19899

Note: Some capacity numbers are rounded

Given the significant changes in market optimization and bidding incentives inherent in the redesigned markets, the ISO determined not to examine regulation procurement and market conditions prior to April 2009.[65] Since that date, while system conditions have not corresponded to the prior historical periods in which ancillary service bids were insufficient, the ISO has procured regulation up and regulation down quantities above the historical norm of 350 MW for the first few months of the redesigned market to ensure reliability of system operations. This has provided one natural test of the markets' ability

[64] Performance of the regulation down markets in the 2006 high hydro conditions is discussed in California ISO, Department of Market Monitoring, *Annual Report, Market Issues and Performance, 2006*, Chapter 4. Available at http://www.caiso.com/1b7e/1b7e71dc36130.html.

[65] The ISO market now procures all ancillary service requirements in the day-ahead market, where the market model simultaneously co-optimizes offers for energy, regulation and operating reserves. This procedure allows for the most efficient selection of bid-in generation capability to meet market and reliability requirements.

to procure higher levels of regulation capacity in all hours of the day, albeit under the system conditions in April 2009. Regulation procurement has been reduced in more recent months and is currently procured on a variable basis throughout the operating day, reflecting the impact of system conditions on regulation needs. Figure 4-4 shows that the ISO has procured 400 MW or more of both regulation up and regulation down for over 2500 hours from April 1, 2009 – June 30, 2010. Moreover, the maximum MW procurements of 600 MW or more took place in every hour of the operating day, confirming that at least under the conditions of that period, the market could mobilize as much regulation as the operational simulations of 20 percent RPS.

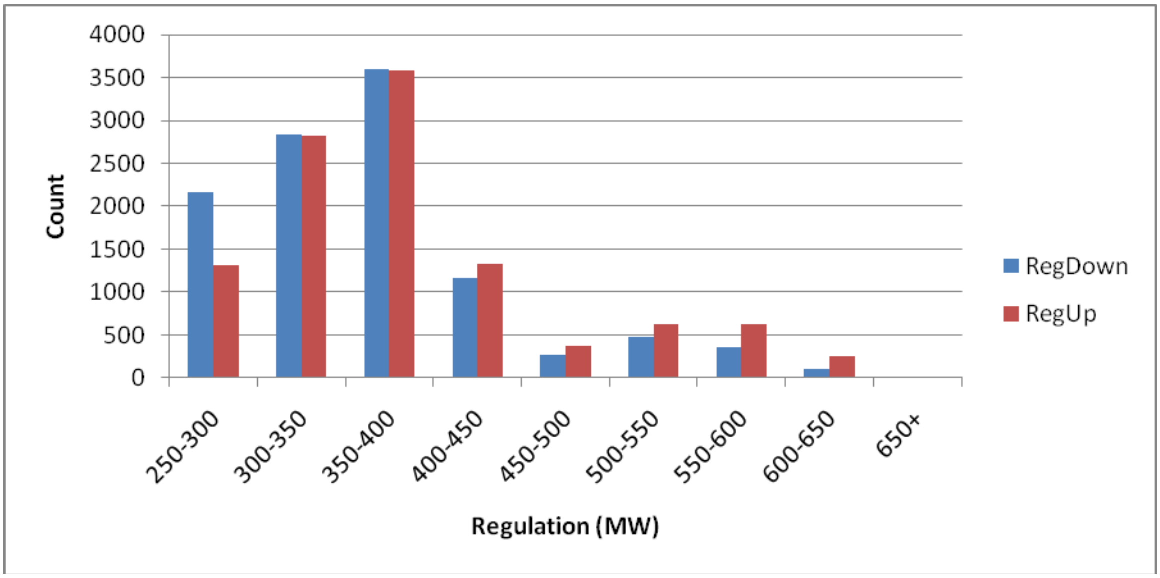


Figure 4-4: Frequency of Regulation procurement by MW (4/1/09 to 6/30/10)

Figure 4-5 and Figure 4-6 show the historical regulation up and down procurement. The values shown are the maximum of the day-ahead and real-time regulation procurements. These figures show that the ISO has been procuring at least 300 MW of regulation during all hours.

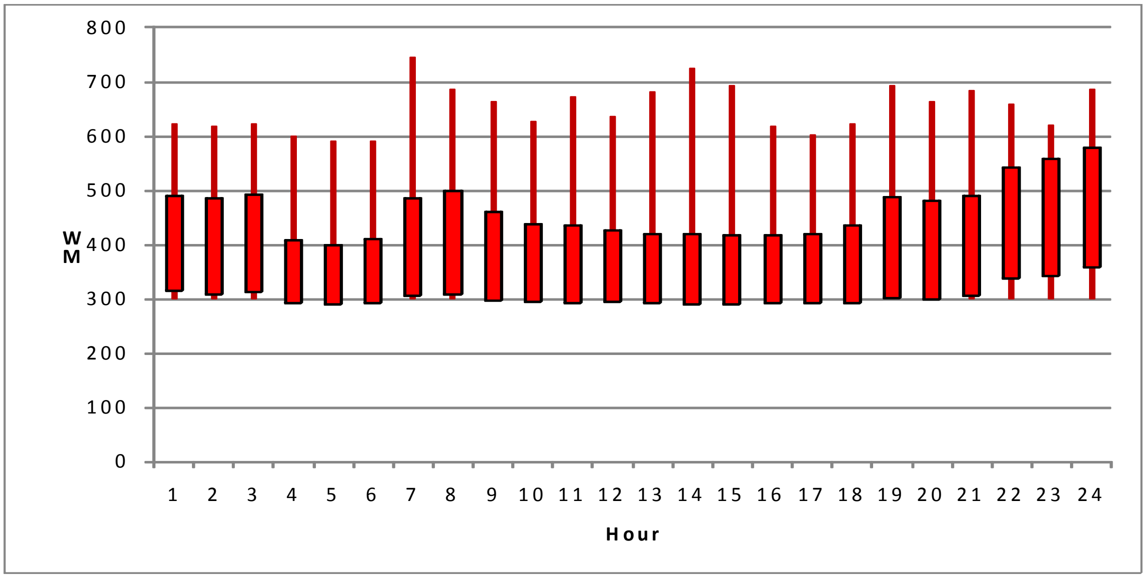


Figure 4-5: Regulation Up Procurement (Max of DA and RTPD Cleared Values)

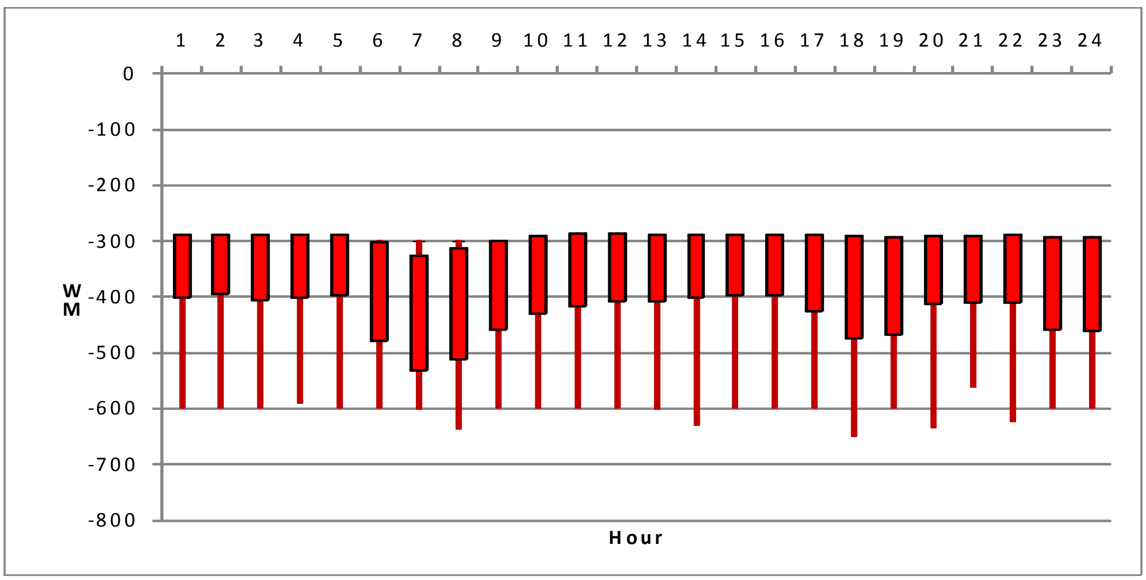


Figure 4-6: Regulation Down Procurement (Max of DA and RTPD Cleared Values)

Moreover, additional analysis of generation that bid into the regulation market, and was committed and dispatched in energy (i.e., on-line) but not necessarily selected to provide regulation, shows that there is a large reservoir of regulation certified capacity available at all hours of the day. When this on-line capacity is constrained to its 5-minute regulation ramp capacity (using the unit-specific regulation ramp rates shown in Table 4.2) there is typically potential coverage of between 1,000 – 2,000 MW of regulation up and regulation down requirement in that 5-minute interval, *if* all such on-line units could provide regulation and do so without creating overgeneration conditions.[66] Moreover, the measurements do not reflect the operational limitations of bid-in capacity due to resource awards of energy or other ancillary services.

This measurement is shown for the summer months in Figures 4-7 and 4-8 and for all seasons in Appendix B. However, particularly in spring and summer, this measure of potential regulation capacity falls below 1000 MW and close to 500 MW in some early morning hours, showing that capability does tighten reflecting fewer regulation capable units on-line.

The combination of the inventory of regulation capacity and ramp rates, the record of sustained regulation procurement at up to 600 MW of regulation up and regulation down, and the empirical analysis of on-line regulation ramp capability suggest that the ISO can meet the higher regulation requirements forecast for 20 percent renewable energy. A further test of the ability of the unit commitment and dispatch to meet the higher regulation requirements is conducted using production simulation that reserves such capacity, as discussed in Section 5. That analysis highlights the potential constraint on regulation down during spring high hydro, light load conditions.

[66] The ISO actually procures regulation based on the resource's 10-minute regulating ramp range. However, this measurement was conducted on a 5-minute basis to provide comparison with the operational simulation results in Section 3. Clearly, if the measurement was for 10-minute ramps, the capability shown here would be roughly doubled.

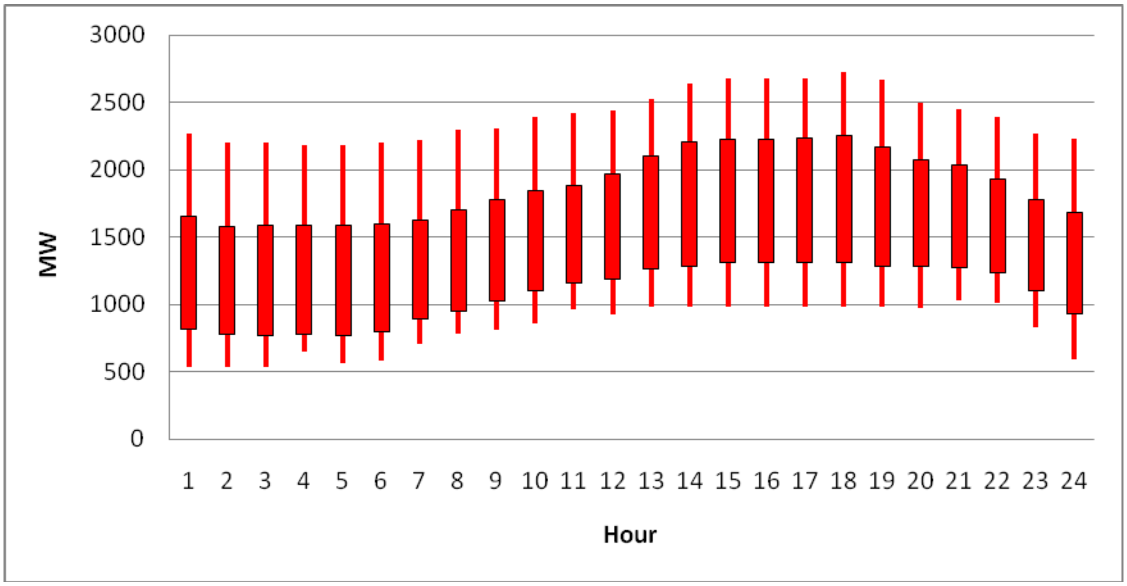


Figure 4-7: Regulation Up 5-Minute Ramp Capability of Bid-In Capacity (MW) by Dispatched Resources, Summer 2009, 2010

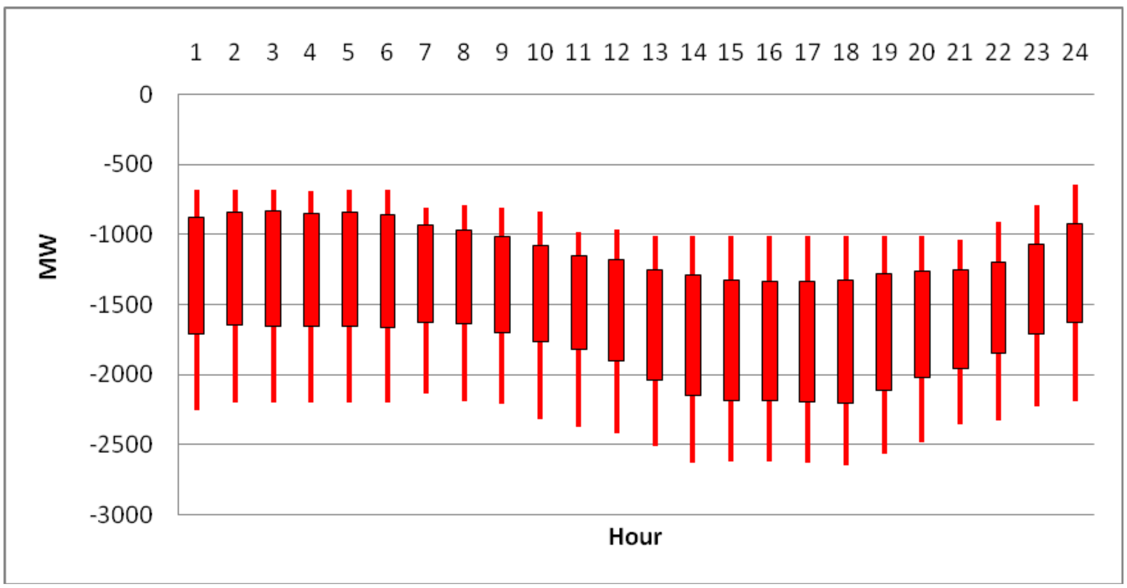


Figure 4-8: Regulation Down 5-Minute Ramp Capability of Bid-In Capacity (MW) by Dispatched Resources, Summer 2009, 2010

5 Analysis of Operational Capability under 20 percent RPS

This section presents the results of the production simulation modeling of the integration of 20 percent renewable energy. Section 5.1 provides a high-level summary of the findings. Sections 5.2 and 5.3 discuss the analysis of load-following and overgeneration impacts, respectively. Section 5.4 provides certain measures of changes in the operation of the thermal generation fleet (e.g., number of starts) as well as preliminary estimates of changes in energy market revenues by unit type.

5.1 Summary of Findings

- Production simulation results suggest that shortages in load-following down capability will result in less than 0.02 percent of renewable energy (approx. 10 GWh) potentially needing to be curtailed. No significant shortages of load-following up or regulation were found.
- Overgeneration was found to be directly correlated to the amount of non-dispatchable generation in the system. Overgeneration, under the worst-case scenario, which assumes no load growth between 2006 and 2012, was 0.32 percent (150 GWh) of annual energy from renewable resources. There is potential to further relieve these instances of overgeneration by increasing the commitment of dispatchable resources in place of inflexible resources, such as firm imports.
- With the 20 percent RPS, dispatchable generators will start and stop more frequently. In particular, combined cycle generators' starts increase by 35 percent. Also, the energy from the combined cycle units decreases by roughly 9 percent with more reduction occurring during off-peak hours with wind generation, indicating that there will be more cycling in the dispatchable fleet.
- The energy market revenues for all dispatchable thermal units were substantially lower by 2012 due to the compounding effect of lower capacity factors and suppressed energy prices due to the influx of renewable energy.

5.2 Load-following and Regulation Impacts

In general, variability in wind and solar generation impacts the regulation and load-following *requirements*, while uncertainty in their generation impacts the regulation and load-following *capability* of the system. Uncertainty in generation may lead to a unit commitment with inadequate regulation and load-following capability. The shortage of regulation and load-following capability may have an impact on Area Control Error (ACE), and if sustained, result in a CPS2 violation. Under extreme cases, the lack of regulation and load-following down capability might require curtailment of generation to resolve the problem.

The stochastic, sequential simulation methodology discussed in section 2.5.2 was used to evaluate the capability of the future system to meet the operational requirements with 20 percent renewable generation. The data and assumptions for the production simulation are discussed in Section 2.5.1. As summarized in Table 2.6, certain generation resources were assumed to be non-dispatchable in the production simulation. The generation profiles for these units, which included, Biomass, geothermal, QFs, hydro, and Imports, were based on either 2006 or 2007 actual operations as described in Section 2.5.1. It should be noted that the entire conventional gas fleet was assumed to be dispatchable in the production simulation. In other words, self-scheduling was not modeled in this analysis. The derivation of the generation profiles for variable energy resources and their day-ahead and hour-ahead forecasts is described in Section 2.5.2.1.

The simulations were targeted at selected days to examine the impact on load-following and regulation.[67] The procedure used for identifying interesting days for real-time simulations is described in Appendix C-1. This methodology identified a number of days in May 2012 with both high upward and downward load-following requirements as candidates for detailed real-time analysis. Table 5.1 shows the days selected for the sequential simulation, as well as the system conditions for each day. This section presents the results of the detailed analyses performed for two of the selected days (May 28, 2012 and May 17, 2012). The results for the remaining days are included as Appendix C.7.

Table 5.1: Characterization of System Conditions for the Days selected for Production Simulation

Date	Period	Load*	Non-Dispatchable Generation	Renewable Generation	Dispatchable Generation
May 28, 2012	6 a.m. – 10 a.m.	Ramp up	High import, High hydro	Solar ramp up, low wind	Low
May 27, 2012	6 a.m. – 10 a.m.	Ramp up	High import, High hydro	Solar ramp up, wind ramp down	Low
May 24, 2012	1 p.m.	High	High import, High hydro	Solar ramp down, wind ramp up	High
May 16, 2012	9 p.m.	High, ramping down	High import, High hydro	Solar very low, wind high	High
May 17, 2012	9 p.m.	High, ramping down	High import, High hydro	Solar very low, wind high	High

[67] It should be noted that the capability of the fleet to provide the regulation requirements determined in the operation analysis is studied using production simulation. However, this analysis does not attempt to identify the sufficiency of the regulation requirement since this would require sub-5-minute simulations that are beyond the scope of this analysis.

5.2.1 Load-following Capability under Low Dispatchability Conditions

Table 5.1 shows the simulated system condition for May 28, 2012. The screening process showed the need for high load-following down requirement on this day. This day also had very limited dispatchable generation online during the low load periods in the morning. This was due to a number of reasons: high hydro and imports from neighboring regions and high wind generation in the morning. This day was also characterized by a rapid increase in solar generation between 5.00 a.m. and 8.00 a.m.[68] Figure 5-1 shows the load (black line) and non-dispatchable generation[69] (red line) and the components of the non-dispatchable generation. The separation between the load and the non-dispatchable generation in Figure 5-1 is the amount of dispatchable generation available for load-following and regulation. Very few dispatchable resources are online during the morning hours, as is evident from the figure.

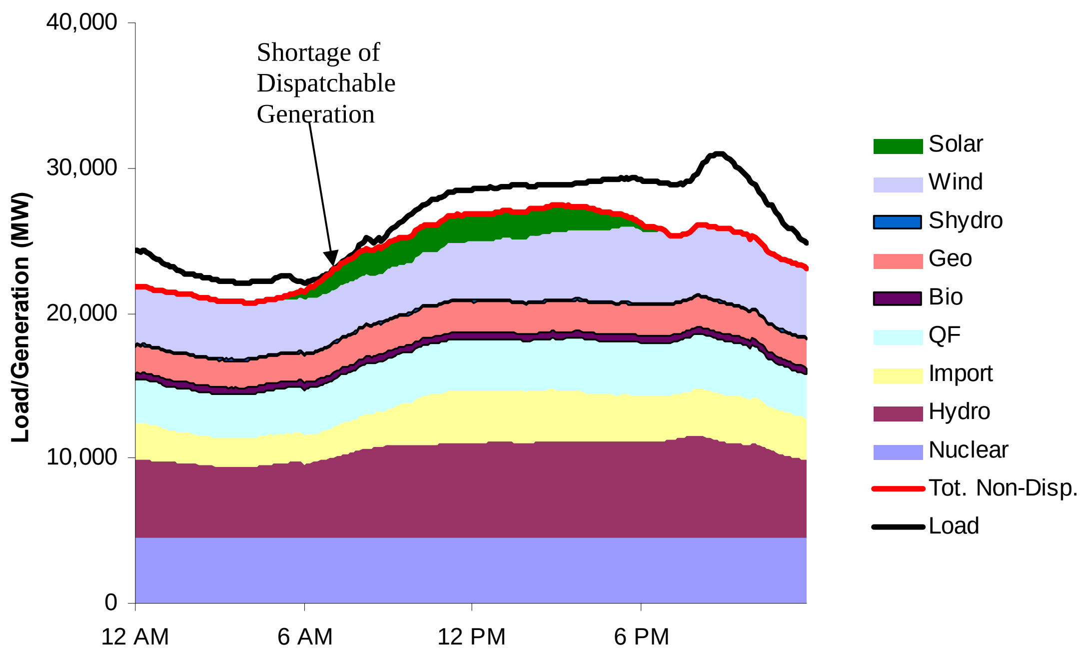


Figure 5-1: Load and Non-dispatchable Generation on May 28, 2010

Figure 5-2 shows the simulated 5-minute load-following up and down capabilities from dispatchable generators for May 28th, 2012. This is the capability of the dispatchable generators to move from one 5-minute dispatch to the next. The figure shows adequate 5-minute capability throughout the day and is comparable to the historical upward 5-

[68] Unlike wind generation, zero forecast error is assumed for solar generation both in the day-ahead and hour-ahead time frame in the production simulations. Errors due to solar forecast will exacerbate load-following shortages.

[69] The non-dispatchable generation does not include the minimum generation of gas-fired generators that are also not dispatchable.

minute capability show in Figure 4-1 of Section 4. However, the figure shows low load-following down capability during the morning hours from 4 a.m. to 10 a.m. It should be noted that Figure 5-2 shows the 5-minute capability for the day whereas the corresponding figures in Section 4 show the historical hourly maximum 5-minute load-following up and down capability. The low load-following down capability is a direct consequence of the amount of dispatchable generation that is online. During the morning hours of May 28th 2012, as shown in Figure 5-1, very few dispatchable generators are online and most are already operating at or close to their minimum load point.

As discussed in Section 3-3, insufficient capability to ramp down manifests itself as overgeneration in the production simulations. Figure 5-3 shows the overgeneration for May 28, 2012 obtained from the production simulation. This figure also shows the regulation down procurement (green line) and the CPS2 violation threshold[70] (yellow line) for the same period. While there is significant, sustained overgeneration for a few hours from 5 a.m. to 8 a.m., the rest of the time the over generation can be covered by the procured regulation or allowed to result in an ACE error if it is not sustained. Only large overgeneration sustained over 10 minutes may result in the curtailment of generation.

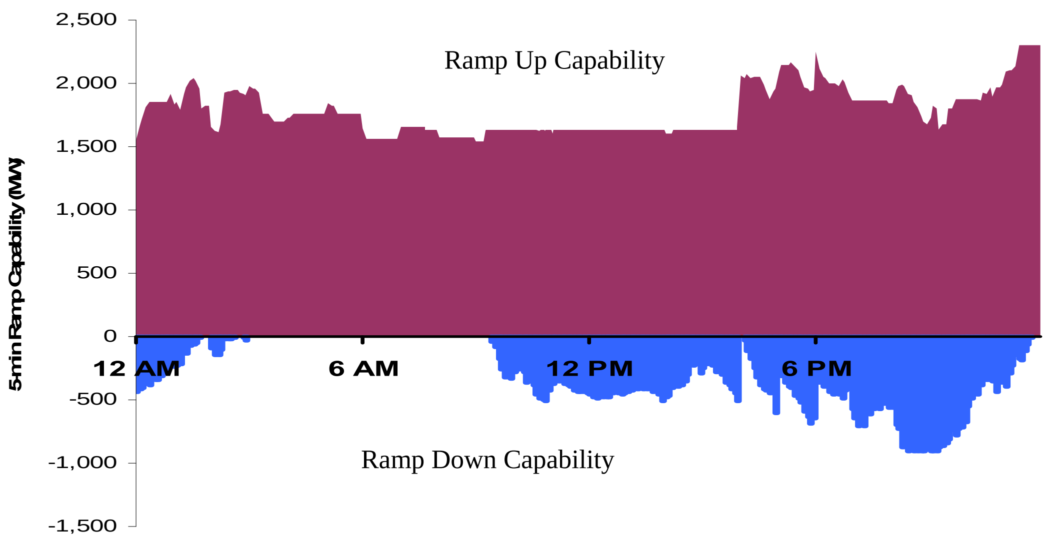


Figure 5-2: Upward and Downward 5-minute Load-Following capability for May 28th 2012

[70] CPS2 threshold is 110MW for ISO.

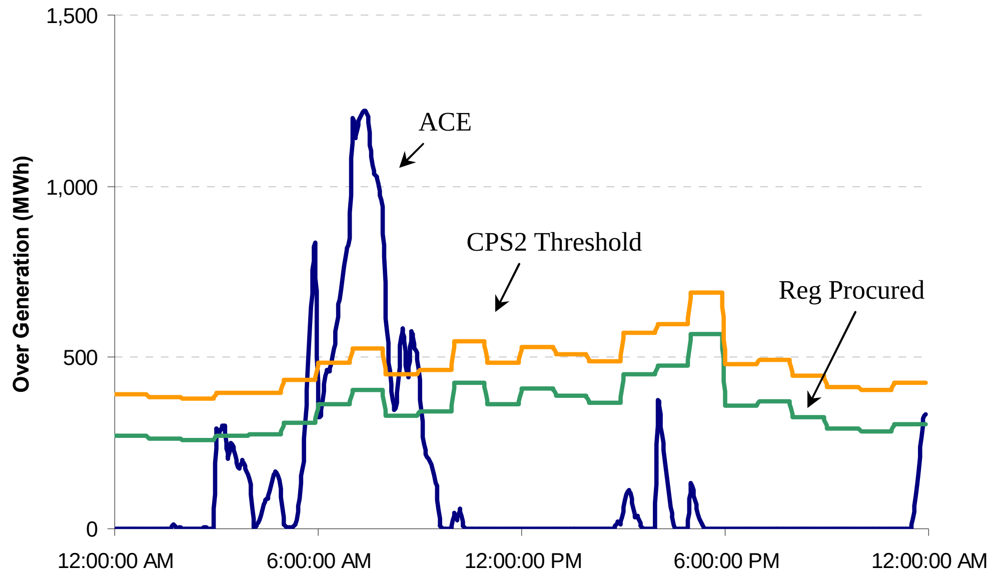


Figure 5-3: Detailed overgeneration analysis of May 28, 2012

Figure 5-4 shows the relationship between overgeneration and the amount of dispatchable generation during the hours between 4 a.m. and 10 a.m. The traces show that there is a direct correlation between overgeneration and lack of dispatchable generation. When the dispatchable generation is approaching zero, overgeneration is high. Under these conditions with very little dispatchable generation online, the fast ramp in solar generation results in an overgeneration condition. It should be noted that the solar generation ramp is not the cause of the overgeneration, rather it's the trigger. The cause for overgeneration is the lack of flexible or dispatchable resources during these hours.

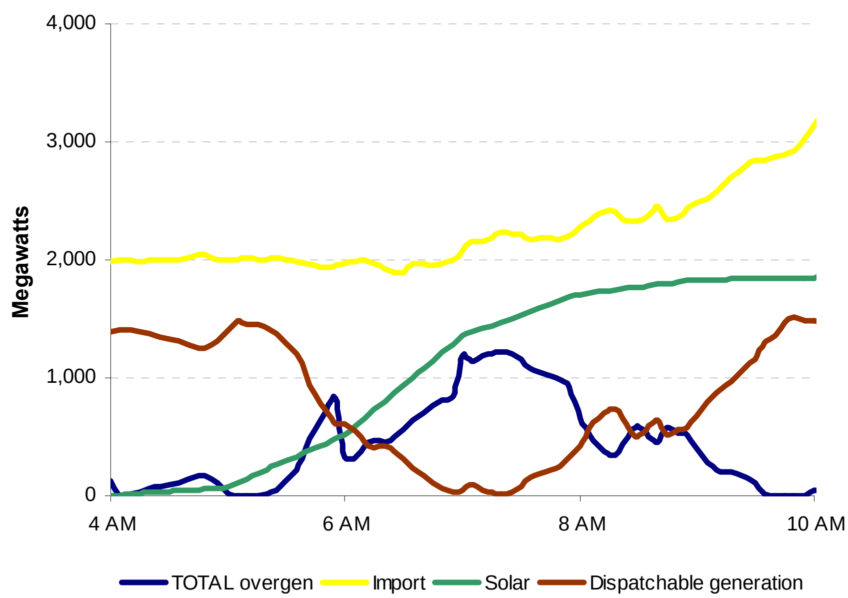


Figure 5-4: Dispatchable Generation and Overgeneration

5.2.2 Load-following Capability under High Dispatchability Conditions

Table 5.1 shows the simulated system condition for May 17, 2012. The main difference in system conditions between May 28 and May 17 is the amount of non-dispatchable resources that were online due to lower imports. Figure 5-5 shows the load (black line) and non-dispatchable generation[71] (red line) and the components of the non-dispatchable generation. The separation between the load and the non-dispatchable generation in Figure 5-5 is the amount of dispatchable generation available for load-following and regulation. More dispatchable resources are online during the morning hours, compared to May 28, 2012, as is evident from the figure.

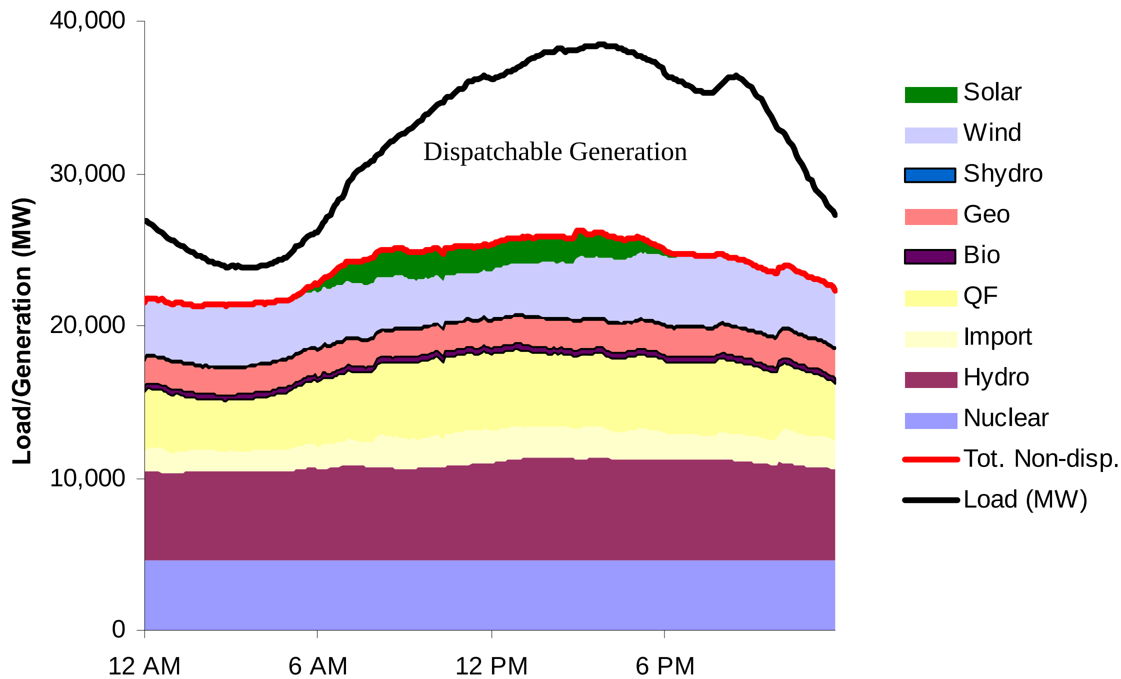


Figure 5-5: Load and Non-dispatchable Generation on May 17, 2010

Figure 5-6 shows the simulated 5-minute load-following up and down capabilities from dispatchable generators for May 17, 2012. The figure shows adequate capability throughout the day due to more dispatchable units being online.

[71] The non-dispatchable generation does not include the minimum generation of gas-fired generators that are also not dispatchable.

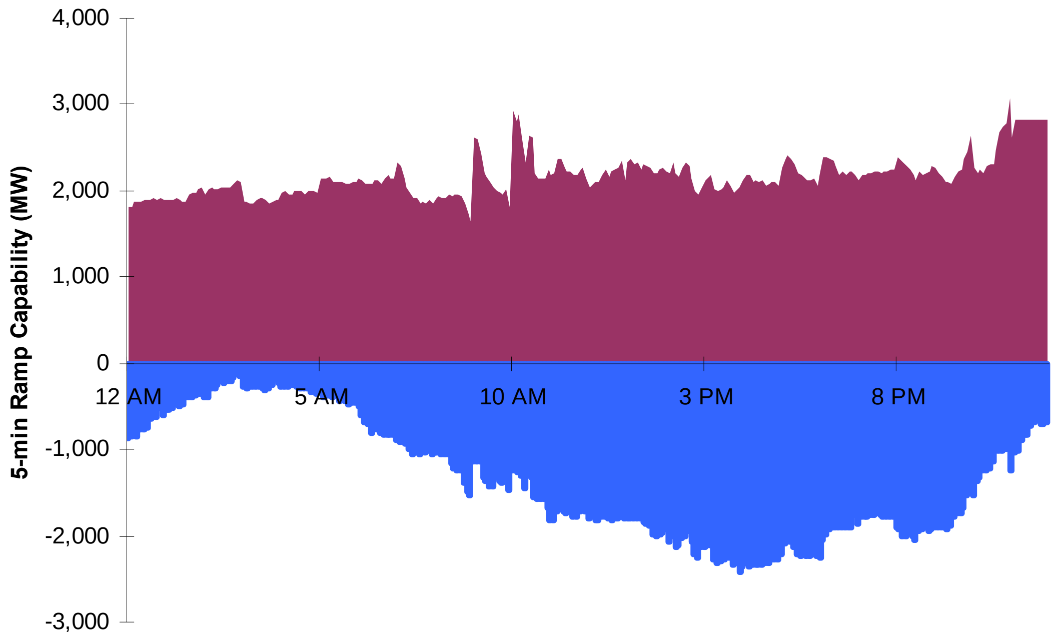


Figure 5-6: 5-minute ramp up and down capability for May 27, 2012

No overgeneration was observed in the 5-minute simulation of May 17, 2012. This reinforces the finding that load-following insufficiencies are primarily due to the lack of dispatchable generation resources. The results for the remaining days, summarized in Appendix C.7, also demonstrate that the lack of dispatchable resources causes the operational constraints. None of the detailed real-time simulations showed any significant upward load-following or regulation shortages indicating that the system has enough capability to meet load when there is a sudden decrease in variable energy resource generation.

To further analyze the impact of dispatchable gas-fired generation on overgeneration, a scatter plot of the two quantities was plotted. Figure 5-7 shows the plot of overgeneration (on the X axis) versus the amount of dispatchable gas-fired generation (on the Y axis) from a deterministic case[72] with all of the imports considered firm (100 percent firm import case). The deterministic cases that were simulated are discussed in Section 5.3. It can be observed that no overgeneration occurs when there is at least 1000 MW of dispatchable generation.

[72] In a deterministic simulation, uncertainty in load and wind generation is ignored, unlike a stochastic simulation. Since the run-time is lower, deterministic simulations were used to study the impact of various study assumptions on the results.

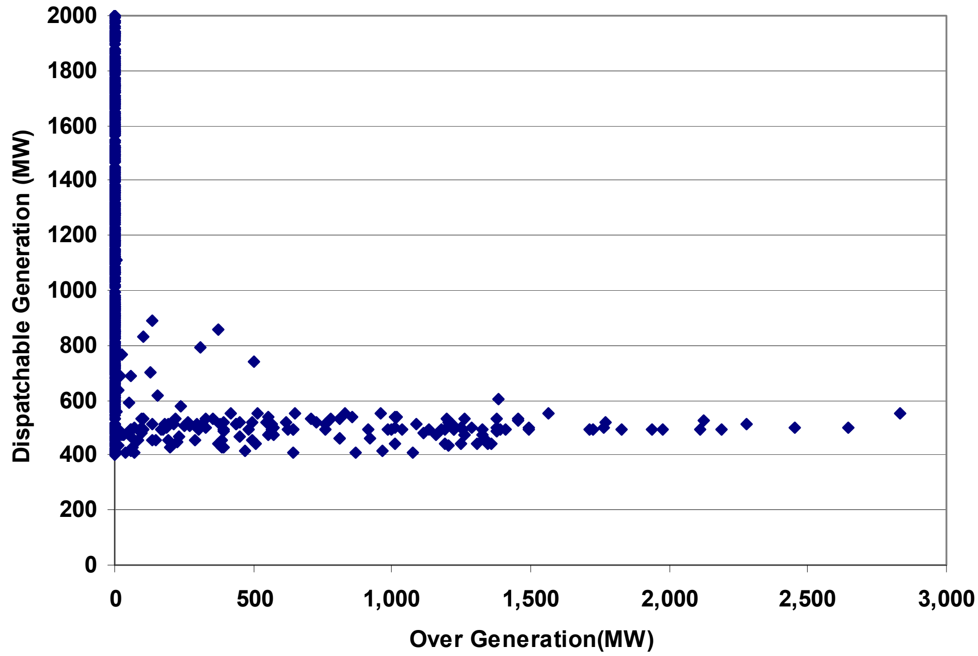


Figure 5-7: Overgeneration versus Dispatchable Generation

In contrast to the clear trend shown above, Figure 5-8 shows the overgeneration versus the system load. While no overgeneration occurs when the load is above 30,000 MW, the overgeneration occurs throughout the range of loads from 20,000 MW to 30,000 MW. These two figures again reinforce the finding that overgeneration is caused by shortages in downward dispatchable generation.

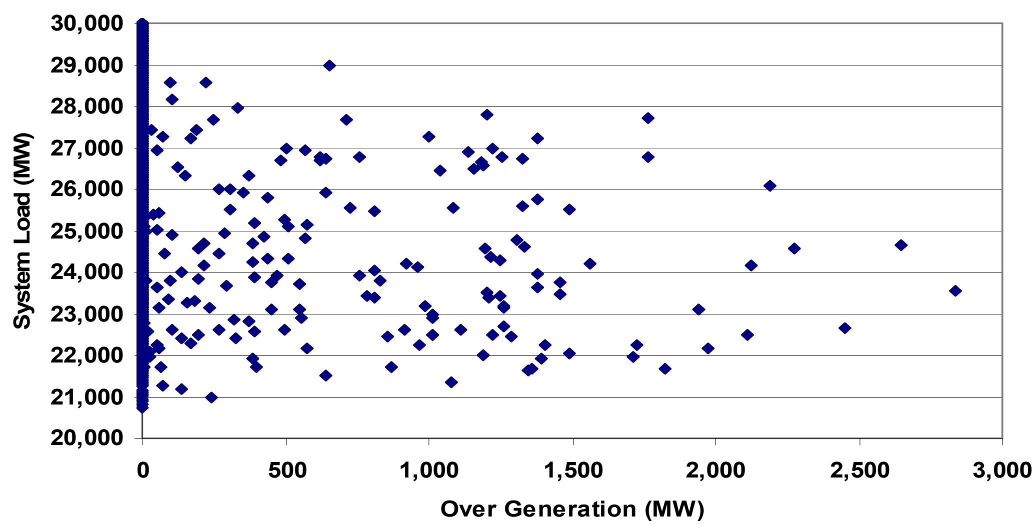


Figure 5-8: Overgeneration versus System Load

5.2.3 Quantification of Annual Load-following Shortages

The analysis shown in Section 5-2 is helpful in quantifying the shortages in load-following capability for a few selected days, and in understanding the factors that lead to the shortages. This section discusses the methodology that was used to estimate the shortage in load-following capability for the year.

Appendix C presents the results of the methodology that was used for identifying "interesting" days for stochastic, sequential simulations. The appendix discusses the approach for selecting the days for real-time simulation considering the impact of inflexibility in the existing fleet, and uncertainty and variability of load and variable energy resources on overgeneration. As shown by the hourly results in this appendix, most of the overgeneration is in the month of May, nearly 3.9 GWh. This month accounts for 80 percent of the annual overgeneration due to shortages of dispatchable generation, and uncertainty of load and generation from variable energy resources. Since this is an hourly simulation, it does not capture the impact of sub-hourly variability of load and generation from variable energy resources on the simulation.

Appendix C also quantifies the impact of intra-hour variability in load and generation from variable energy resources on overgeneration. The simulation of May 28, 2012 discussed in this appendix shows that variability increases overgeneration above and beyond what is caused by uncertainty alone. This is because variability imposes additional load-following constraints on the existing fleet, which might result in more overgeneration. Using May 28 as an example, variability doubles the overgeneration due to uncertainty of load and variable energy resources alone.

Table 5.2: Estimation of Annual Load-Following Shortages

Sensitivity Cases	GWh
(a) May overgeneration due to forecast uncertainty alone	3.90
(b) Estimated annual overgeneration due to uncertainty alone [1.20*(a)]	4.68
(c) Estimated annual overgeneration due to uncertainty and variability [2.2*(b)]	10.30

Using the information from the real-time hourly stochastic simulations, the regulation and load-following shortages for the year were estimated. Cumulative overgeneration for the high hydro case (based on 2006 loads and hydro) was roughly 10 GWh for 2012 as shown in Table 5.2. This is roughly 0.06 percent of the wind generation and 0.02 percent of the total renewable generation in 2012.

5.3 Impact of Non-dispatchability on Overgeneration

As mentioned previously, variability in wind and solar generation impacts the regulation and load-following *requirements*, while uncertainty in their generation impacts the regulation and load-following *capability* of the system. It was shown in Section 5.2 that shortages in dispatchable generation cause an inability to follow load, which in turn causes overgeneration. The preceding section quantified overgeneration due to the variability and uncertainty associated with load and variable energy resources to be 10 GWh for the year 2012. It should be pointed out that the overgeneration in this case is due to the inability of the fleet to follow net load changes in the sub-hourly time frame.

Even if the generation from wind and solar resources could be perfectly forecasted and were constant (i.e., no uncertainty and variability), the maximum generation that can be accommodated into the system will depend on the ability to dispatch the existing fleet. In this case, the overgeneration has nothing to do with the variability and uncertainty of variable energy resources. Rather, it strictly depends on whether the rest of the fleet can be dispatched down to accommodate the energy from variable energy resources.

The impact of dispatchability on overgeneration was studied both under high and low hydro conditions, under a range of assumptions regarding the dispatchable capability of generation resources and imports. This sensitivity analysis used a deterministic production simulation on an hourly basis. The intra-hourly variability and the forecast uncertainty associated with generation from variable energy resources were not modeled (but they were rather modeled as fixed, but variable by hour, production profiles). Certain portions of the generation fleet such as QFs, nuclear, biomass, hydro and imports were assumed to be non-dispatchable in this analysis. Historical hourly dispatches were assumed for these resources.

However, in reality, not all of these resources are always non-dispatchable. For example, based on an analysis of the bid data, 50 percent of the imports into California in 2006 were found to be bid into the market on an hourly basis, with the remaining being scheduled hourly as firm. The impact of increasing the dispatchable capacity on the system on the frequency and magnitude of overgeneration was studied by assuming various levels of firm imports (50 percent, 75 percent and 100 percent). Since overgeneration is more likely to occur at low loads, the impact of zero load growth from 2006 to 2012, but with the expected renewable generation additions, was also studied. A deterministic production simulation on an hourly time-step was conducted for all these cases. The assumptions for the deterministic cases are shown in Table 5.3.

Table 5.3: Assumptions for the Deterministic Production Simulations

Case	Load	Imports
50 % Import Case	2006 Load ×(1+0.015)^6	50% Fixed*, 50% Dispatchable
75 % Import Case	2006 Load ×(1+0.015)^6	100% Fixed
100 % Import Case	2006 Load ×(1+0.015)^6	50% Fixed*, 50% Dispatchable
No Load Growth Case	2006 Load	50% Fixed*, 50% Dispatchable

* Based on 2006 imports

Under the assumptions listed above, in the base case simulation, with 50 percent firm imports, no overgeneration was observed as a result of shortages in dispatchable generation. The most severe overgeneration was from the zero load growth case, as shown in Figure 5-9. Overgeneration in this case was roughly 150 GWh for the year, which is 0.84 percent of the expected wind energy and 0.32 percent of the total renewable generation in 2012. Most of the overgeneration occurs in late spring (April-May), due to combination of high generation from hydro and variable energy resources, and low loads. The 75 percent and 100 percent import cases also showed some overgeneration as shown in Figure 5-9. In general, there appears to be sufficient flexible generation available to operate, if the ISO is not blocked from doing so due to an excess of non-dispatchable generation, including imports.

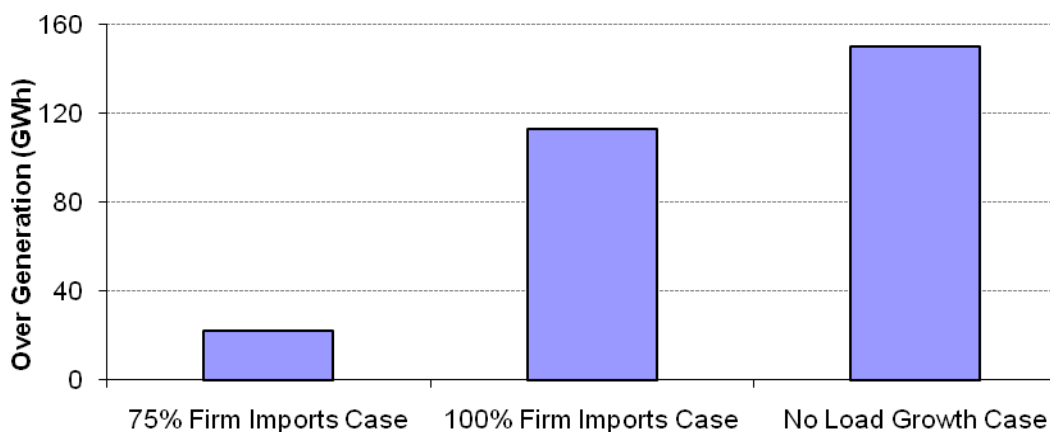


Figure 5-9: Volume of Annual Overgeneration (GWh) in Three Sensitivity Cases

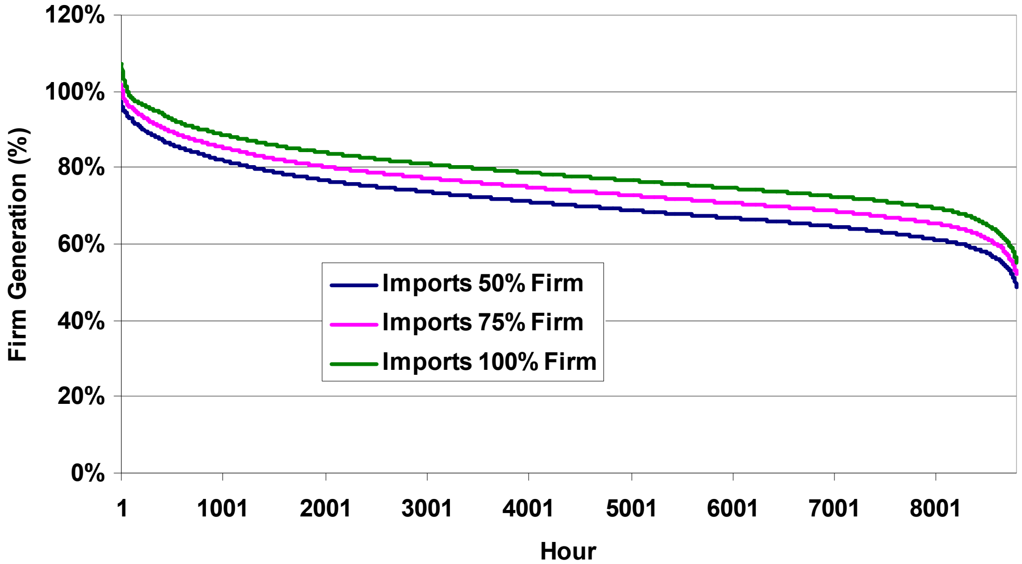


Figure 5-10: Duration curves for non-dispatchable generation with different levels of firm imports

Figure 5-10 shows the non-dispatchable generation in the three cases (50 percent, 75 percent and 100 percent import) as a percentage of the load. It can be observed that at higher percentages of firm imports, the total non-dispatchable generation is higher than load during a few hours, which results in overgeneration.

5.4 Fleet Operations and Economic Impacts

The production simulations results were also used to provide an initial evaluation of the impacts of 20 percent renewable energy production on the operations and revenues of the dispatchable thermal generation fleet. Table 5.4 shows the impact on the combined cycle fleet. This table shows the number of starts, on-peak and off-peak energy, CO2 emissions and revenues for the 20 percent RPS case, as well as the 2012 Reference case.[73] Tables 5.5 and 5.6 show the impacts on the simple cycle gas turbine and gas-fired steam turbine fleet, respectively. The 20 percent renewable energy modeled results in the combined cycle units starting and stopping more frequently. With the additional renewable production, combined cycle generator starts increase by 35 percent. Also, the energy from the combined cycle units reduces by roughly 9 percent, with more reduction occurring during off-peak hours, indicating increased cycling. The table also shows a reduction in CO_2 emissions from combined cycle generators due to the reduction in operations, although this was calculated using a single emissions factor multiplied by energy output, and did not consider the potential for higher emissions at less efficient levels of operations.

[73] The 2012 Reference case uses the same load and other assumptions as the 20 percent RPS case, except that the renewable portfolio includes only the renewable resources online in 2006.

Table 5.4: Aggregate Operational, Emissions and Revenue Changes for Combined Cycle Units

	20% RPS case	2012 Reference case	Percent change
Number of starts	3,362	2,492	35 %
On-peak Energy (MWh)	32,421,142	36,258,580	-11 %
Off-peak Energy (MWh)	26,146,347	31,055,863	-16 %
CO2 Emissions (tons)	24,266,005	27,969,588	-13 %
Revenue ($,000)	3,455,290	4,103,959	-16 %

Table 5.5: Aggregate Operational, Emissions and Revenue Changes for Simple Cycle Gas Turbines

	20% RPS case	2012 Reference case	Percent change
Number of starts	9,618	12,123	-21 %
On-peak Energy (MWh)	6,223,446	10,244,121	-39 %
Off-peak Energy (MWh)	3,359,432	5,034,037	-33 %
CO2 Emissions (tons)	5,591,607	8,660,370	-35 %
Revenue ($,000)	605,167	996,017	-39 %

Table 5.6: Aggregate Operational, Emissions and Revenue Changes for Gas-fired Steam Turbines

	20% RPS case	2012 Reference case	Percent change
Number of starts	2,653	3,392	-22 %
On-peak Energy (MWh)	5,109,377	7,179,751	-29 %
Off-peak Energy (MWh)	3,396,360	4,125,934	-18 %
CO2 Emissions (tons)	3,654,106	4,598,358	-21 %
Revenue ($,000)	522,329	735,255	-29 %

While the number of starts for combined cycle units increase with 20 percent renewable energy, the simulations show that the number of starts, along with energy produced, decrease quite substantially for simple cycle gas turbines and gas-fired steam turbines.

Figures 5-11 and 5-12 show the generation from combined cycle, simple cycle and gas-fired steam turbines for the same week in January, 2012, for the two cases. The combined cycle energy (area shown in blue) is smaller for the 20 percent RPS compared to the 2012 reference case. Also, the valleys in combined cycle generation are deeper indicating that more of these units either turn down and shutdown during off-peak hours.

Two conflicting impacts are at work here. On the one hand, the renewables decrease the overall amount of gas-fired generation required. The overall level of gas generation drops several thousand MW across the week, thereby decreasing the total energy and the number of starts. The average displacement by season and hour due to the renewable profiles being modeled can be seen in the gap between the load and net load in Figures 2-1 to 2-4. On the other hand, the uncertainty and variability tends to push up the number of starts. These simulation results likely underestimate production because intra-hourly load-following is not modeled.

Figures 5-13 and 5-14 show the seasonal on-peak and off-peak energy from combined cycle, simple cycle GT, gas-fired steam, wind and solar resources for the 20% RPS case and the 2012 reference case. From these two figures, it is clear that during on-peak hours, the incremental wind and solar generation displace the generation primarily from simple cycle and gas-fired steam generators. During off-peak hours, the generation from the incremental wind and solar generation has a bigger impact on the generation from combined cycle units.

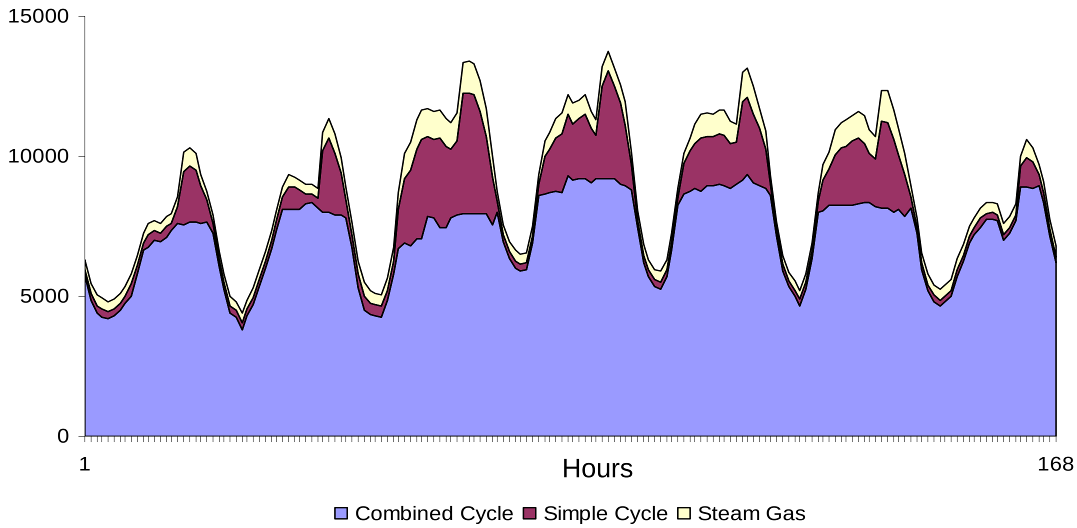


Figure 5-11: Weekly generation for gas units in the 2012 reference case

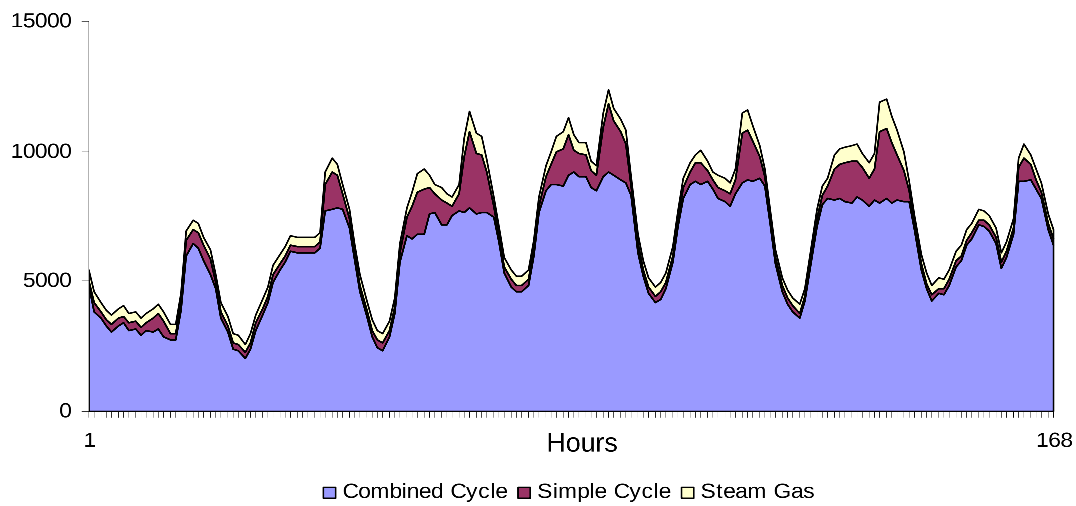


Figure 5-12: Weekly generation for gas units in the 20 percent RPS case

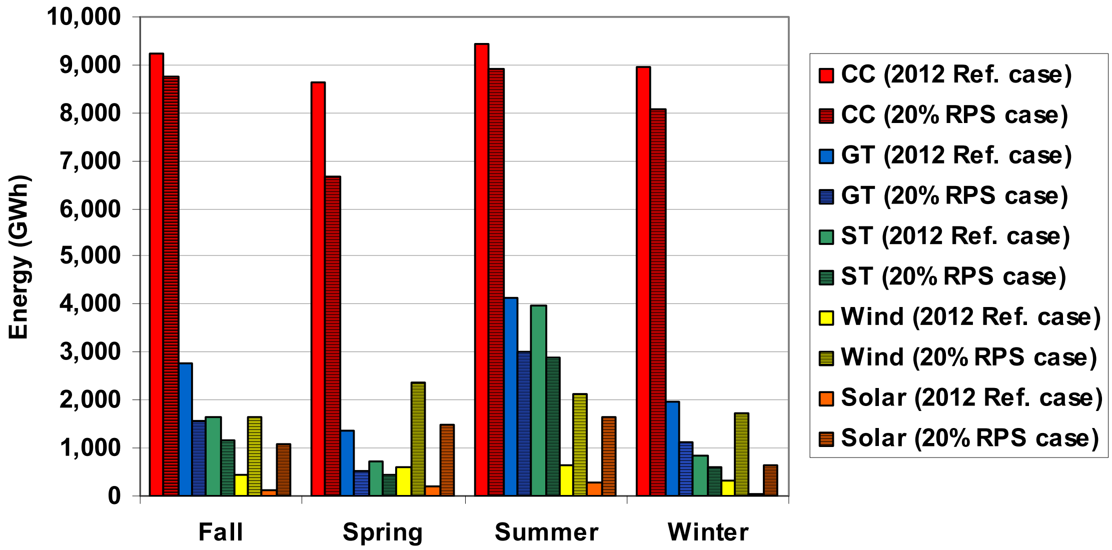


Figure 5-13: Seasonal on-peak energy by thermal and renewable technologies for (a) 2012 reference case (b) 20 percent RPS case

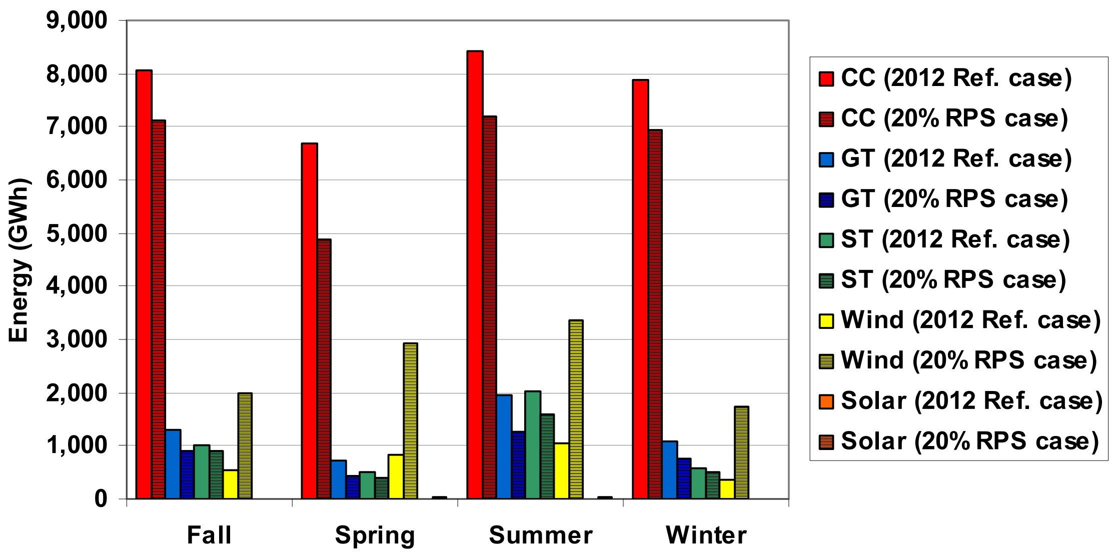


Figure 5-14: Seasonal off-peak energy by thermal and renewable technologies for (a) 2012 reference case (b) 20 percent RPS case

The energy market revenues for the combined cycle, simple cycle gas turbine and steam units are lower in the 20 percent RPS case, compared to the 2012 reference case, by 16 percent, 39 percent and 29 percent respectively. The revenues for combined cycle, simple cycle gas turbine and steam units are lower due to the compounding effect of lower dispatch and lower energy prices. Figure 5-15 and 5-16 show the energy prices in the summer and spring for the two cases. The figure shows the minimum, maximum and standard deviation of the seasonal average hourly spot prices. On an average, the energy prices in the 20 percent RPS case are lower by $2.50 /MWh compared to the 2012 reference case. The lower energy prices, combined with the lower capacity factor, have a negative impact on the revenues of thermal units. Peaking units such as simple cycle gas turbines and steam turbines are impacted more in the 20 percent RPS case because they operate less during the peak hours of the days when energy prices are higher.

Also, it can be observed that the price volatility is higher in the 20 percent RPS case. The spring plot shows few hours when the price is zero or negative due to overgeneration. These periods correspond to solar and wind ramp up periods discussed in other sections of the report. The price volatility in the negative direction also has an impact on generator revenues.

These simulated revenue results, based on marginal production costs, are provided to illustrate potential changes in energy market revenues rather than as a forecast; actual market prices will reflect factors not considered, or only partially considered, in the model, such as congestion and the effect on prices of market bids. Also, revenues from ancillary services are not included in the annual revenues. Further analysis to quantify operational and economic impacts on fleet is required, especially at higher levels of RPS.

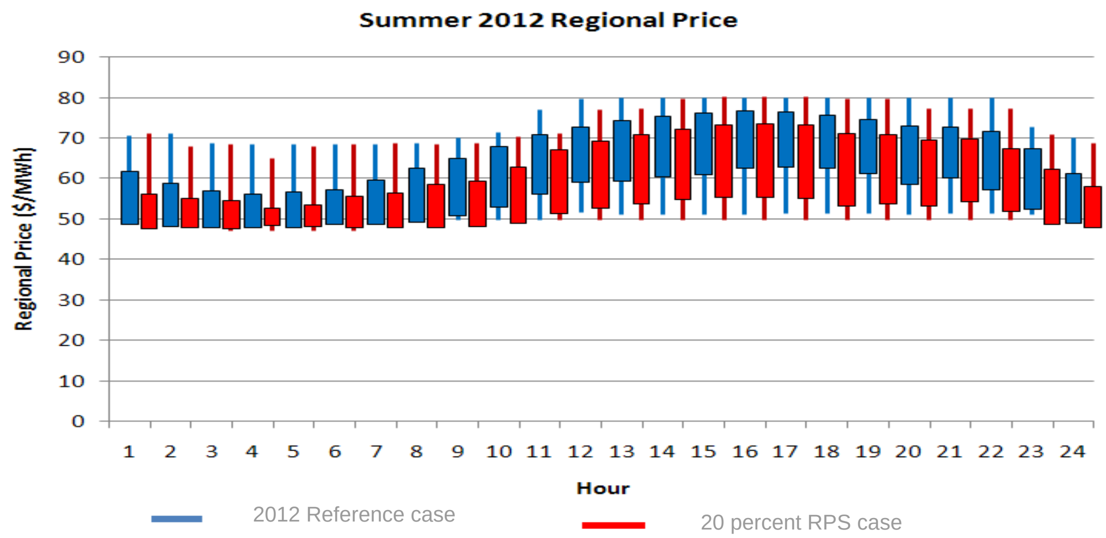


Figure 5-15: Summer 2012 Prices for the cases (a) 2012 reference case (b) 20 percent RPS case

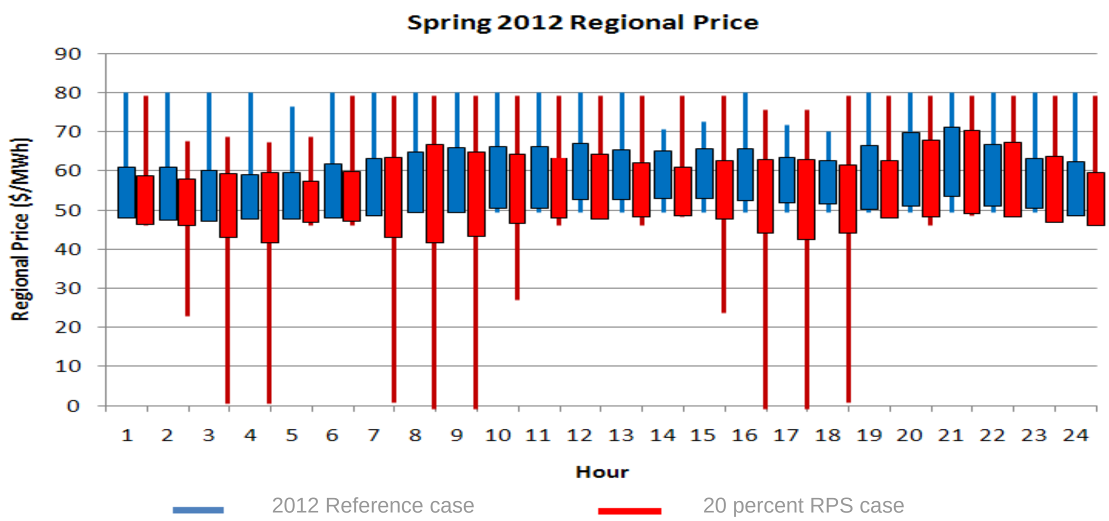


Figure 5-16: Spring 2012 Prices for the cases (a) 2012 reference case (b) 20 percent RPS case

6 Key Study Conclusions and Recommendations

The study shows that the generation fleet is capable of meeting the regulation up and down requirements, as well as the load-following ramp up requirements under the 20 percent RPS. Sufficient upward ramp capability was found both in the empirical analysis of the dispatch over the past 15 months (although there may be few intervals in the analysis where upwards capability is tight) and the production simulations.

The production simulation analysis showed that under certain conditions (for example, low load, high hydro and wind generation in May), the system may not have adequate flexible generation to meet the load-following down ramp requirement. In the methodology that was employed, the shortages in the ramp down capability are captured as overgeneration. The cumulative overgeneration for the high hydro case (based on 2006 loads and hydro) was roughly 10 GWh for 2012. This is roughly 0.02 percent of the expected renewable generation in 2012 and fairly insignificant. However, in the production simulations, the entire gas fleet was assumed to be dispatchable. The ramp down shortages can be exacerbated due to self-scheduling. Hence, the simulation result may be an under-estimate of actual overgeneration at 20 percent RPS.

Currently, a large portion of the generation fleet is self-scheduled and therefore not responding to 5-minute economic dispatch commands from the ISO. As a result, some periods may have insufficient dispatchable generation to follow load and variable energy production. The fleet capability analysis shows that due to self-schedules, the downward 5 minute capability of the generation fleet can be depleted. However, if no resource self-schedules, there is sufficient downward ramp capability inherent in the dispatch. This finding points to the significant negative impact that self-scheduling could have on efficient commitment and dispatch in high renewables scenarios. In fact, the ISO is already experiencing many hours of negative prices during off-peak hours in spring and summer, which is an indication that self-schedules are being violated to ensure reliable operations.

The study results indicate that the ISO should pursue incentives or mechanisms to reduce the level of self-scheduled resources during certain periods. The reduction in self-schedules will give the system the needed down ramp capability under certain conditions. The same outcome can also be achieved by reducing the amount of other non-dispatchable generation that are in the form of imports, hydro, QFs, geothermal etc. during these periods. There appears to be sufficient flexible generation available to operate with a 20 percent RPS if the ISO is not blocked from doing so due to an excess of non-dispatchable generation (including imports).The ISO is undertaking a large number of initiatives in system operations (notably improved wind and solar forecasting and visualization capabilities), grid planning and market design to prepare for renewable integration. These initiatives will not be reviewed here, but rather a few key recommendations that reflect the study findings are summarized.

- **Evaluate market and operational mechanisms to improve utilization of existing generation fleet operational flexibility**. As noted, the study confirmed that the generation fleet possesses sufficient overall operational flexibility to reliably integrate 20 percent RPS in over 99 percent of the hours studied. However, the current markets restrict ISO's access to that full capability due to self-scheduling. The empirical analysis provided information on the difference between load-following capabilities in the downward direction when resources are self-scheduled compared to their actual physical capabilities. Hence, the study makes clear that the ISO should pursue incentives or mechanisms to reduce the level of self-scheduled resources and/or increase the operating flexibility of otherwise dispatchable resources.

- **Evaluate means to obtain additional operational flexibility from wind and solar resources.** The simulations demonstrated the need for additional dispatchable capacity in the morning hours under certain conditions. The ISO should explore market rules and incentives intended to encourage greater participation by wind and solar resources in the economic dispatch or ancillary services. Greater economic dispatch control, including curtailment and ramp rate limitations, can be used in targeted circumstances to mitigate overgeneration or shortfall in regulation and load-following capability generally.

- **Improve day-ahead and real-time forecasting of operational needs: *(a) develop a regulation prediction tool.*** The analysis demonstrated that regulation needs will vary substantially from hour to hour depending on the expected production from wind and solar resources. The development of a means to forecast the next day's hourly regulation needs based on probabilities of expected renewable resource output would enhance the efficiency of regulation procurement in the day-ahead time frame.

- **Improve day-ahead and real-time forecasting of operational needs: *(b) develop a ramp/load-following requirement prediction tool.*** The study identified the potential for significant increases in load following capacity and ramp requirements at 20 percent RPS. While forecasts can identify the need in the day-ahead and hour-ahead time frame, they cannot currently identify the presence of ramp constraints that may limit the ability of generation to meet those requirements. The ISO should evaluate the development of improved forecasting of ramp requirements and whether to modify day-ahead and real-time unit commitment algorithms and processes to reflect those ramp requirements.

- **Further analysis to quantify operational and economic impacts on fleet at higher levels of RPS.** Although this study was not focused on the impact of renewable integration on the revenues of existing generation, it has provided some indications of possible changes in such revenues, primarily through changes in energy market prices. Further analysis is needed to clarify the net revenue impact over time from changes in energy and ancillary services procurement, as well as consideration of the implications for capacity payments.

APPENDIX A-1: Comparison of seasonal results for the operational requirements simulations

This appendix presents supplemental figures and tables for Section 3, showing all seasons. Definitions of the operational requirements shown in the figures and tables are the same as in Sections 2 and 3, as is discussion of the methodology used for the simulations

The figures and graphs in this appendix follow the conventions noted in Sections 2 and 3 of the report. In the figures, the hourly results are represented as typical "stock" or "whisker" charts. The two ends of the line represents the range (minimum, maximum) of the results and the bar shows the average ± one standard deviation. Red bars and lines refer to the 2012 simulations; Blue bars and lines refer to the 2006 simulations.

In all instances, references to the operational requirements in 2006 refer to the *simulated* operational requirements for the base year. Also, the results reported in the following tables and figures as *maximums* are the 95th percentile occurrence for a particular hour.[1]

[1] That is, excluding the 5% highest results from the simulations.

Figure A-1: Regulation Up Capacity Requirements by Hour of Day, All Seasons

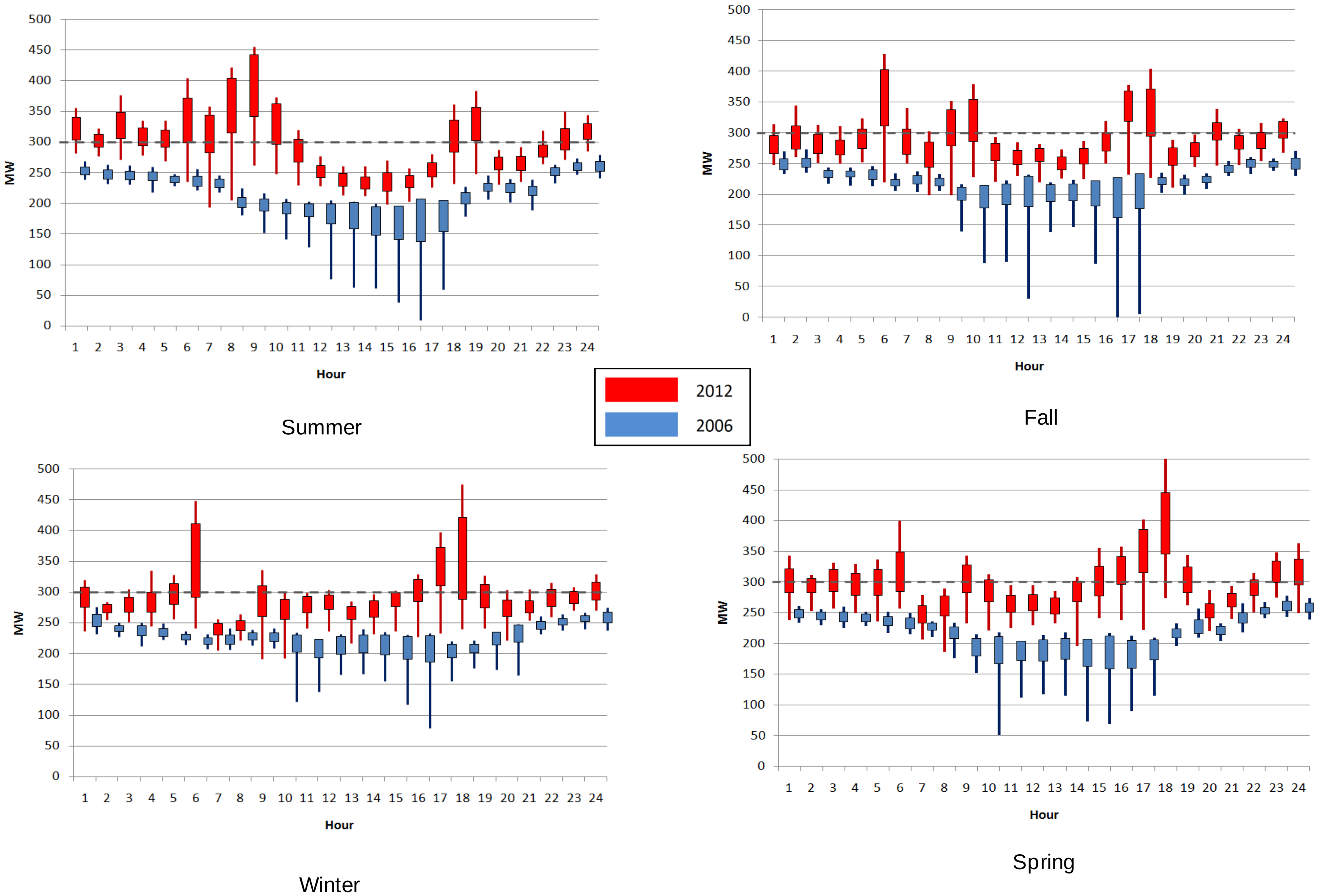


Figure A-2: Regulation Down Capacity Requirements by Hour of Day, All Seasons

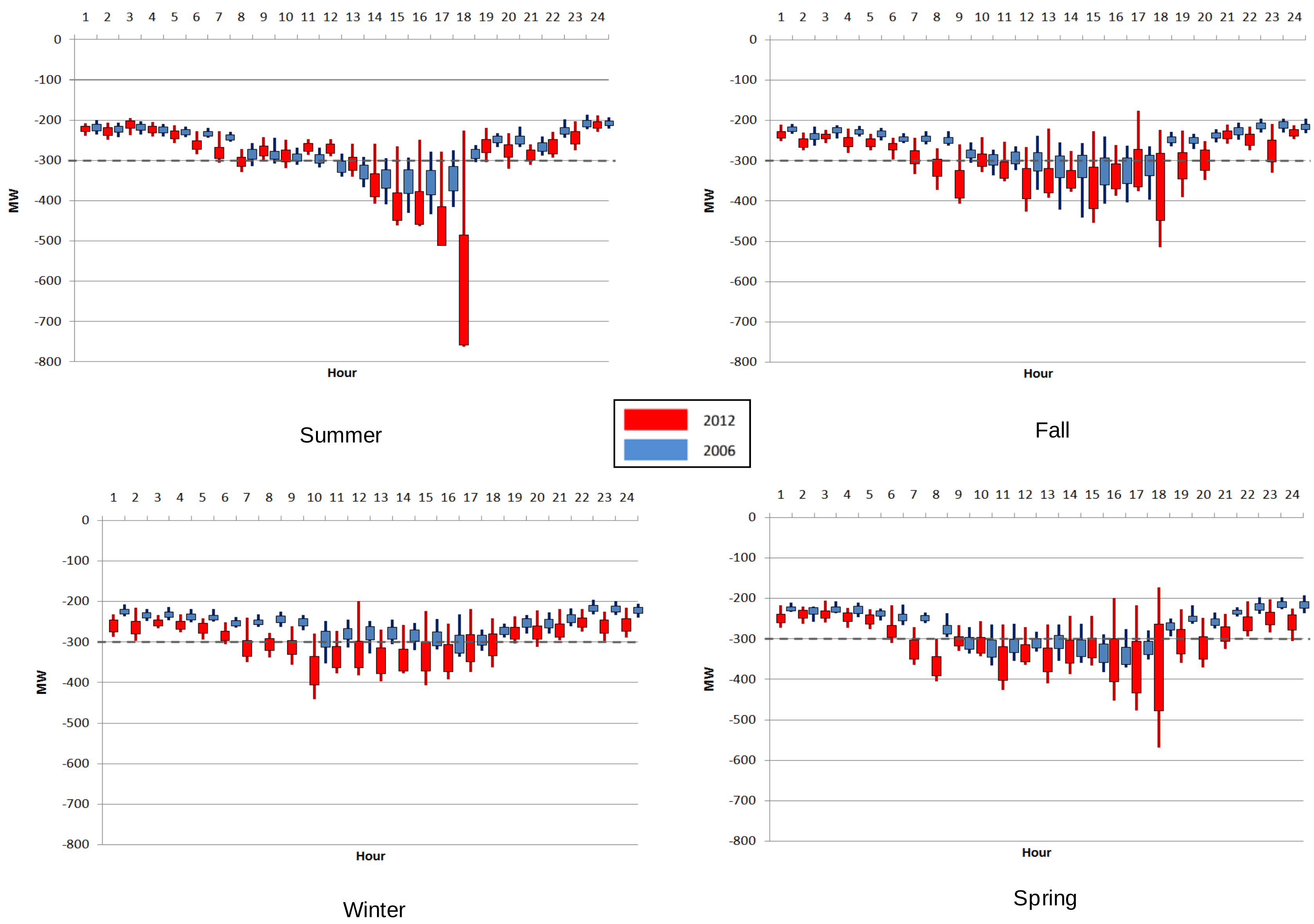


Figure A-3: Load Following Up Capacity Requirements by Hour of Day, All Seasons

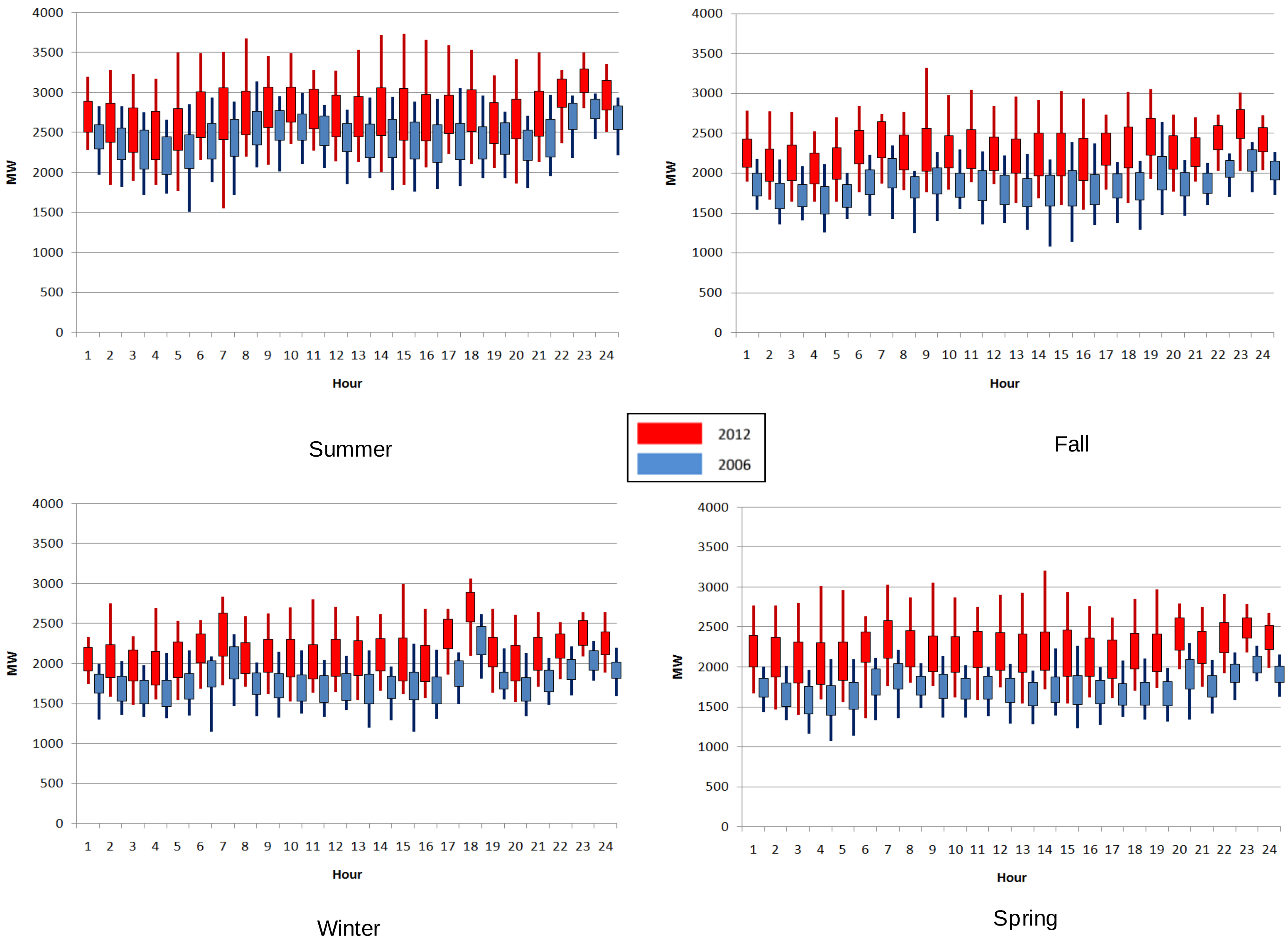


Figure A-4: Load Following Down Hourly Capacity Requirements by Hour of Day, All Seasons

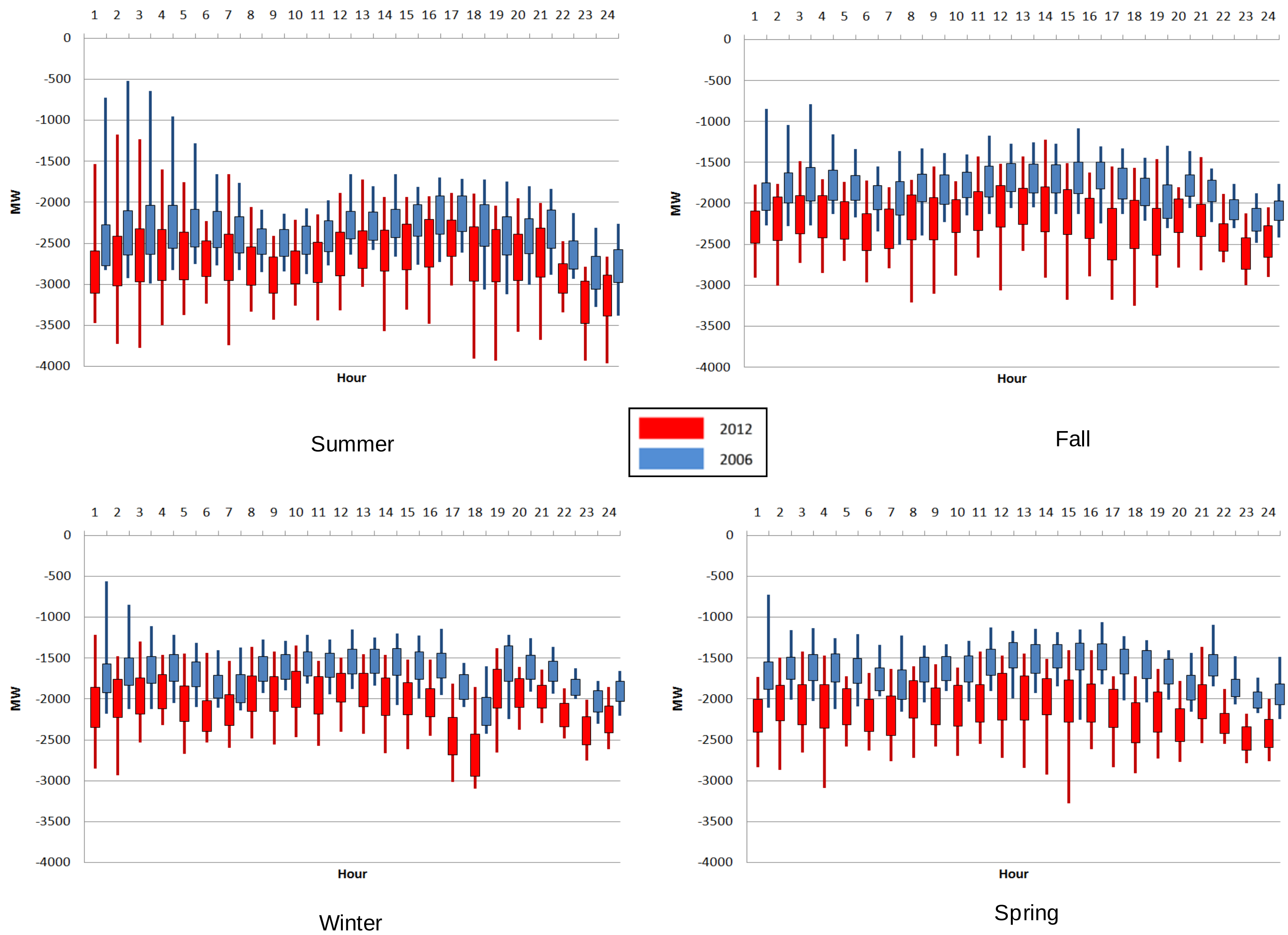


Figure A-5: Regulation Up Capacity, Frequency Distribution of Hourly Maximum Values across the Season, All Seasons

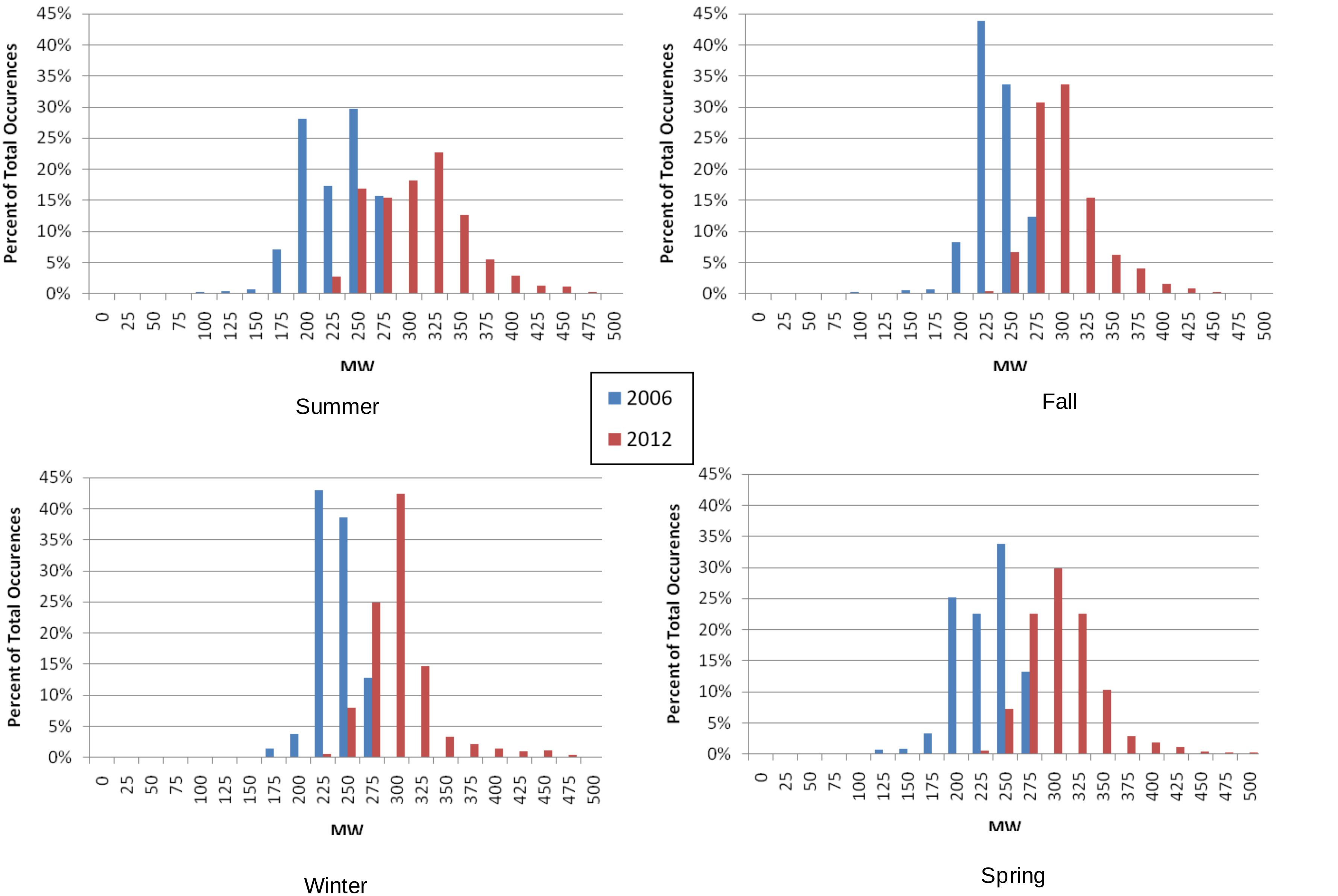


Figure A-6: Regulation Down Capacity, Frequency Distribution of Hourly Maximum Values across the Season, All Seasons

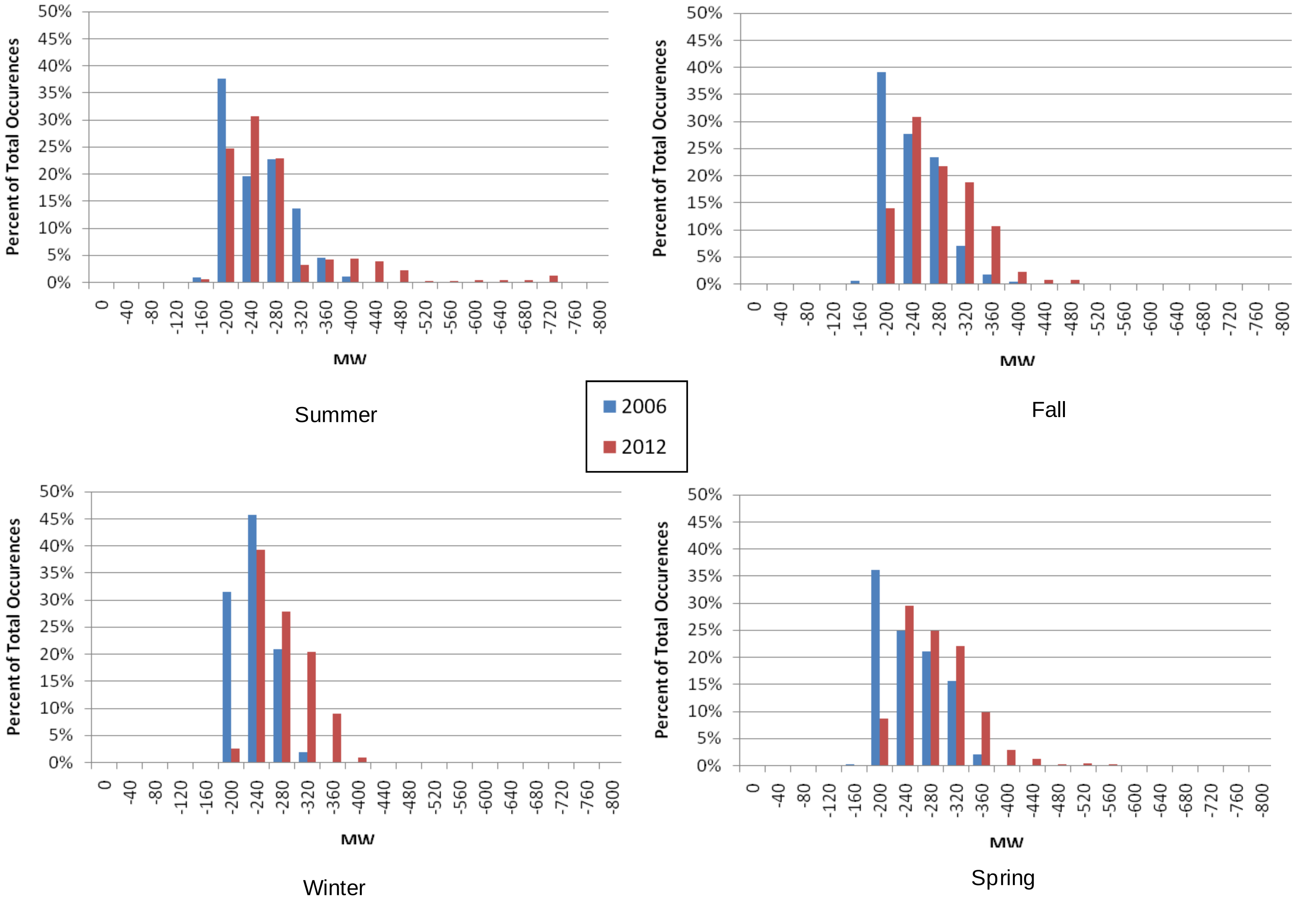


Figure A-7: Load Following Up Capacity, Frequency Distribution of Hourly Maximum Values across the Season, All Seasons

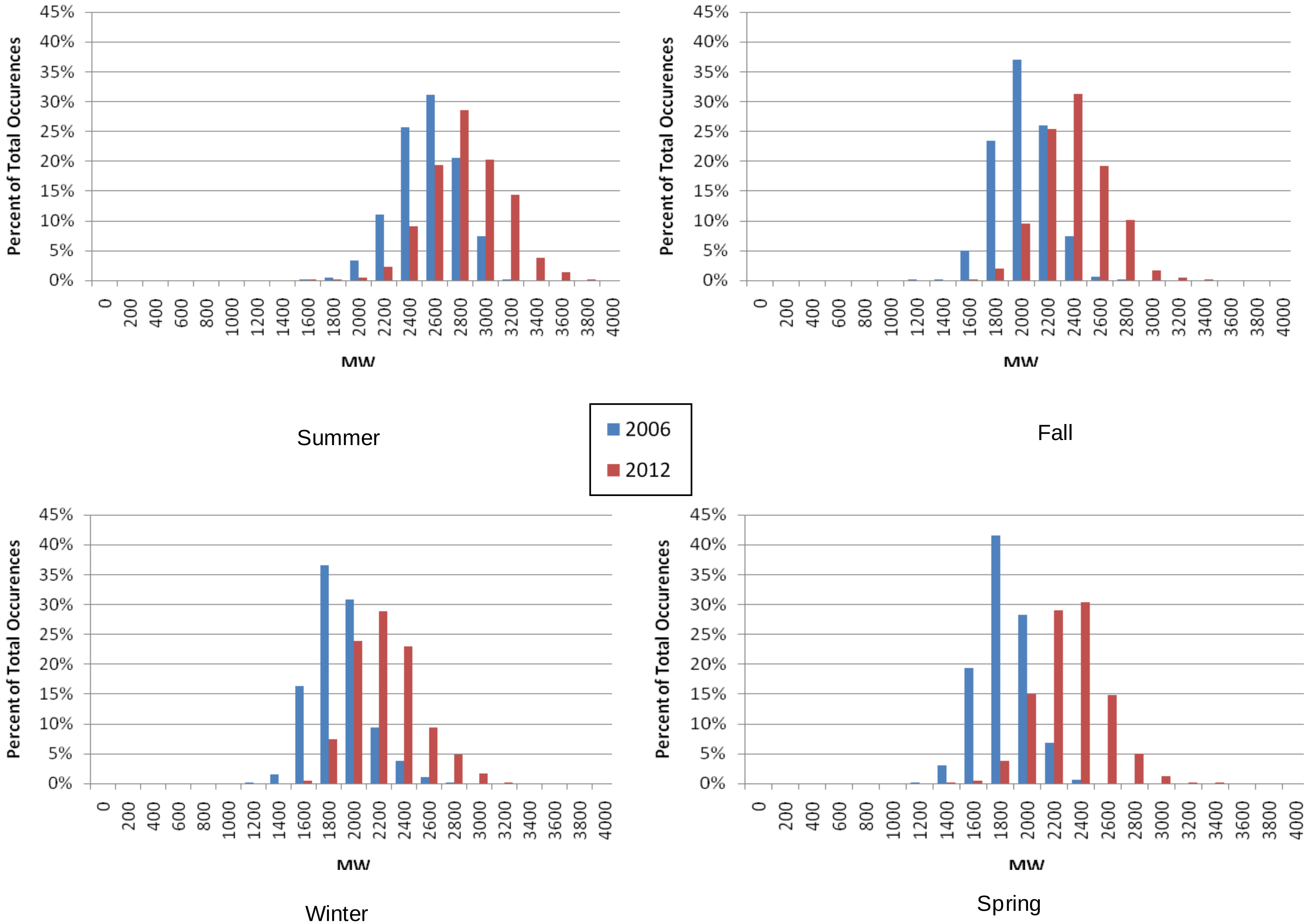


Figure A-8: Load Following Down Capacity, Frequency Distribution of Hourly Maximum Values across the Season, All Seasons

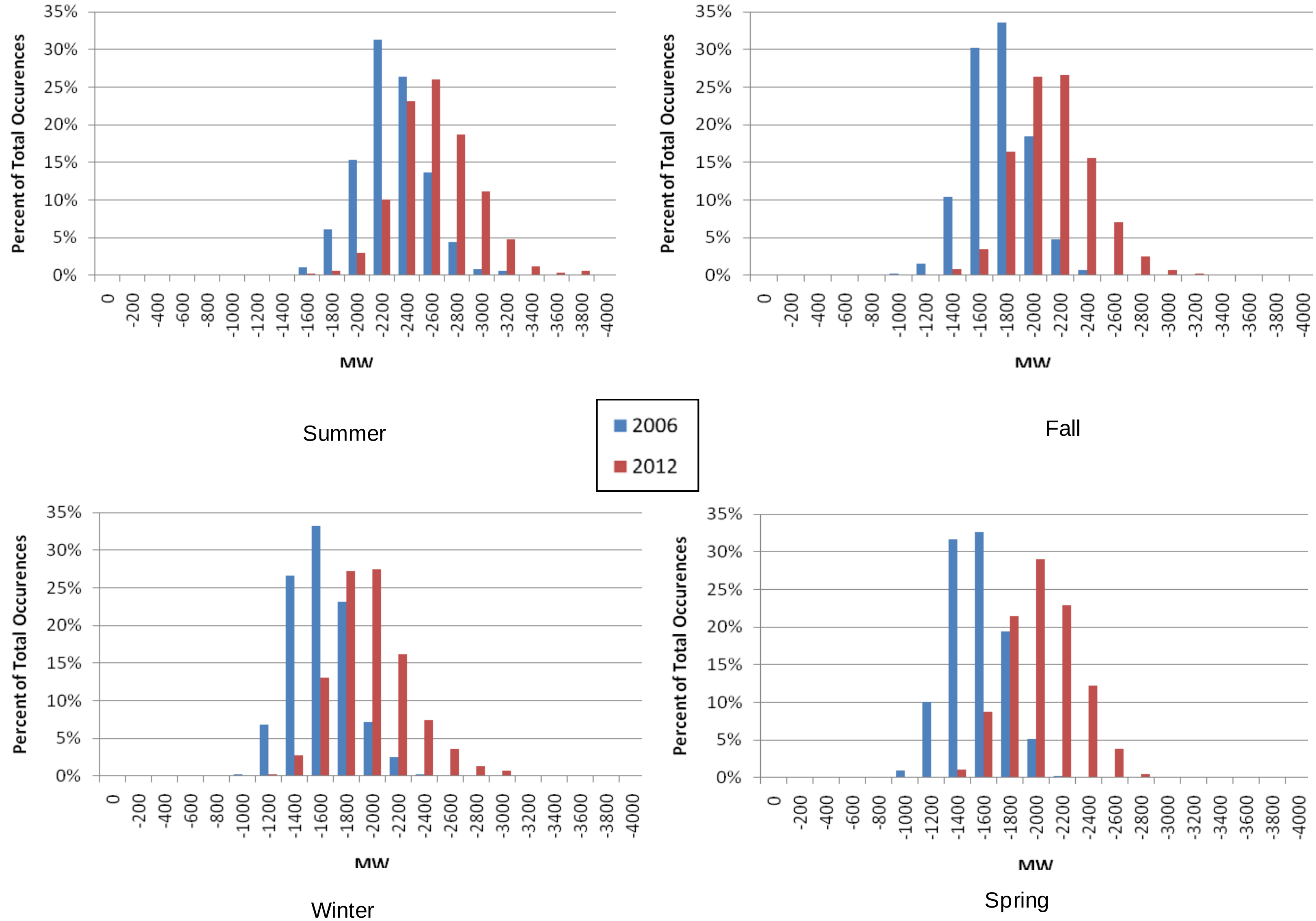


Table A-1: Spring Hourly Results, full portfolio (load, wind and solar), all forecast errors, hours 1-12

	1	2	3	4	5	6	7	8	9	10	11	12
Maximum load-following up capacity (MW) – 2012	2,767	2,773	2,801	3,012	2,968	2,639	3,030	2,871	3,055	2,873	2,755	2,901
Maximum load-following up capacity (MW) – 2006	1,999	2,008	1,963	2,091	2,093	2,109	2,207	2,046	2,132	2,013	1,991	2,036
Maximum load-following down capacity (MW) – 2012	(2,836)	(2,868)	(2,654)	(3,088)	(2,580)	(2,630)	(2,765)	(2,723)	(2,581)	(2,698)	(2,548)	(2,722)
Maximum load-following down capacity (MW) – 2006	(2,100)	(1,999)	(2,019)	(2,117)	(2,082)	(1,958)	(2,145)	(2,038)	(1,893)	(2,029)	(1,895)	(1,988)
Maximum Regulation Up capacity (MW) – 2012	343	311	331	329	336	399	279	289	342	312	294	294
Maximum Regulation Up capacity (MW) – 2006	260	255	259	251	251	249	234	233	214	217	202	213
Maximum Regulation Down capacity (MW) – 2012	(273)	(263)	(259)	(273)	(277)	(311)	(364)	(406)	(330)	(343)	(426)	(365)
Maximum Regulation Down capacity (MW) – 2006	(233)	(258)	(236)	(245)	(255)	(265)	(261)	(295)	(336)	(366)	(354)	(331)

Table A-2: Spring Hourly Results, full portfolio (load, wind and solar), all forecast errors, hours 13-24

	13	14	15	16	17	18	19	20	21	22	23	24
Maximum load-following up capacity (MW) – 2012	2,928	3,207	2,942	2,762	2,621	2,857	2,976	2,794	2,752	2,918	2,788	2,678
Maximum load-following up capacity (MW) – 2006	1,953	2,228	2,259	1,991	2,079	2,102	1,987	2,292	2,088	2,175	2,260	2,148
Maximum load-following down capacity (MW) – 2012	(2,845)	(2,926)	(3,275)	(2,614)	(2,838)	(2,910)	(2,731)	(2,771)	(2,542)	(2,548)	(2,782)	(2,761)
Maximum load-following down capacity (MW) – 2006	(1,922)	(1,840)	(2,246)	(1,816)	(2,012)	(2,030)	(2,004)	(2,148)	(1,834)	(2,061)	(2,166)	(2,239)
Maximum Regulation Up capacity (MW) – 2012	286	309	356	358	402	502	344	287	293	315	348	363
Maximum Regulation Up capacity (MW) – 2006	217	205	215	212	209	232	255	232	264	266	277	272
Maximum Regulation Down capacity (MW) – 2012	(410)	(387)	(366)	(452)	(476)	(569)	(359)	(371)	(325)	(294)	(284)	(305)
Maximum Regulation Down capacity (MW) – 2006	(353)	(359)	(382)	(371)	(350)	(293)	(263)	(273)	(245)	(237)	(226)	(236)

Table A-3: Summer Hourly Results, full portfolio (load, wind and solar), all forecast errors, hours 1-12

	1	2	3	4	5	6	7	8	9	10	11	12
Maximum load-following up capacity (MW) – 2012	3,198	3,285	3,234	3,174	3,500	3,496	3,507	3,675	3,461	3,491	3,281	3,278
Maximum load-following up capacity (MW) – 2006	2,826	2,823	2,752	2,663	2,854	2,933	2,888	3,140	2,948	2,993	2,845	2,782
Maximum load-following down capacity (MW) – 2012	(3,473)	(3,727)	(3,774)	(3,496)	(3,372)	(3,238)	(3,745)	(3,333)	(3,432)	(3,258)	(3,438)	(3,316)
Maximum load-following down capacity (MW) – 2006	(2,810)	(2,911)	(2,972)	(2,809)	(2,743)	(2,752)	(2,814)	(2,838)	(2,830)	(2,862)	(2,754)	(2,624)
Maximum Regulation Up capacity (MW) – 2012	355	321	376	334	334	404	357	421	455	373	319	276
Maximum Regulation Up capacity (MW) – 2006	268	263	261	259	248	256	245	224	216	207	202	204
Maximum Regulation Down capacity (MW) – 2012	(238)	(249)	(237)	(241)	(257)	(285)	(306)	(329)	(304)	(320)	(286)	(291)
Maximum Regulation Down capacity (MW) – 2006	(236)	(243)	(236)	(241)	(242)	(245)	(254)	(315)	(308)	(312)	(318)	(340)

Table A-4: Summer Hourly Results, full portfolio (load, wind and solar), all forecast errors, hours 13-24

	13	14	15	16	17	18	19	20	21	22	23	24
Maximum load-following up capacity (MW) – 2012	3,538	3,718	3,737	3,661	3,592	3,535	3,213	3,415	3,502	3,286	3,505	3,362
Maximum load-following up capacity (MW) – 2006	2,933	2,944	2,883	2,916	3,053	2,964	2,757	2,712	2,969	2,960	2,986	2,937
Maximum load-following down capacity (MW) – 2012	(3,031)	(3,570)	(3,308)	(3,479)	(3,013)	(3,908)	(3,927)	(3,579)	(3,675)	(3,338)	(3,934)	(3,962)
Maximum load-following down capacity (MW) – 2006	(2,567)	(2,649)	(2,751)	(2,718)	(2,601)	(3,046)	(3,107)	(2,989)	(2,866)	(2,918)	(3,262)	(3,365)
Maximum Regulation Up capacity (MW) – 2012	260	261	270	257	280	361	383	287	291	319	350	344
Maximum Regulation Up capacity (MW) – 2006	202	198	191	198	201	226	244	239	238	262	273	278
Maximum Regulation Down capacity (MW) – 2012	(341)	(408)	(461)	(463)	(506)	(763)	(305)	(321)	(312)	(294)	(275)	(229)
Maximum Regulation Down capacity (MW) – 2006	(367)	(408)	(430)	(434)	(416)	(305)	(267)	(268)	(289)	(245)	(223)	(222)

Table A-5: Fall Hourly Results, full portfolio (load, wind and solar), all forecast errors, hours 1-12

	1	2	3	4	5	6	7	8	9	10	11	12
Maximum load-following up capacity (MW) – 2012	2,782	2,777	2,765	2,522	2,701	2,843	2,746	2,773	3,326	2,976	3,050	2,846
Maximum load-following up capacity (MW) – 2006	2,232	2,221	2,138	2,165	2,060	2,276	2,389	2,084	2,310	2,345	2,316	2,269
Maximum load-following down capacity (MW) – 2012	(2,904)	(3,004)	(2,724)	(2,845)	(2,699)	(2,960)	(2,794)	(3,210)	(3,103)	(2,879)	(2,661)	(3,058)
Maximum load-following down capacity (MW) – 2006	(2,268)	(2,280)	(2,275)	(2,132)	(2,171)	(2,344)	(2,509)	(2,396)	(2,228)	(2,145)	(2,129)	(2,058)
Maximum Regulation Up capacity (MW) – 2012	314	345	313	311	323	428	340	303	351	378	293	285
Maximum Regulation Up capacity (MW) – 2006	271	275	245	245	248	235	239	235	217	214	224	234
Maximum Regulation Down capacity (MW) – 2012	(252)	(275)	(257)	(281)	(274)	(297)	(333)	(372)	(407)	(328)	(352)	(427)
Maximum Regulation Down capacity (MW) – 2006	(233)	(263)	(244)	(240)	(249)	(256)	(259)	(263)	(304)	(335)	(323)	(371)

Table A-6: Fall Hourly Results, full portfolio (load, wind and solar), all forecast errors, hours 13-24

	13	14	15	16	17	18	19	20	21	22	23	24
Maximum load-following up capacity (MW) – 2012	2,959	2,917	3,027	2,938	2,735	3,017	3,056	2,733	2,699	2,740	3,011	2,726
Maximum load-following up capacity (MW) – 2006	2,287	2,225	2,432	2,418	2,185	2,209	2,680	2,216	2,185	2,294	2,433	2,314
Maximum load-following down capacity (MW) – 2012	(2,579)	(2,904)	(3,176)	(2,890)	(3,172)	(3,247)	(3,031)	(2,787)	(2,820)	(2,720)	(2,992)	(2,894)
Maximum load-following down capacity (MW) – 2006	(2,048)	(2,132)	(2,133)	(2,249)	(2,131)	(2,217)	(2,307)	(2,060)	(2,232)	(2,305)	(2,482)	(2,420)
Maximum Regulation Up capacity (MW) – 2012	281	273	286	319	378	404	288	297	339	307	316	323
Maximum Regulation Up capacity (MW) – 2006	221	225	222	217	232	236	233	236	256	262	259	272
Maximum Regulation Down capacity (MW) – 2012	(392)	(377)	(454)	(388)	(376)	(515)	(390)	(347)	(257)	(275)	(329)	(247)
Maximum Regulation Down capacity (MW) – 2006	(420)	(440)	(406)	(402)	(395)	(263)	(270)	(254)	(248)	(230)	(230)	(232)

Table A-7: Winter Hourly Results, full portfolio (load, wind and solar), all forecast errors, hours 1-12

	1	2	3	4	5	6	7	8	9	10	11	12
Maximum load-following up capacity (MW) – 2012	2,338	2,753	2,344	2,698	2,532	2,541	2,838	2,598	2,631	2,700	2,803	2,710
Maximum load-following up capacity (MW) – 2006	1,999	2,037	1,984	2,132	2,171	2,095	2,370	2,015	2,153	2,168	2,048	2,097
Maximum load-following down capacity (MW) – 2012	(2,849)	(2,934)	(2,533)	(2,324)	(2,669)	(2,533)	(2,598)	(2,480)	(2,554)	(2,468)	(2,574)	(2,398)
Maximum load-following down capacity (MW) – 2006	(2,176)	(2,124)	(2,120)	(2,051)	(2,095)	(2,107)	(2,138)	(1,926)	(1,897)	(1,813)	(1,940)	(1,875)
Maximum Regulation Up capacity (MW) – 2012	319	284	304	334	327	448	255	263	335	300	298	302
Maximum Regulation Up capacity (MW) – 2006	274	249	249	248	235	230	240	237	240	233	222	231
Maximum Regulation Down capacity (MW) – 2012	(288)	(298)	(265)	(277)	(293)	(306)	(349)	(338)	(357)	(442)	(378)	(383)
Maximum Regulation Down capacity (MW) – 2006	(237)	(248)	(246)	(251)	(249)	(264)	(262)	(263)	(270)	(353)	(314)	(327)

Table A-8: Winter Hourly Results, full portfolio (load, wind and solar), all forecast errors, hours 13-24

	13	14	15	16	17	18	19	20	21	22	23	24
Maximum load-following up capacity (MW) – 2012	2,597	2,619	3,000	2,688	2,689	3,063	2,683	2,608	2,646	2,516	2,647	2,647
Maximum load-following up capacity (MW) – 2006	2,171	1,965	2,256	2,175	2,146	2,624	2,193	2,131	2,071	2,222	2,285	2,201
Maximum load-following down capacity (MW) – 2012	(2,424)	(2,666)	(2,613)	(2,448)	(3,013)	(3,094)	(2,655)	(2,380)	(2,298)	(2,482)	(2,754)	(2,612)
Maximum load-following down capacity (MW) – 2006	(1,837)	(2,069)	(1,989)	(1,947)	(2,097)	(2,424)	(2,244)	(1,907)	(1,934)	(1,998)	(2,303)	(2,204)
Maximum Regulation Up capacity (MW) – 2012	284	296	302	328	397	474	326	303	304	315	308	329
Maximum Regulation Up capacity (MW) – 2006	238	234	229	232	219	220	233	247	260	263	265	273
Maximum Regulation Down capacity (MW) – 2012	(397)	(377)	(407)	(391)	(374)	(363)	(304)	(313)	(296)	(274)	(297)	(289)
Maximum Regulation Down capacity (MW) – 2006	(306)	(320)	(319)	(336)	(322)	(289)	(280)	(279)	(261)	(232)	(233)	(240)

APPENDIX A-2: Additional sensitivity results from the operational requirements simulations

This appendix provides additional sensitivity results from the operational requirements simulations. As noted in Section 3, these include:

- Requirements by renewable technology, in which the simulations are re-run with and without particular technologies to distinguish the impact of incremental solar resources only, incremental wind resources only, and the full renewable portfolio; and the

- Impact of forecast error and variability, in which the simulations are re-run to distinguish the differential effect of these factors.

As with Section 3, the focus in this appendix is on Summer 2012 results; showing one season of such results is sufficient to characterize the relationships among the variables being analyzed.

The figures and graphs in this appendix follow the conventions noted in Sections 2 and 3 of the report. In all instances, references to the operational requirements in 2006 refer to the *simulated* operational requirements for the base year. Also, the results reported in the following tables and figures as *maximums* are the 95th percentile occurrence for a particular hour.[2]

A.1 Load Following Results for Summer 2012

A.1.1 Requirements by renewable technology

As noted in Section 2, the impact of variable energy resources can be differentiated by technology using the statistical simulation methodology. The results of such sensitivity analyses are presented here to show the relative impact of load and each renewable technology being modeled on load following by hour. The difference between wind and solar is in part a function of the capacity of each technology type in the portfolio (i.e., how much energy is being obtained in each hour from each technology), and also of their particular variability and forecast error characteristics. The results are not intended to be indicative of how to construct a renewable portfolio to minimize operational impacts; that is, there is not sufficient information in these results to determine how to isolate the relative impacts of wind and solar across all the operational requirements. As with the results shown above, the results here assume all forecast errors.

Figures A-9 and A-10 show the hourly maximum results due to (a) load, (b) load plus solar, (c) load plus wind, and (d) load plus wind plus solar. Obviously, in the off-peak hours, wind is the driver of the incremental operational requirements.

[2] That is, excluding the 5% highest results from the simulations.

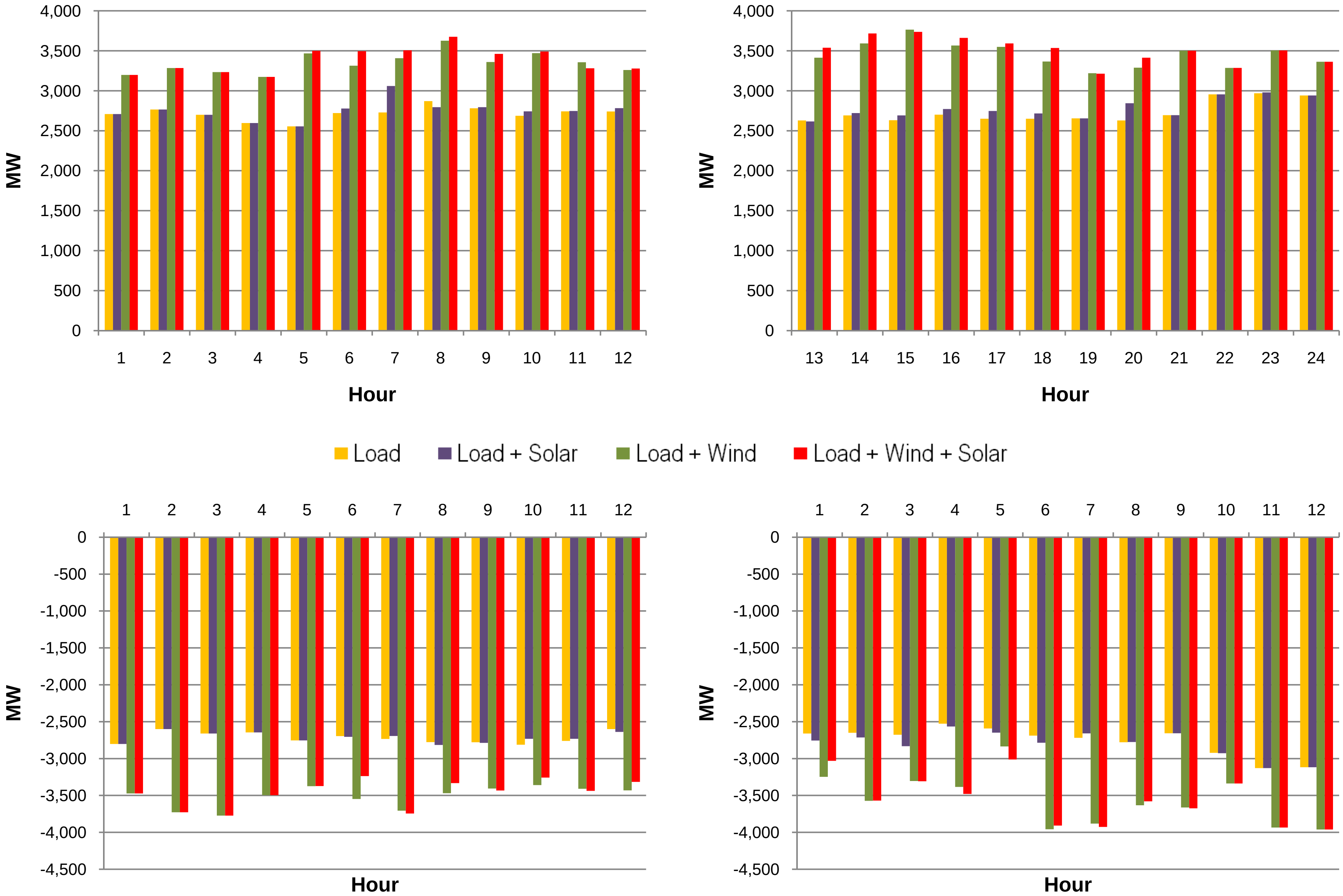


Figure A-9: 2012 Summer Load Following Maximum Hourly Requirement by Technology

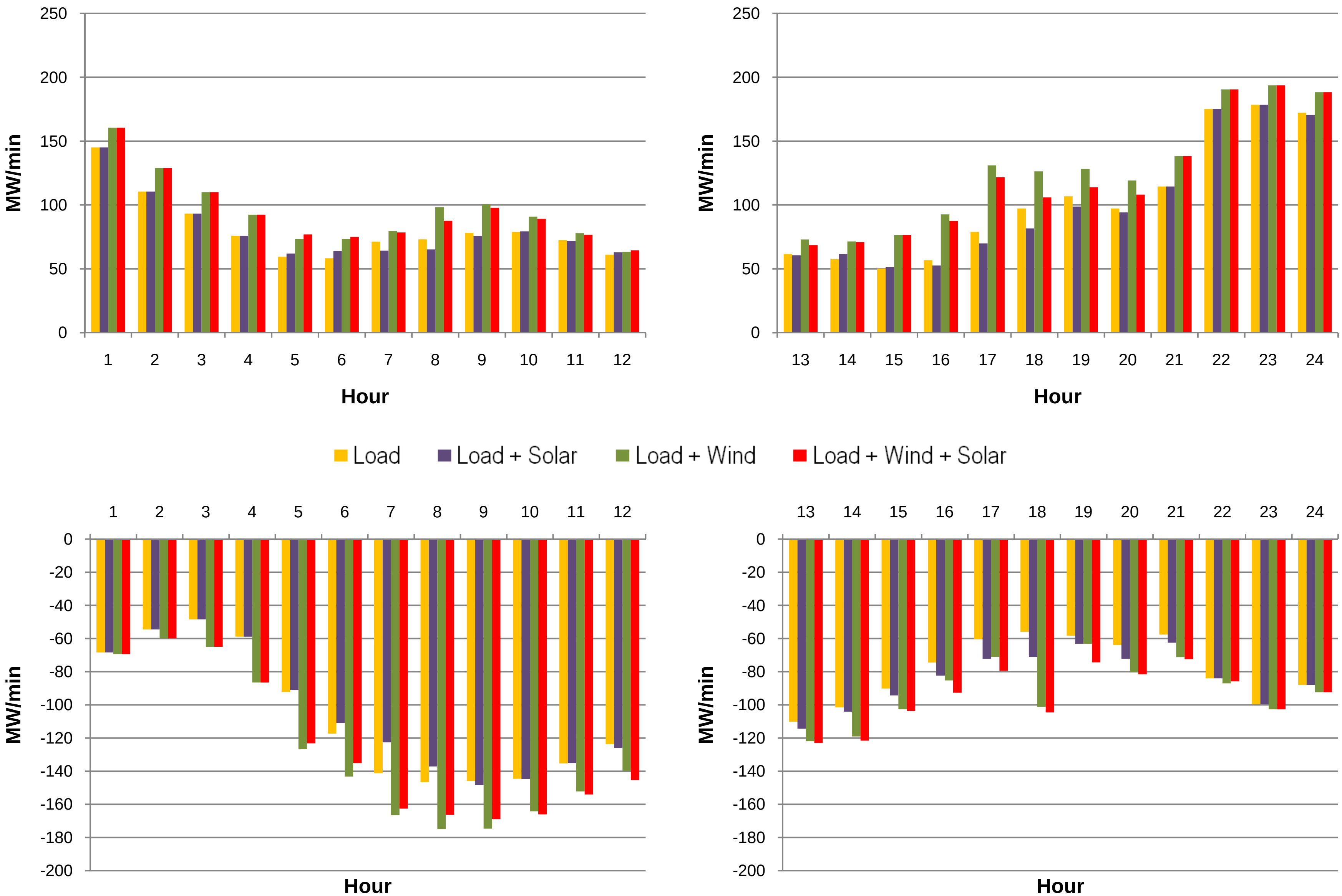


Figure A-10: 2012 Summer Load Following Up and Down Maximum Hourly Ramp Rate by Technology

A.1.2 Impact of forecast error and variability

In the hour-ahead time frame, forecast error is the more significant contributor to incremental load following requirements due to variable energy resources than their inherent variability. As noted, the simulation can take account of this difference by altering the statistical parameters of the distribution of forecast errors – including removing them altogether, at which point the residual impact on load following is due to variability alone. For comparison, this section compares the results of including all forecast errors and no errors; specific improvements in forecast errors were not evaluated in this study but will be explored in subsequent analysis.

The two components of Figure A-11shows an aggregate "all hours" result that compares the load following up and down MW calculated in each hour with and without errors for all hours in the season. The aggregate quantity without errors is presented as a proportion of the aggregate quantity with errors. As shown, in each case, variability contributes 19 percent of the total requirement, with forecast errors providing the remaining 81 percent. Figures A-12 and A-13 then show this result by operating hour. The hourly result shows in which hours improvements in forecasting are likely to provide the highest benefit.

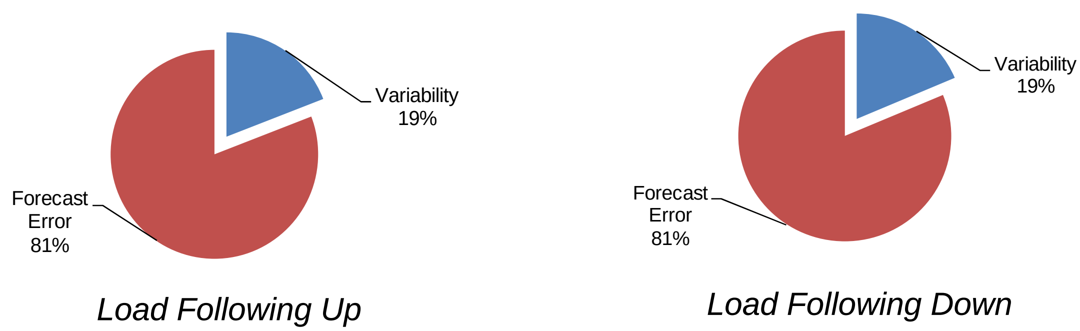


Figure A-11: Aggregate Contribution of Variability and Forecast Error to the Summer 2012 Load Following Requirement

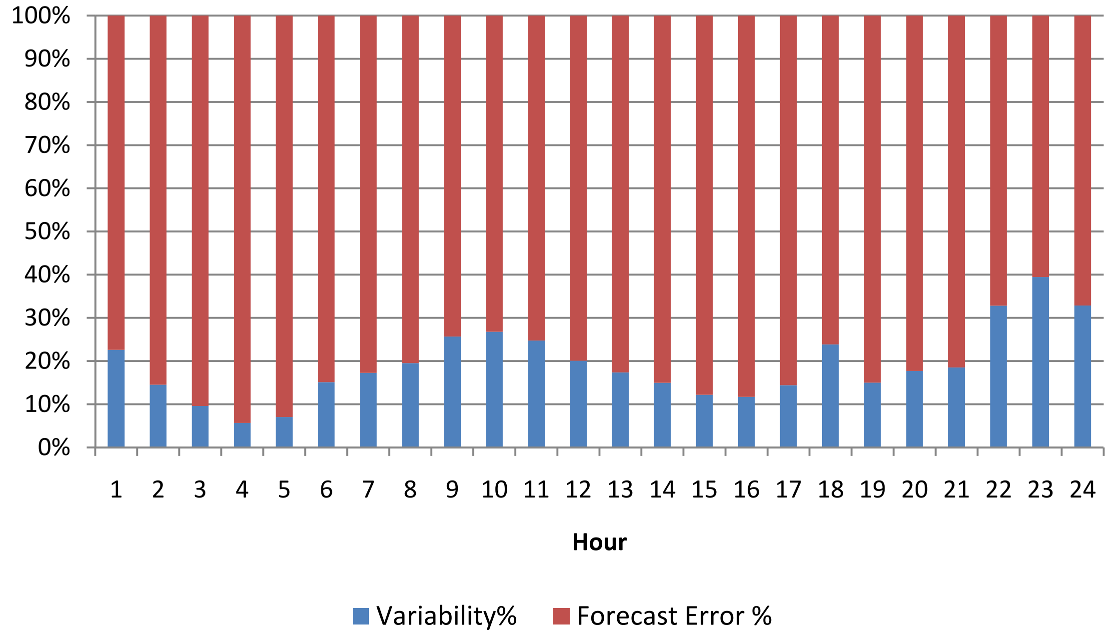


Figure A-12: Effect of Forecast Error and Variability on Load Following Up (Load & Wind & Solar) by Hour, Summer 2012

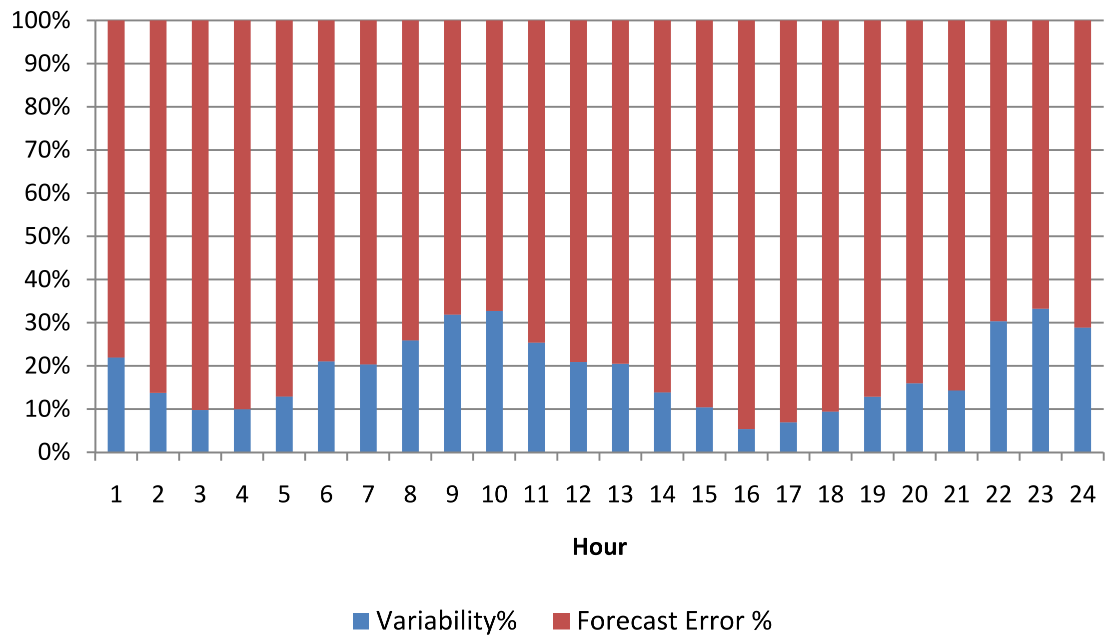


Figure A-14: Effect of Forecast Error and Variability on Load Following Down (Load & Wind & Solar) by Hour, Summer 2012

A further representation of this result is shown in Figure A-14, which compares the maximum load following capacity results for load-only requirements assuming all (load forecast) errors to portfolio requirements with wind and solar forecast errors eliminated and then to portfolio requirements with wind and solar forecast errors included.

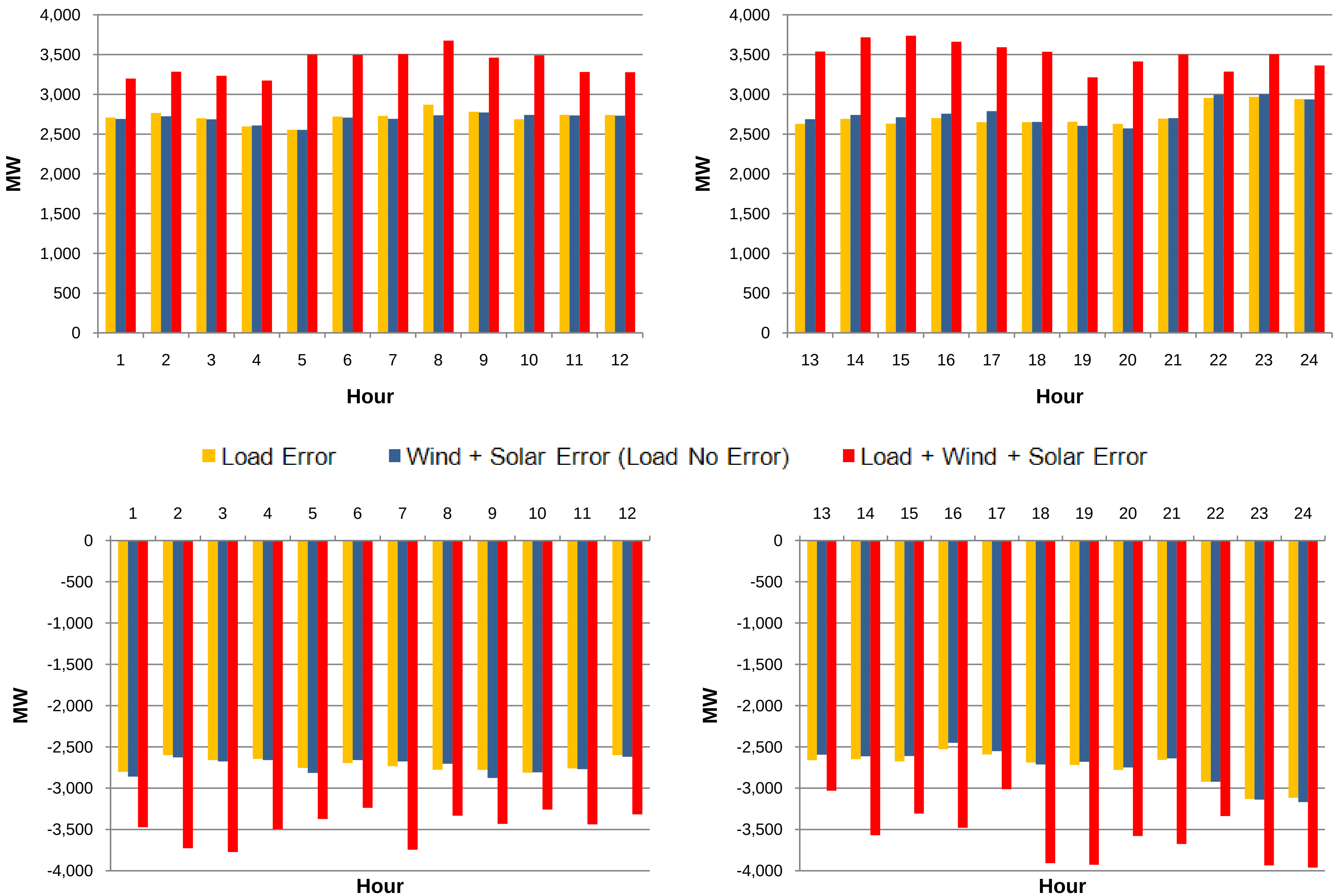


Figure A-13: Maximum Hourly Load-Following Capacity Requirement with Variations in Forecast Error Assumptions

The sensitivity analysis of forecast error provides a quantitative measure of how improvements in the hour-ahead forecast (and hence in periods further forward in time) can reduce the ramp range that the ISO will need to deploy within the hour. A 10 percent improvement in forecast error could result in a reduction in several hundred MW of load following capability in the upward and downward direction. The results point to the particular hours – morning and evening ramps – where such forecast improvements would have the most value. However, the ISO has not in this study quantified specific reductions in forecast error or the potential dispatch cost reductions. Subsequent studies may provide such information.

A.2 Regulation Results for Summer 2012

A.2.1 Requirements by renewable technology

As with load following, the impact of variable energy resources on regulation can be differentiated by technology using the statistical simulation methodology. These sensitivity results are presented here to show the relative impact of load and each renewable technology (at the capacity being modeled) on regulation by hour. Again, the results are not intended to be indicative of how to construct a renewable portfolio to minimize operational impacts. The results here assume all forecast errors and variability for load, but only the variability data captured for wind and solar. Hence, the results are not indicative of how variable energy resource forecast error affects the operational requirements in this time frame.

Figure A-15 shows the hourly maximum Regulation capacity results with sensitivity cases that model (a) load only for 2012, (b) load plus solar, (c) load plus wind, and, finally, (d) load plus wind plus solar, which is the case shown in Section 3. The results show that wind resources largely drive the increases in regulation up requirements in the morning hours, while solar resources barely increase those requirements compared to the load-only case. In the afternoon hours, solar resources drive additional requirements in the mid-afternoon hours, when wind is hardly creating any additional requirements until hours 18-19. For regulation down, solar has a more significant effect than wind in Hours 8-9, then wind significantly drives the maximum requirements in the mid-afternoon, with a peak in Hour 18. Figure A-16 shows these comparative results for the hourly maximum results for Regulation ramp rates.

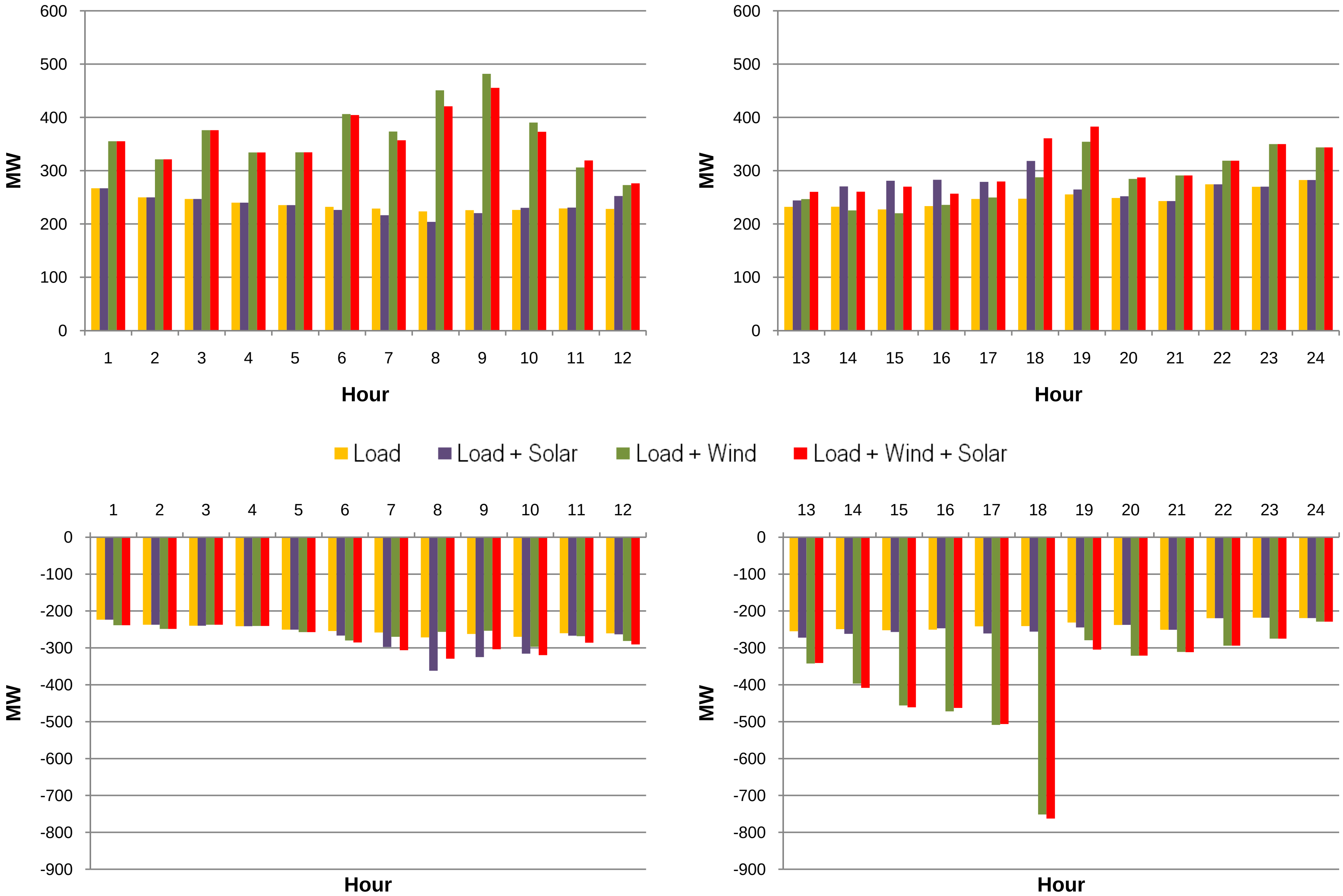


Figure A-14: Regulation Capacity Requirements by Technology by Hour, Summer 2012

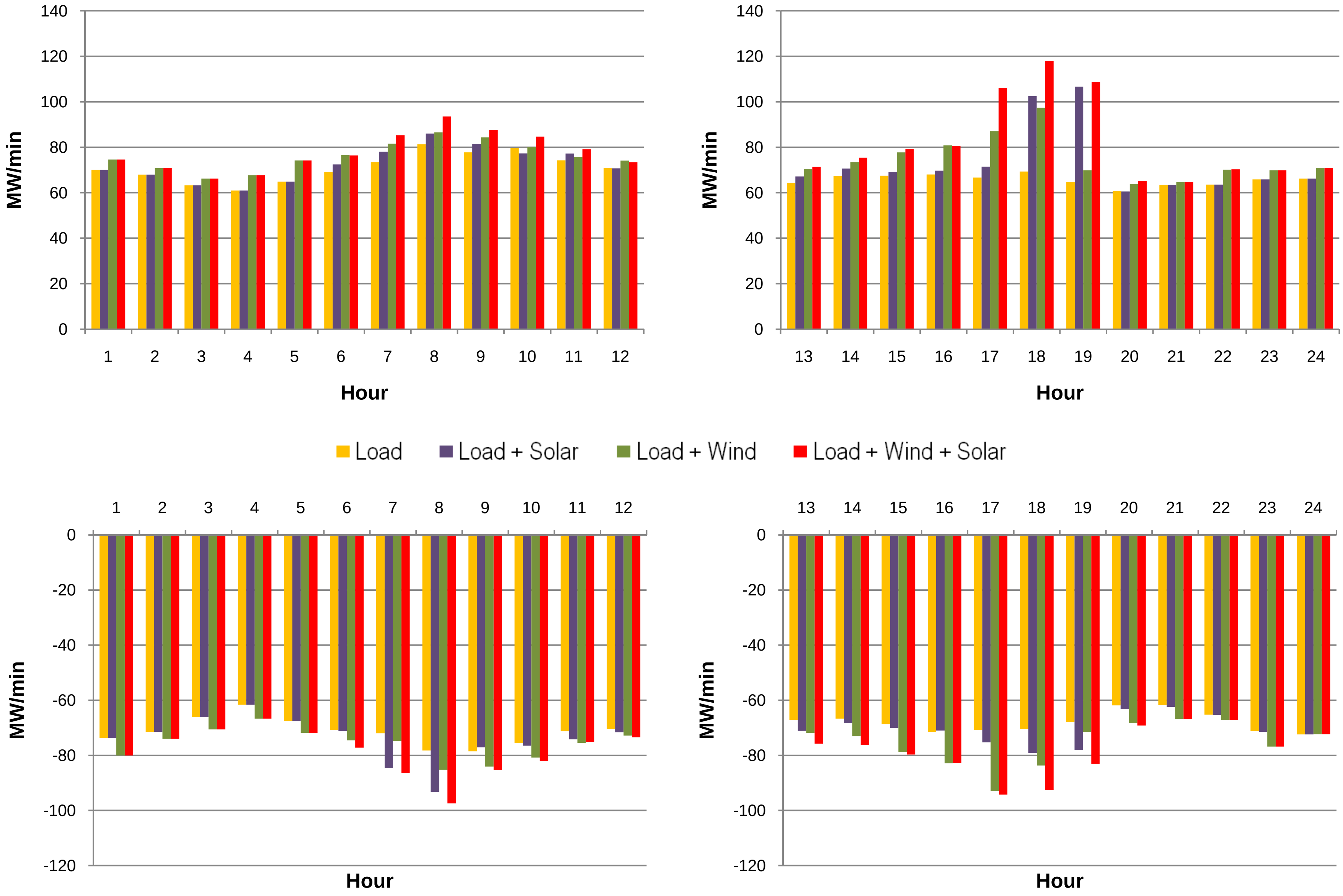


Figure A-15: Summer 2012 Regulation Ramp Rate by Technology

A.2.2 Impact of forecast error and variability

In the hour-ahead time frame, variability is the more significant contributor to the incremental regulation requirements due to variable energy resources than forecast error. However, unlike the load following simulation, the model does not include short-term forecast errors for wind and solar resources; in current practice, the ISO uses a persistence forecast for short-term dispatch, which was not sampled by the Monte Carlo simulation but rather held static in the analysis. Hence, only load forecast errors are evaluated when isolating forecast error from variability, and the impact of wind and solar resources on Regulation is based entirely on their variability within the five-minute dispatch interval.

Figure A-17 shows an aggregate "all hours" result that compares the regulation up and down MW calculated in each hour with and without errors for all hours in the season. The aggregate quantity without errors is presented as a proportion of the aggregate quantity with errors. As shown, in each case, variability contributes a little over 60 percent of the total requirement; with (load) forecast errors providing the remaining percent. Figure A-18 and Figure A-19 then shows this result by operating hour. The hourly results show which hours improvements in forecasting are likely to provide the highest benefit.

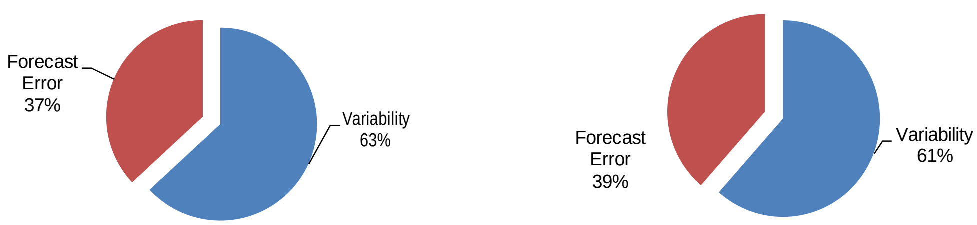


Figure A-16: Aggregate Contribution of Variability and Forecast Error to the Summer Regulation Requirement

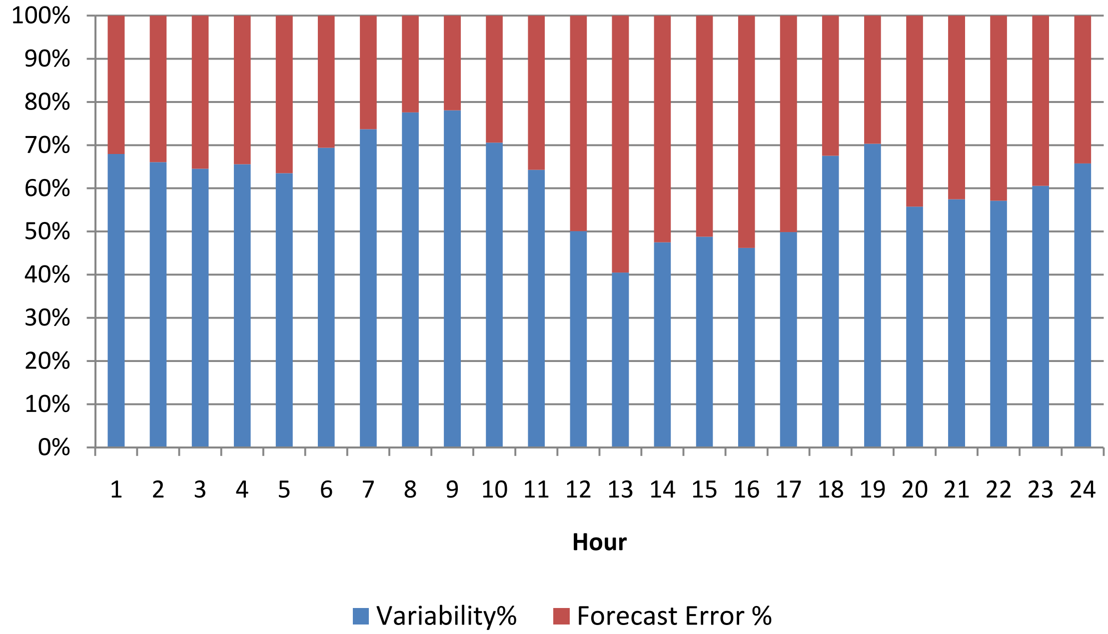


Figure A-17: Effect of Forecast Error and Variability on Regulation Up (Load & Wind & Solar) by Hour, Summer 2012

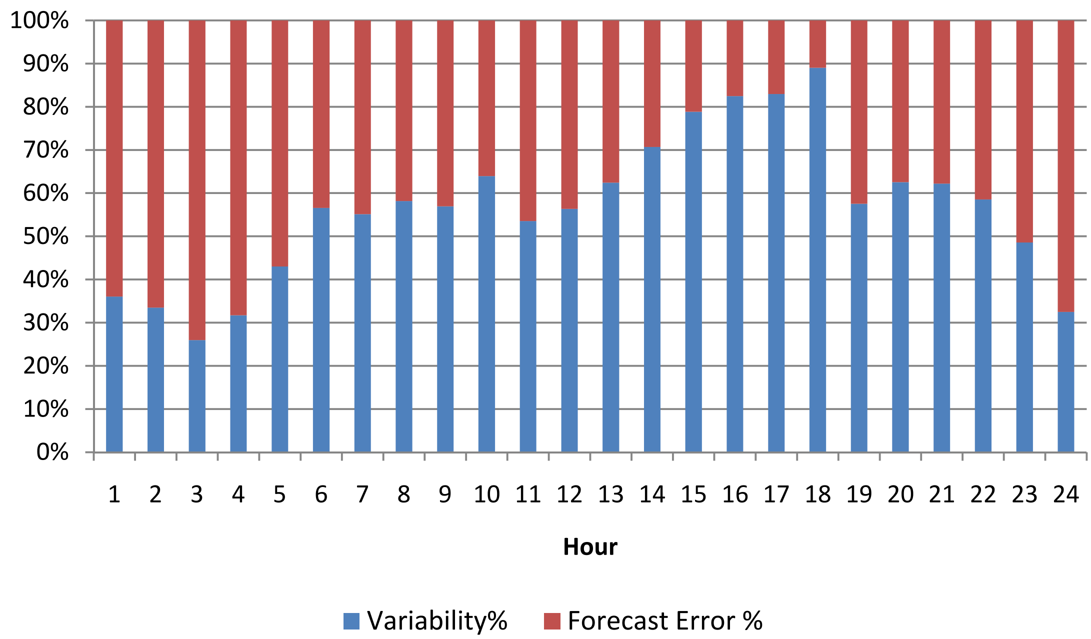


Figure A-18: Effect of Forecast Error and Variability on Regulation Down (Load & Wind & Solar) by Hour, Summer 2012

APPENDIX B Additional Fleet Capability Analysis Results

Section 4 discussed the load-following and regulation capability of the fleet for the summer season based on market data from April 1, 2009 to June 30, 2010. This appendix gives the historical capability for all the seasons.

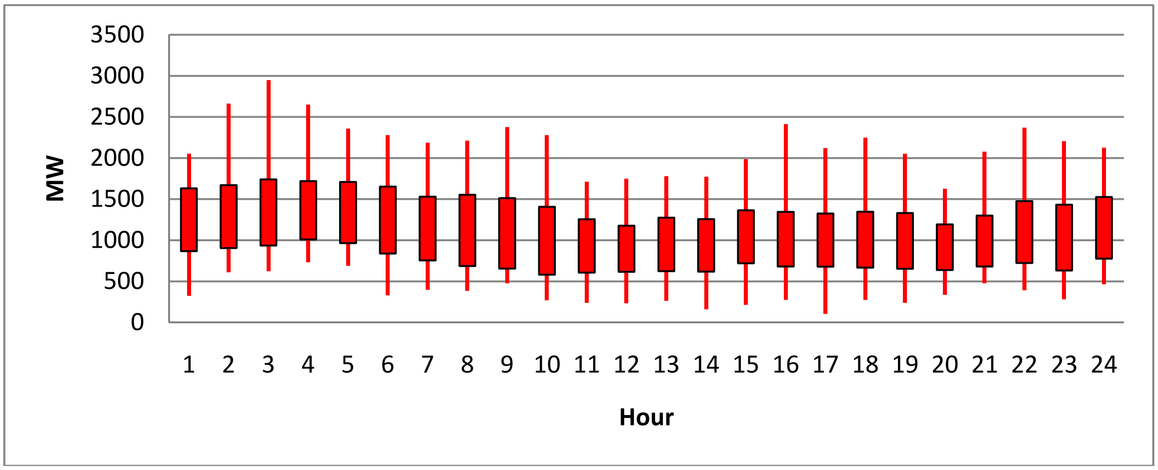


Figure B-1: Fall 5-Minute Load Following Up Capability: Sep2009-Nov2009

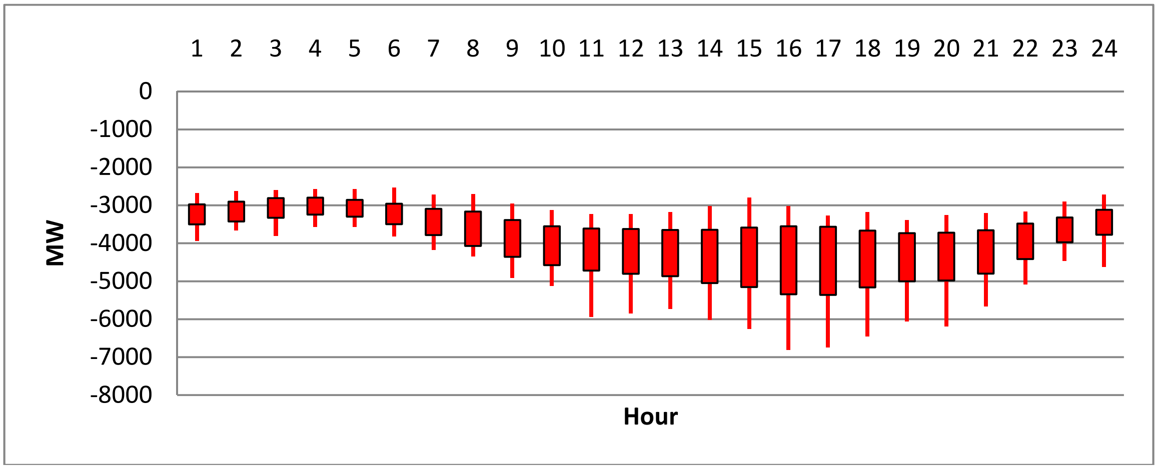


Figure B-2: Fall 5-Minute Load Following Down Capability: Sep2009-Nov2009

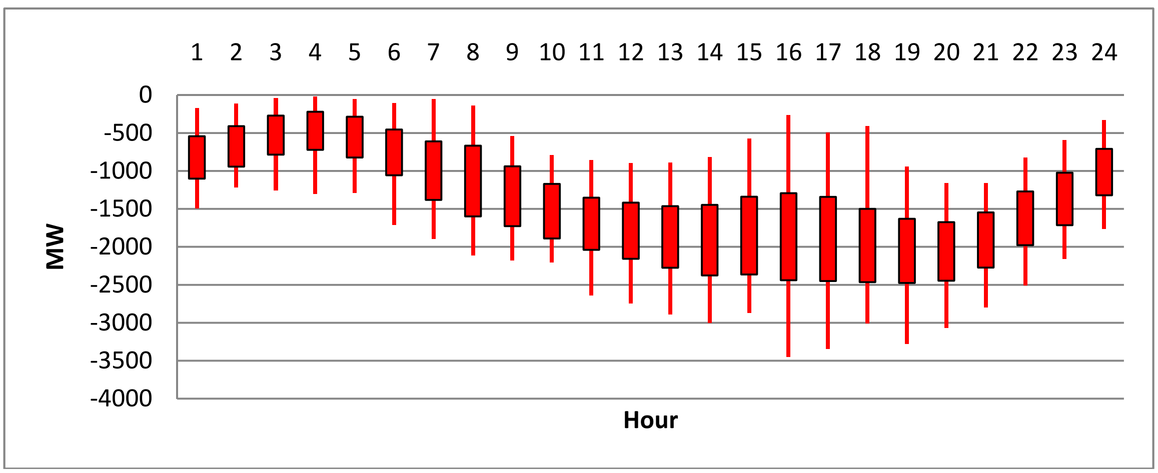


Figure B-3: Fall 5-Minute Load Following Down Capability (To Self Schedule): Sep2009-Nov2009

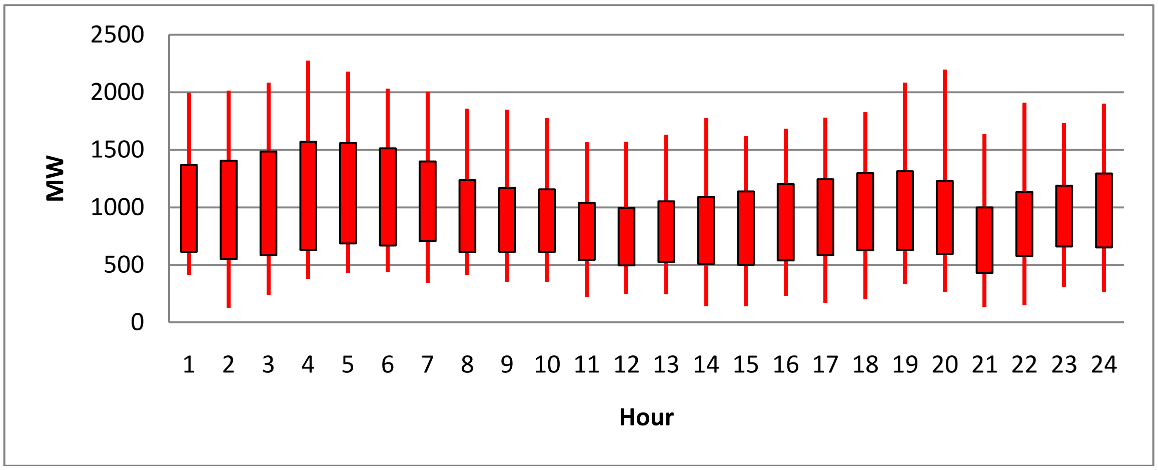


Figure B-4: Spring 5-Minute Load Following Up Capability: Mar-May, 2009-2010

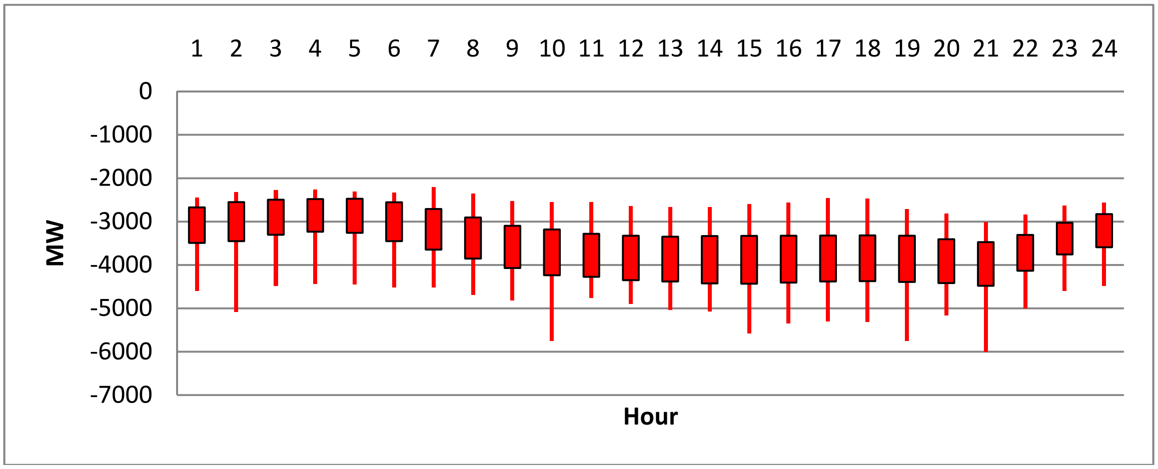


Figure B-5: Spring 5-Minute Load Following Down Capability: Mar-May, 2009-2010

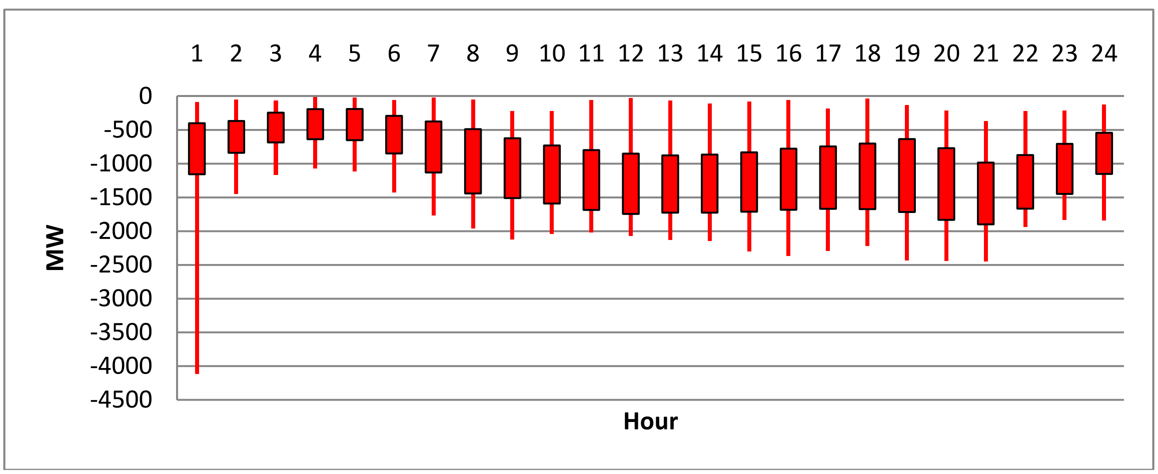


Figure B-6: Spring 5-Min Load Following Down Capability (To Self Schedule): Mar-May, 2009-2010

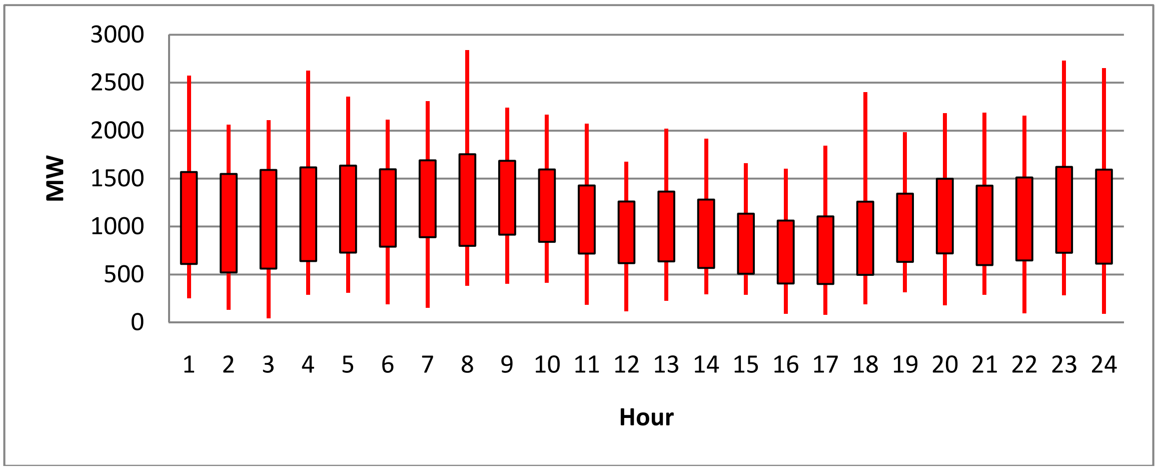


Figure B-7: Summer 5-Minute Load Following Up Capability: Jun2009-Aug2009, Jun2010

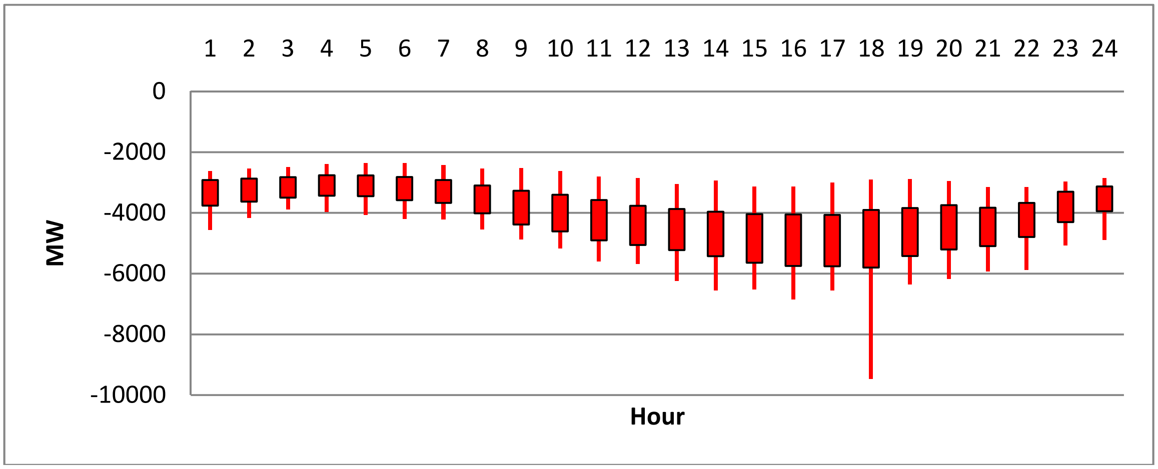


Figure B-8: Summer 5-Minute Load Following Down Capability: Jun2009-Aug2009, Jun2010

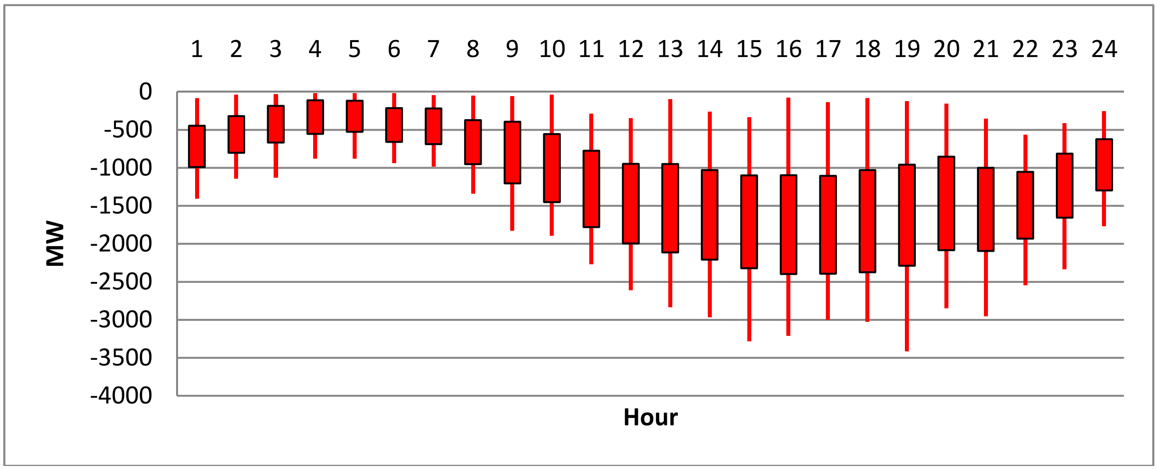


Figure B-9: Summer 5-Min Load Following Down Capability (To Self Schedule): Jun09-Aug09, Jun10

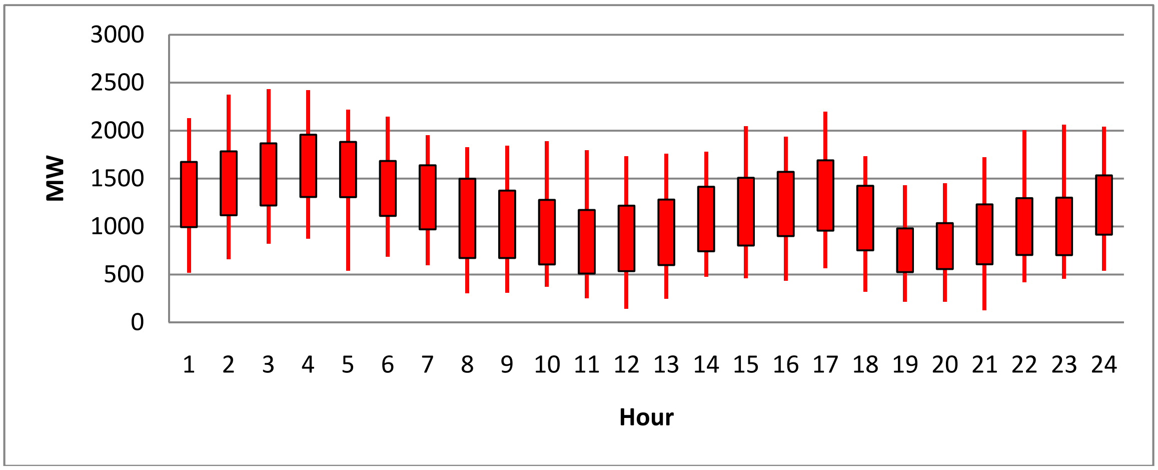


Figure B-10: Winter 5-Minute Load Following Up Capability: Dec2009-Feb2010

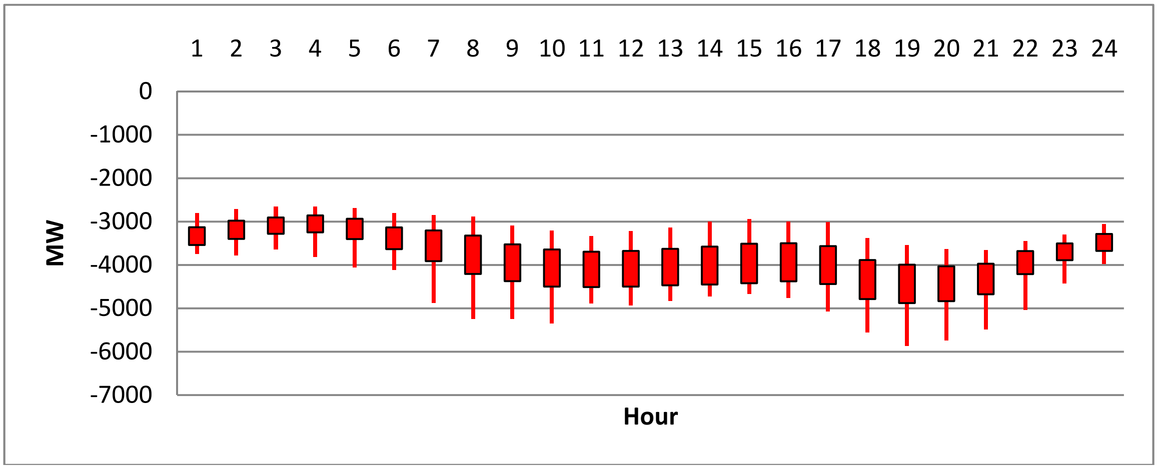


Figure B-11: Winter 5-Minute Load Following Down Capability: Dec2009-Feb2010

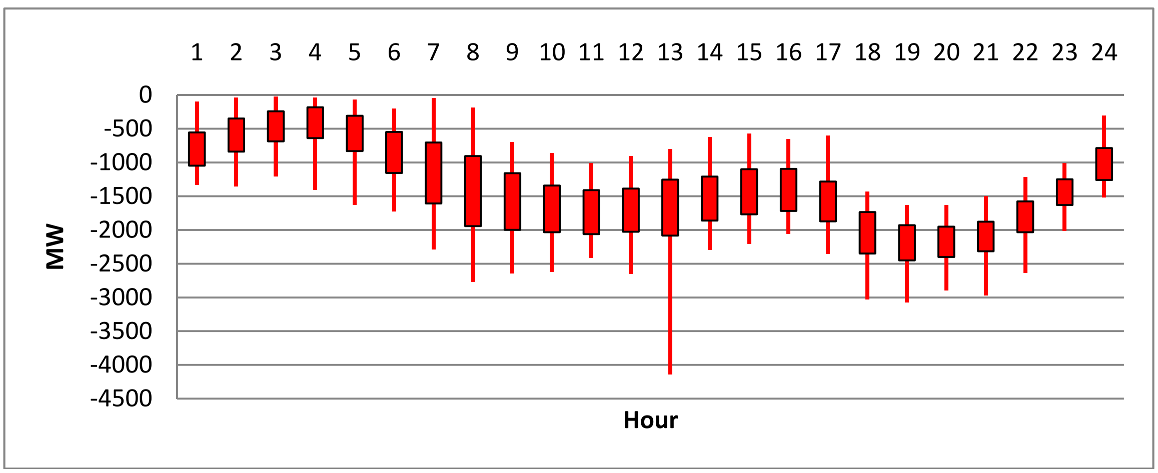


Figure B-12: Winter 5-Minute Load Following Down Capability (To Self Schedule): Dec2009-Feb2010

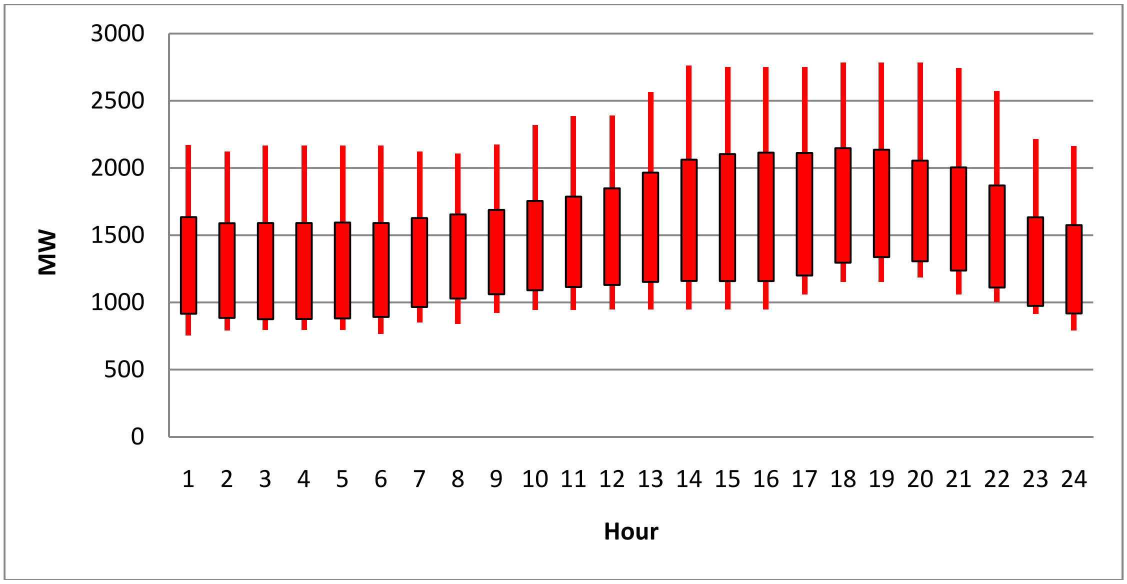


Figure B-13: Fall Regulation Up, 5-Min. Ramp Capability of Bid MW: Sep2009-Nov2009

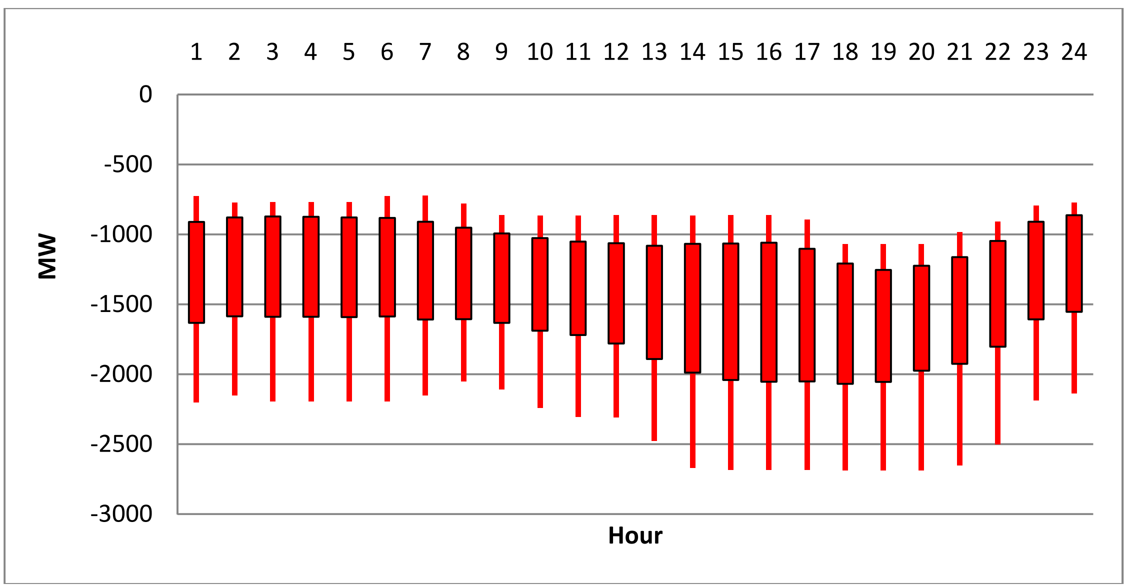


Figure B-14: Fall Regulation Down, 5-Min. Ramp Capability of Bid MW: Sep2009-Nov2009

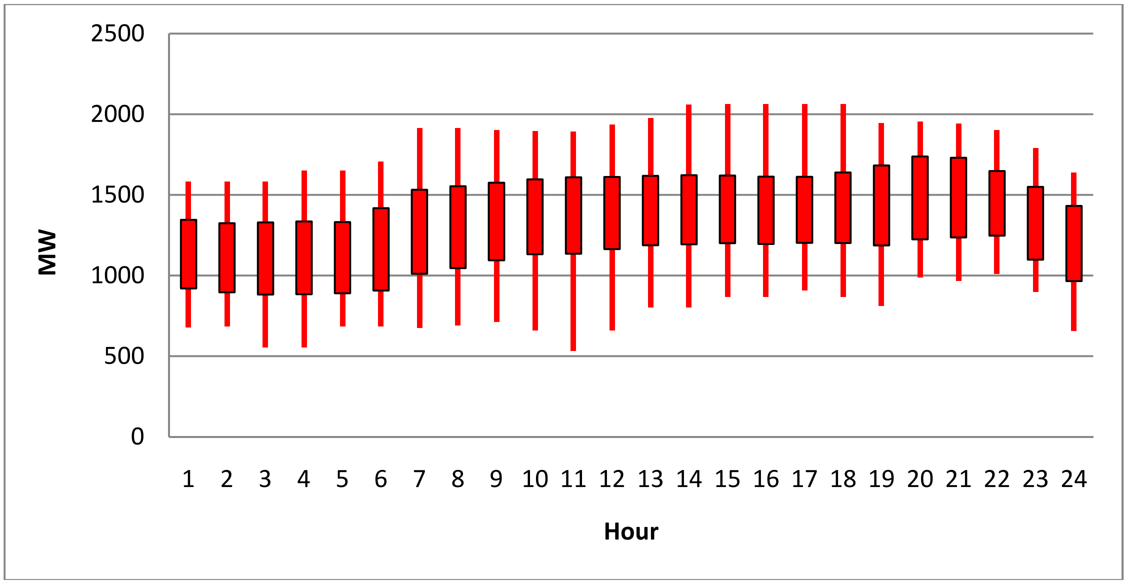


Figure B-15: Spring Regulation Up, 5-Min. Ramp Capability of Bid MW: Mar-May, 2009-2010

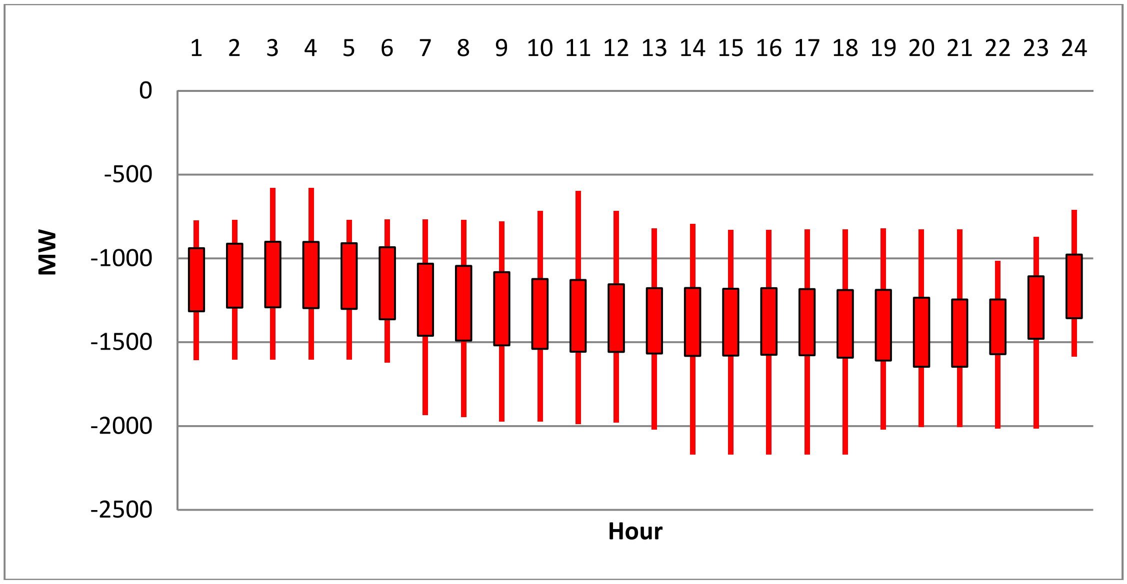


Figure B-16: Spring Regulation Down, 5-Min. Ramp Capability of Bid MW: Mar-May, 2009-2010

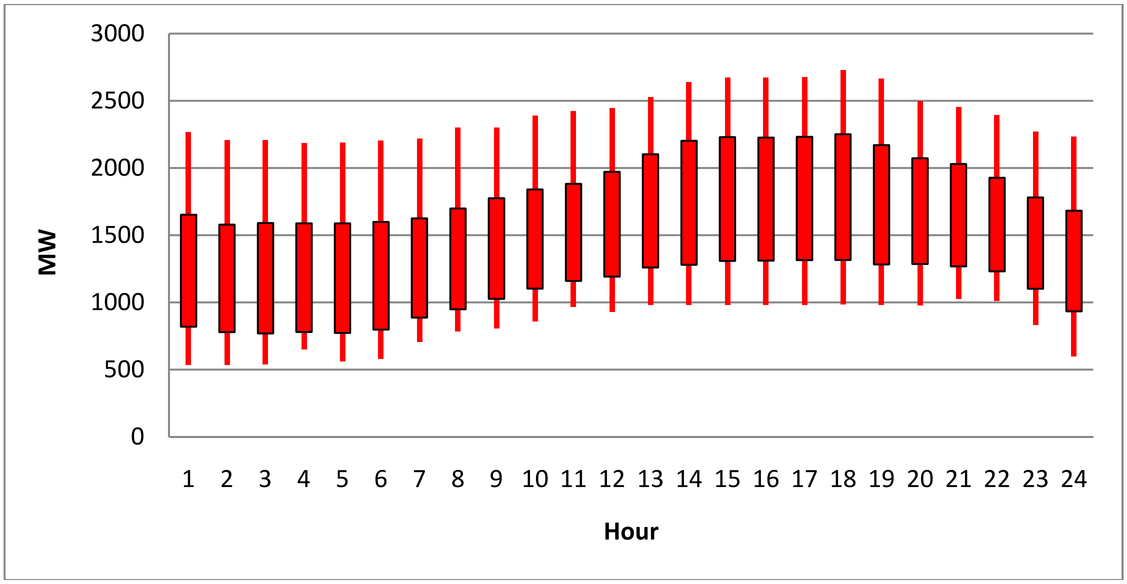


Figure B-17: Summer Regulation Up, 5-Min. Ramp Capability of Bid MW: Jun2009-Aug2009, Jun2010

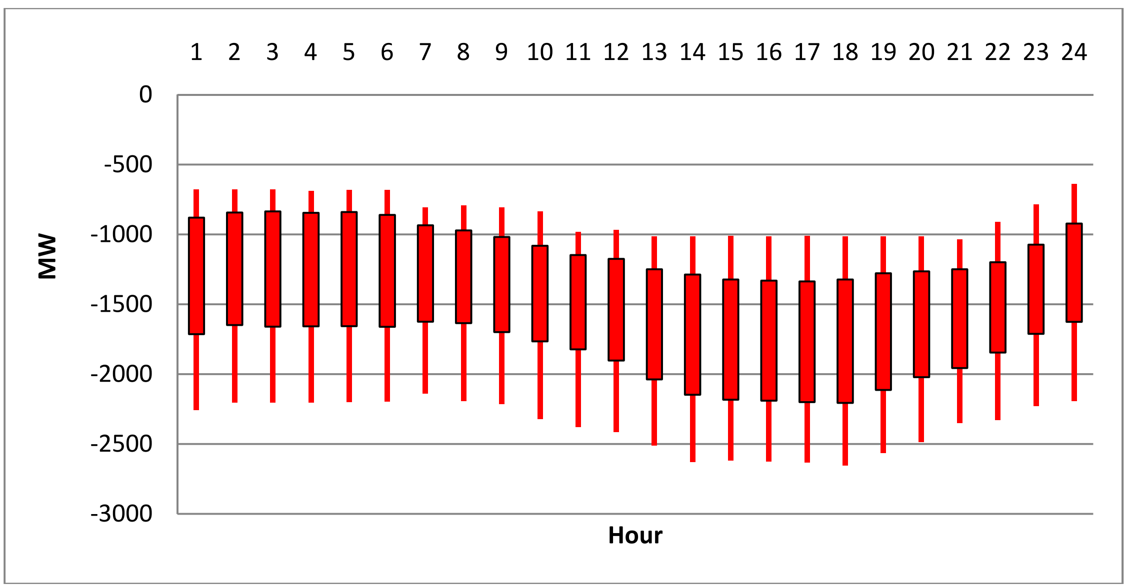


Figure B-18: Summer Regulation Down, 5-Min. Ramp Capability of Bid MW: Jun2009-Aug2009, Jun2010

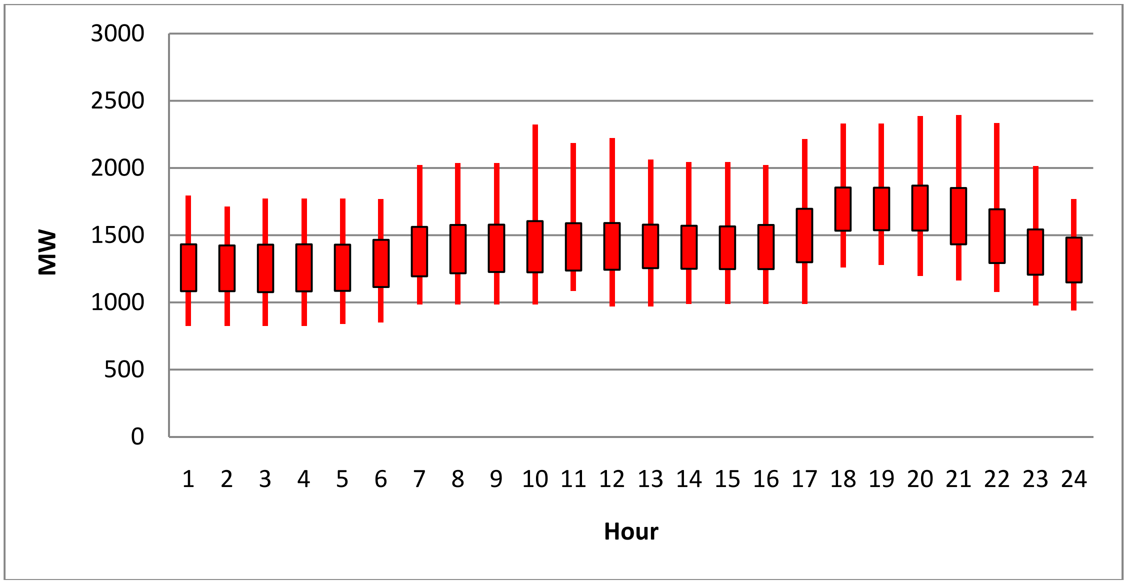


Figure B-19: Winter Regulation Up, 5-Min. Ramp Capability of Bid MW: Dec2009-Feb2010

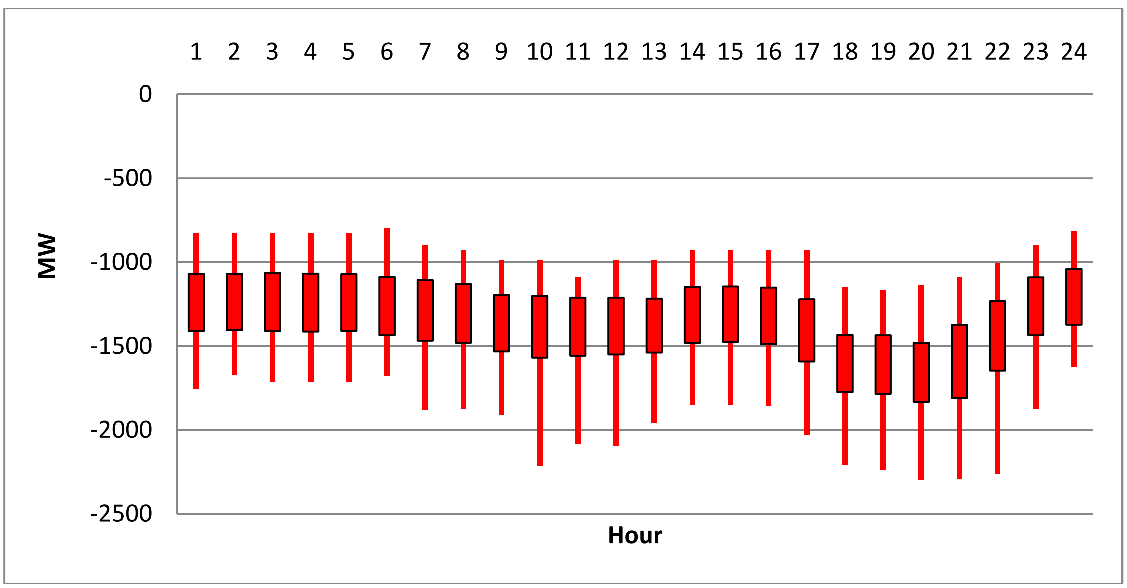


Figure B-20: Winter Regulation Down, 5-Min. Ramp Capability of Bid MW: Dec2009-Feb2010

APPENDIX C Additional Production simulation Results

C.1 Stochastic Sequential Simulation Results

C.1.1 Overview

For selected days, the ISO adopted a sequential approach to the simulations: first, conducting the day-ahead and hour-ahead simulations, then "freezing" the resulting unit commitment for simulation of the "real-time" dispatch on a five-minute time-step. This methodology is already described in the Technical Appendix. It is not practical to run the sequential, stochastic simulation, and in particular, the 5-minute real-time simulations for the whole year due to the computational burden that is involved. Therefore, it is necessary to focus these simulations only for some periods of interest. This section of the appendix describes the overall process that was used in the sequential, stochastic simulation of interesting days.

A number of stochastic simulations are required for determining the real-time operational capability of the system. These simulations are listed below.

- Annual Day Ahead (DA), stochastic
- Monthly Hour Ahead (HA), stochastic
- Monthly Real Time Hourly (RT-H), stochastic
- Daily Real Time 5 minute (RT-5), stochastic

Each simulation provides insights into the system operation and helps guide the selection of time periods for the following steps. At each step of the process the system was examined for the following operational issues:

- Overgeneration, or dump energy
- Regulation down violations (regdn)
- Regulation up violations (regup)
- Spinning Reserve violations
- Non-spinning Reserve violations

In the results presented in Section 5 of the report, overgeneration and regulation down violations are combined together (and called overgeneration) since they both represent conditions where instantaneous generation is more than load.

C.2 Stochastic Simulation

The day-ahead (DA) hourly, stochastic simulation was performed first. This simulation showed that most of the over generation occurred in May and the surrounding months Figure C-1 shows the monthly over generation from the initial deterministic case (imports 100% firm) and the Day Ahead stochastic simulation. There were no significant other violations (regulation up and spin) in these simulations. Therefore, subsequent simulations focused on four months - April, May, June and July.

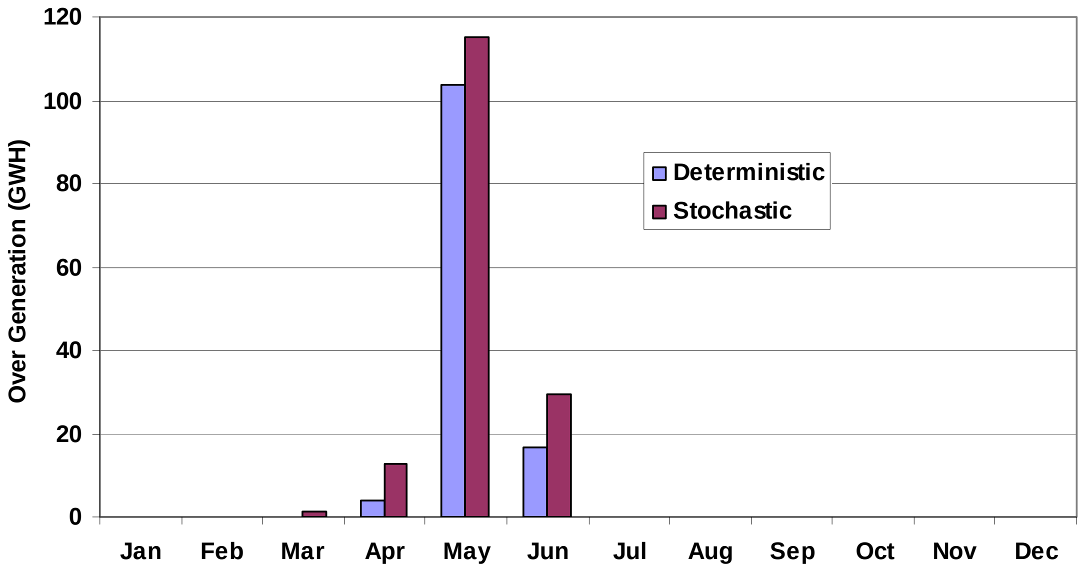


Figure C-1: Monthly over generation

With the unit commitment of long-start units from the DA simulation frozen, the hour-ahead, stochastic (hourly) simulations were performed for the four months. Both the day-ahead and hour-ahead simulations commit and dispatch to the forecasted load for 100 draws of the load forecast. Also, the wind generation in the commitment and dispatch are the same in each one the 100 iterations. Therefore, there is no uncertainty in load and wind generation in the day-ahead and hour-ahead stochastic simulations. The end-result of the day-ahead and hour-ahead stochastic simulation is a set of unit commitment for long and medium-start generators for the 100 iterations.

In order to evaluate the impact of uncertainty in load and wind generation forecasts, the unit commitment obtained from the HA market simulation (for each one of the 100 forecasts) was used to dispatch the system with actual hourly loads and hourly actual wind generation. In this real-time, hourly simulation (RT-H) simulation, only quick starts were allowed to be committed in addition to the long and medium-start units. Figure C-2 shows the monthly over generation results for the selected months, including the RT-H simulations. The month of May accounts for 80% of the annual over generation in the RT-H simulation. Figure C-3 shows the operating issues from each day from the DA, HA and RT-H simulations for the month of May. The over generation plus regulation down shortages for the RT-H simulations are shown in the last column. It should be reiterated that the over generation and regulation down violations in this simulation are due to the uncertainty in load and wind generation forecasts as modeled in the stochastic process. The RT-H simulation does not capture the impact of variability in load and wind generation since these simulations are done at an hourly time scale. The real-time, 5-minute simulations are used to capture the operational impacts of variability. This is discussed next.

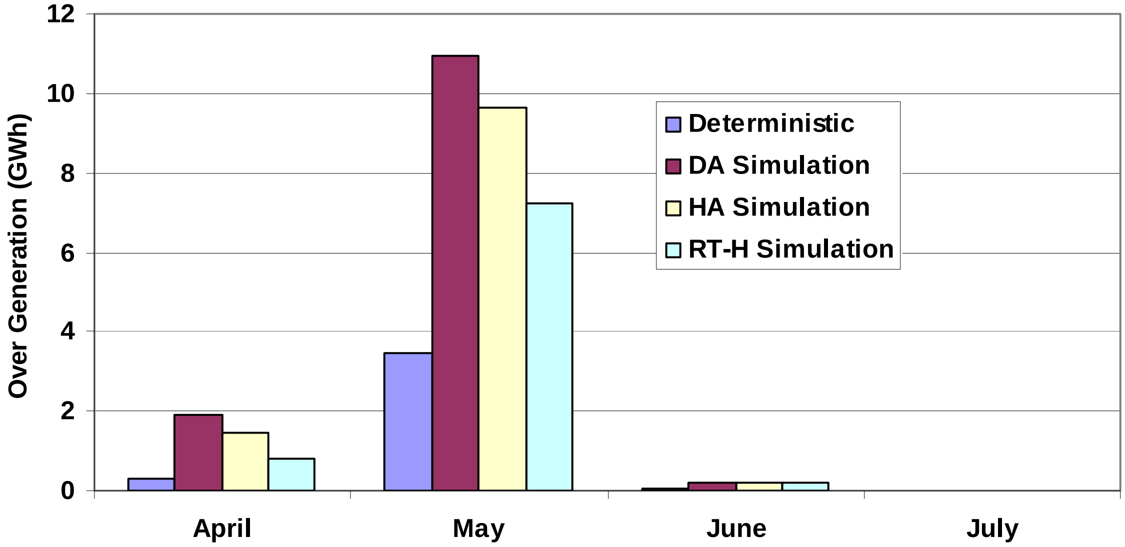


Figure C-2: Monthly over generation, imports 50% firm

From the RT-H simulations, it was decided to examine May 28th for the impact of variability in load and wind generation. Table C-1 shows the over generation results of the 5-minute (RT-5) simulation as well as the RT-H simulation. The overgeneration is higher in the RT-5 simulation since it includes the impact of uncertainty, as well as variability. The ratio of over generation in the RT-5 and RT-H simulation for May 28th is 2.2. While the RT-H identified days when uncertainty in load and wind generation is likely to result in operational problems, other methods were used to identify interesting days when the intra-hour ramps might exacerbate these problems. The next section discusses this methodology.

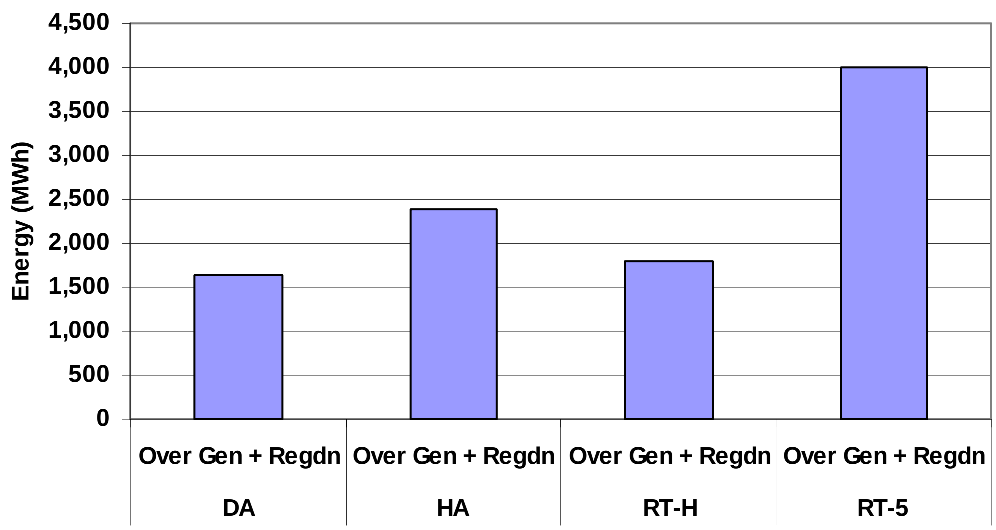


Figure C-3: Over generation for May 28th in RT-H and RT-5 Simulations.

Table C-1: Daily operating issues for May.

Date	DA Over Gen	HA Over Gen	RT-H Over Gen	DA Regdn	HA Regdn	RT-H Regdn	DA Over Gen + Regdn	HA Over Gen + Regdn	RT-H Over Gen + Regdn
5/1/2012	0.0	0.0	0.0	0.5	0.0	0.0	0.5	0.0	0.0
5/2/2012	1.0	0.0	0.0	1.7	1.9	0.0	2.7	1.9	0.0
5/3/2012	0.0	5.0	0.0	1.8	6.2	0.0	1.8	11.2	0.0
5/4/2012	67.8	86.5	15.2	73.2	110.7	48.4	141.0	197.2	63.7
5/5/2012	85.8	62.3	10.1	58.2	71.4	45.7	144.0	133.6	55.8
5/6/2012	5.9	2.5	1.0	18.7	11.2	8.7	24.6	13.7	9.7
5/7/2012	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0
5/8/2012	0.0	0.0	0.0	0.0	0.3	0.0	0.0	0.3	0.0
5/9/2012	167.4	292.3	247.8	92.2	110.0	132.6	259.6	402.4	380.4
5/10/2012	41.6	106.9	54.0	12.6	23.3	15.2	54.2	130.2	69.2
5/11/2012	1.2	78.6	11.4	3.8	24.1	8.0	5.0	102.8	19.4
5/12/2012	6.1	4.4	0.0	5.3	3.2	0.0	11.5	7.7	0.0
5/13/2012	18.0	10.8	0.8	6.5	5.3	0.1	24.5	16.1	0.9
5/14/2012	4.3	13.3	4.4	2.2	3.6	1.5	6.5	16.9	5.9
5/15/2012	43.8	101.4	9.8	0.0	0.0	0.0	43.8	101.4	9.8
5/16/2012	2.6	12.8	0.0	0.0	0.0	0.0	2.6	12.8	0.0
5/17/2012	7.8	3.6	0.0	0.0	0.0	0.0	7.8	3.6	0.0
5/18/2012	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0
5/19/2012	26.6	25.7	3.0	6.7	0.0	0.0	33.3	25.7	3.0
5/20/2012	241.6	356.5	93.5	152.9	201.7	164.4	394.4	558.2	257.9
5/21/2012	349.6	269.5	121.5	1.2	1.1	0.0	350.9	270.7	121.5
5/22/2012	348.2	364.4	257.8	0.0	0.0	0.0	348.2	364.4	257.8
5/23/2012	19.5	136.1	42.7	0.0	0.0	0.0	19.5	136.1	42.7
5/24/2012	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0
5/25/2012	0.0	6.0	0.0	0.0	0.0	0.0	0.0	6.0	0.0
5/26/2012	19.2	27.7	1.9	36.7	53.1	31.6	56.0	80.9	33.6
5/27/2012	1,058.1	802.9	331.5	347.7	375.3	330.5	1,405.9	1,178.2	662.0
5/28/2012	1,140.7	1,622.0	780.3	489.8	756.9	1,021.6	1,630.5	2,378.9	1,801.9
5/29/2012	166.4	203.8	133.1	0.0	0.0	0.0	166.4	203.8	133.1
5/30/2012	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0
5/31/2012	0.4	0.0	0.0	0.0	0.0	0.0	0.4	0.0	0.0
Total	3,823.8	4,595.2	2,119.8	1,311.9	1,759.4	1,808.4	5,135.7	6,354.6	3,928.1

C.3 Further Analysis for Interesting Days

A combination of statistical data analysis, generation schedules, and results from Plexos deterministic and stochastic simulations was used to find “interesting” periods during the year for more extensive analysis. These periods included

- Days when real-time net load ramp up and down events far exceeded the average hourly scheduled (forecasted) ramp
- Days when real-time net load ramp up and down events are a high percentage of the hourly flexible generation
- Days with low amounts of dispatchable generation
- Days with Dump Energy in the stochastic hourly simulations
- Days with regulation and spin shortfalls in the hourly stochastic simulation

A number of days meeting each criterion above were selected on their merits, then they were collectively ranked and prioritized to determine a subset of days for in-depth analysis.

C.4 Five-Minute Ramp Ratios

The five-minute load, wind, solar and net load ramps were analyzed to find periods during the year when maximum five-minute net load ramp in an hour was much greater than the average scheduled ramp during the hour. The general procedure was

1. create 5-minute deltas (difference between successive 5-minute periods)
2. calculate maximum positive delta and maximum negative delta in each hour
3. calculate the average delta in each hour
4. compute ratio maximum delta/average delta for each hour

The concern is that the commitment is based on the hourly loads and therefore only consider the hourly load deltas and by extension, only the average 5-minute deltas within the hour. If a particular 5-minute delta is 10 or 20 times the average for the hour then there might not be enough ramping capability available and ramp violations could occur.

C.4.1 Load and Net Load Deltas

Figure C-4 shows the distribution of load and net load maximum 5-minute deltas in each hour of the 2006 shape year. The magenta bars show the number of positive and negative load deltas in each bin, and the blue bars show the number of positive and negative net load deltas in each bin. Net Load is defined as Load – Wind – Solar generation. As expected, each half of the distribution of deltas is skewed, but more so for load than net load.

For the positive deltas (or up-ramps), 80% of the load deltas are in the first 4 bins (200 MW or less) whereas only 68% of the net load deltas are 200 MW or less. On the tails of the distribution, there are 35 hours with a five-minute load delta of 600 MW or more, and 68 hours with a net load delta of 600 MW. However, the largest load up-ramp, 5,637 MW, is about the same as the largest net load up-ramp 5,634 MW.

The difference between load and net load is less distinct for the down-ramps. Approximately 77% of load deltas are 200 MW or less, and about 74% of net load deltas are in the same range. On the tail end, 11 load down-ramps are greater than or equal to 600 MW, compared to 19 net load down-ramps. Again, the largest load down-ramp, 5,808 MW, is about the same as the largest net load down-ramp.

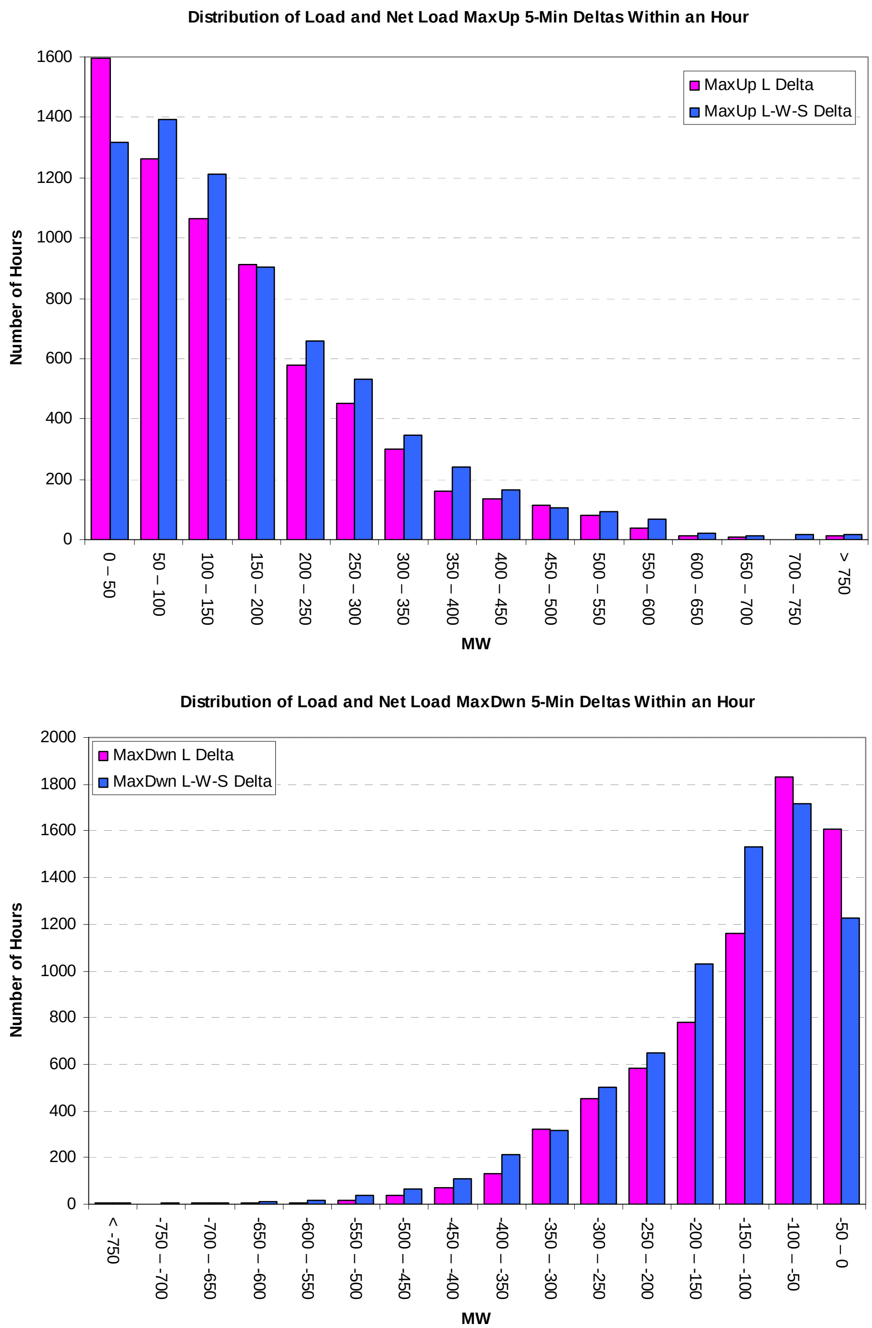
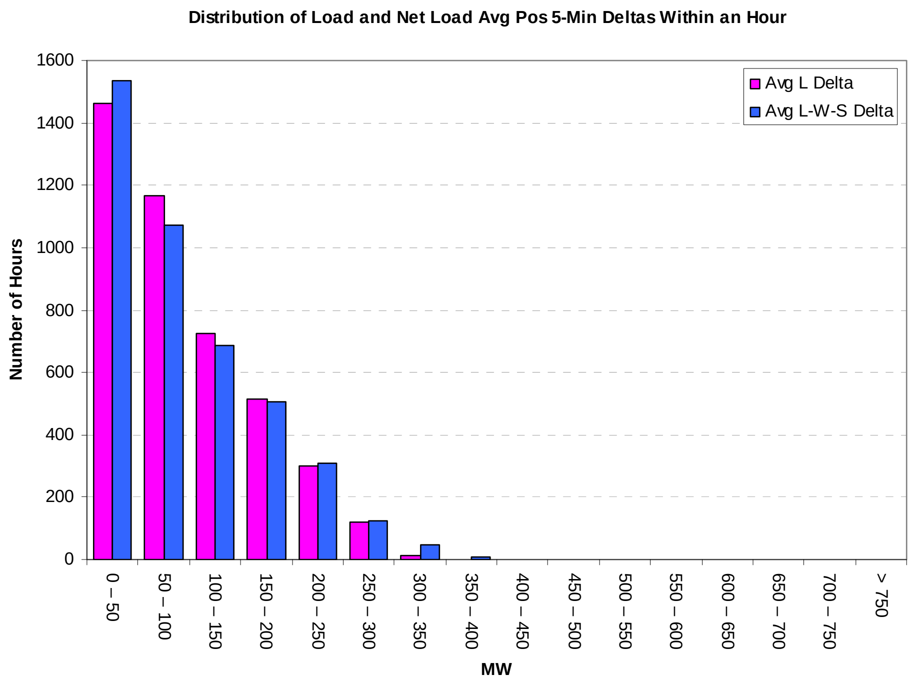


Figure C-4: Distribution of maximum 5-minute load and net load deltas in each hour

These 5-minute deltas are compared to the average 5-minute deltas within the hour to identify periods where the real-time ramping requirement outpaces the scheduled hourly ramp. Figure C-5 shows the distribution of average 5-minute ramps for load and net load in the 2006 shape year. The top plot shows the distribution of positive load and net load average 5-minute deltas, and the bottom plot shows the distribution of negative load and net load average 5-minute deltas. On both plots there are more hours with large average

5-minute deltas (on the tails of the distributions) with wind and solar than with load alone, although the difference may not be as great as expected.



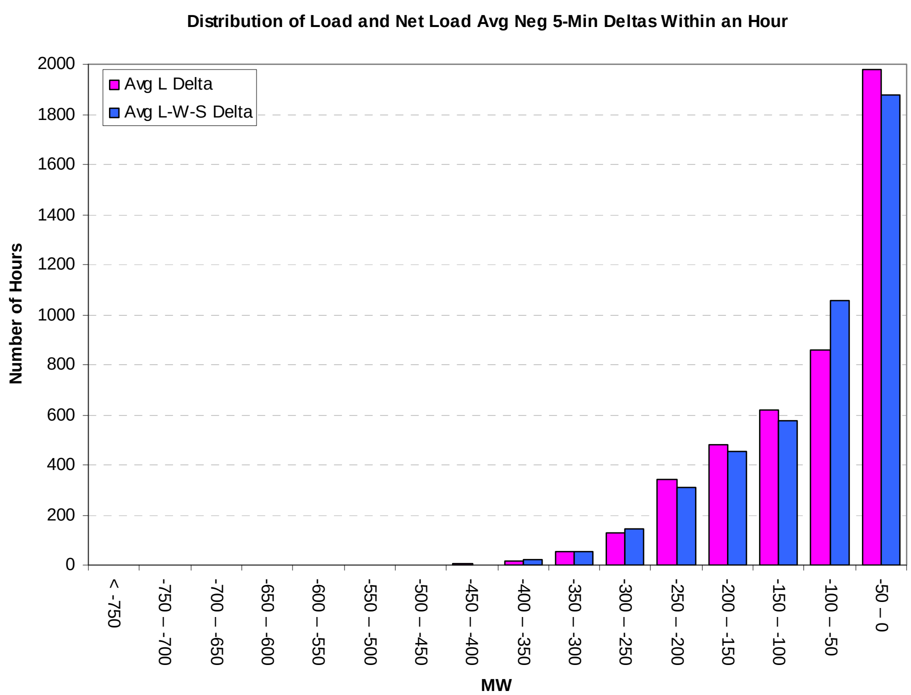


Figure C-5: Distribution of average hourly load and net load deltas

C.4.2 Max/Average Ratios

The maximum five-minute deltas and average five-minute deltas discussed above were used to compute the ratios. The simple relation is:

$$\text{Ratio} = \frac{\text{Maximum Five-Minute Ramp}}{\text{Average Five-Minute Ramp}}$$

Large ratios that are due to a small average hourly ramp (in the numerator) are not particularly interesting. Therefore a threshold was used to screen out these hours. Figure C-6 below (a scatter plot of maximum positive deltas versus average hourly deltas) shows how this threshold was determined. In the figure, magenta triangles represent a load hours and blue diamonds represent net load hours.

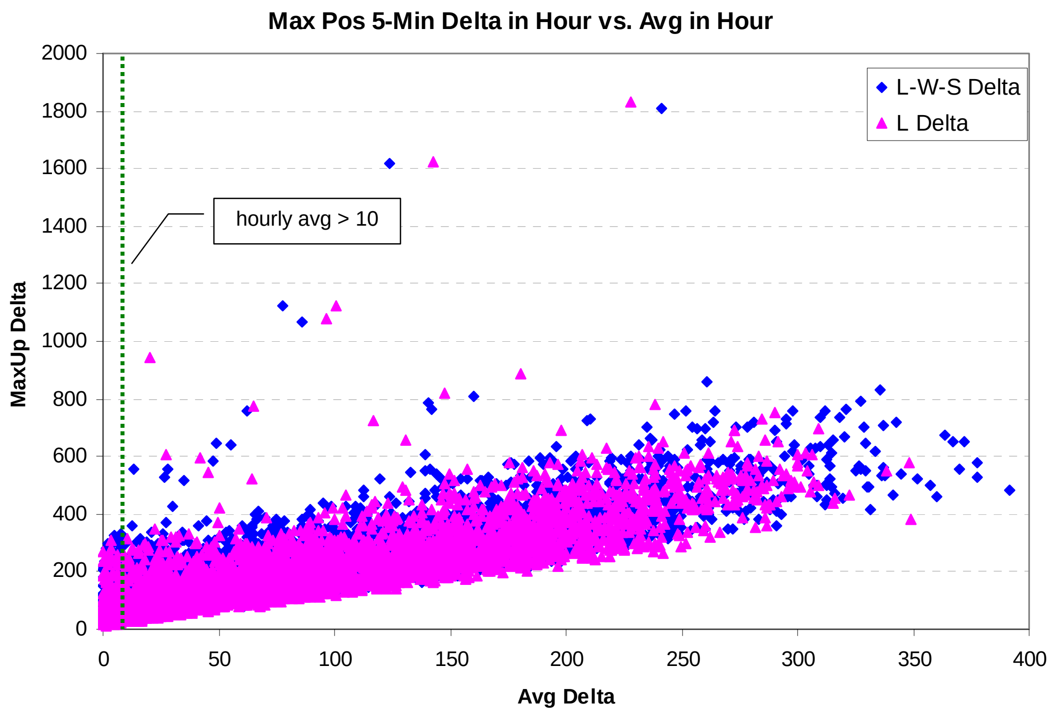


Figure C-6: Scatter plot of maximum positive deltas versus average delta in each hour

All the hours with a large maximum five-minute delta fall to the right of the vertical line at Avg Delta = 10. Therefore an initial threshold of Avg Delta > 10 was used to screen out large ratios caused by small averages. A similar threshold was used to initially screen the down-ramp ratios. Subsequently, an exercise was carried to determine if the initial threshold should be increased from 10, i.e. whether a threshold of 20 or 30 would be more selective.

Figure 7 shows the MaxUp/Avg ratios for Avg Delta >10, Avg Delta >20, and Avg Delta >30 over the year. Blue diamonds represent ratios where Avg Delta >10, magenta squares represent ratios where Avg Delta >20, and green triangles represent ratios where Avg Delta > 30. The superposition of ratios selected using these three screening values confirm that there is no advantage in filtering with a threshold greater than 10.

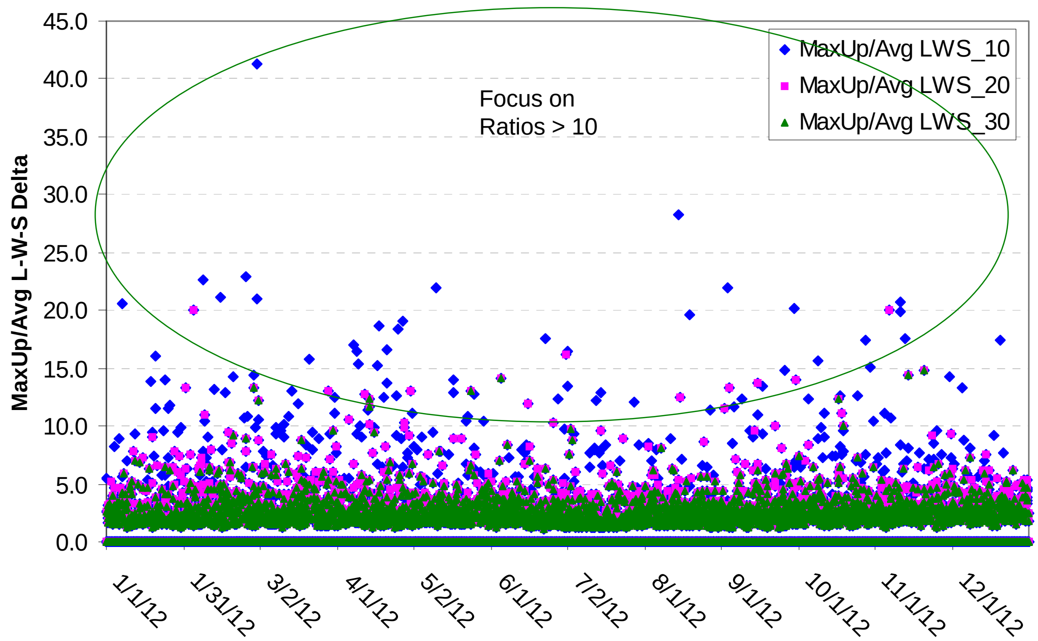


Figure C-7: MaxUp/Avg ratios for Avg Delta >10, Avg Delta >20, and Avg Delta >30

Figure C-8 shows a scatter plot of the up-ramp ratios versus the average hourly delta. As before, magenta triangles represent a load hours and blue diamonds represent net load hours. As expected, there are many large ratios clustered vertically on the left side where the average hourly delta is low.

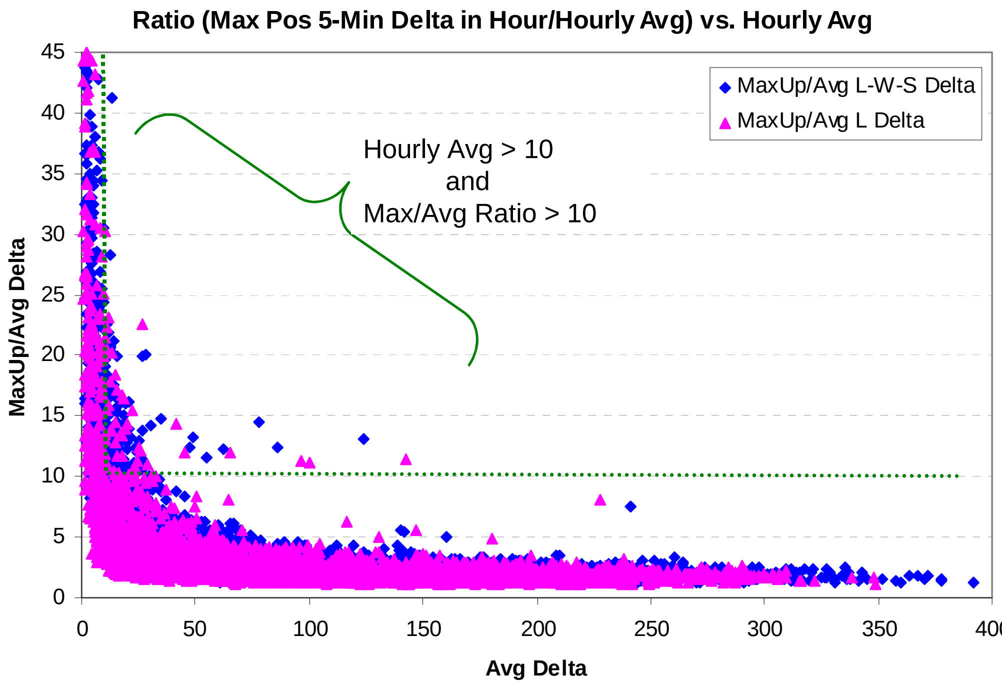


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Figure C-8: Scatter plot of MaxUp/Avg ratio versus average delta in each hour

However, the largest ratio with Avg Delta > 10 is at 41.2. In general, the set of hours with Max/Avg ratio > 10 and Avg Delta >10, (i.e. to the left of the vertical green line and above the horizontal green line) are the hours of interest from this exercise. These hours are listed in Table C-2. The hours of interest for down-ramps were determined in a similar manner and are listed in Table C-3.

Table C-2: Periods of Interest Based on MaxUp/Average Ratios

Date	Ratio	Date	Ratio	Date	Ratio	Date	Ratio	Date	Ratio	Date	Ratio
2/29/12 15:00	41.2	10/28/12 2:00	17.4	5/17/12 14:00	14.0	4/12/12 7:00	12.8	9/5/12 18:00	11.6	5/29/12 18:00	10.5
8/14/12 19:00	28.3	12/20/12 8:00	17.4	1/24/12 8:00	14.0	5/26/12 4:00	12.8	1/20/12 10:00	11.5	2/8/12 18:00	10.5
2/25/12 8:00	22.9	4/8/12 7:00	17.0	9/30/12 18:00	13.9	10/18/12 7:00	12.6	9/2/12 5:00	11.5	10/31/12 13:00	10.4
2/8/12 2:00	22.6	4/21/12 2:00	16.5	1/18/12 8:00	13.9	10/25/12 2:00	12.6	1/25/12 8:00	11.5	5/22/12 17:00	10.4
5/10/12 19:00	21.9	4/9/12 7:00	16.5	9/15/12 3:00	13.8	4/25/12 9:00	12.6	4/13/12 16:00	11.4	6/26/12 2:00	10.4
9/3/12 5:00	21.9	7/2/12 2:00	16.5	4/21/12 1:00	13.7	3/31/12 7:00	12.5	8/27/12 18:00	11.4	4/28/12 7:00	10.3
2/15/12 2:00	21.1	7/1/12 3:00	16.2	9/17/12 13:00	13.5	4/20/12 3:00	12.5	10/19/12 1:00	11.2	4/14/12 5:00	10.2
3/1/12 1:00	21.0	1/20/12 8:00	16.1	7/1/12 19:00	13.4	8/15/12 19:00	12.4	11/4/12 14:00	11.1	3/11/12 3:00	10.1
11/11/12 4:00	20.7	3/21/12 7:00	15.7	12/5/12 8:00	13.4	4/14/12 8:00	12.4	10/11/12 16:00	11.1	10/19/12 6:00	10.1
1/7/12 3:00	20.6	10/9/12 12:00	15.6	2/1/12 13:00	13.4	10/5/12 16:00	12.4	5/1/12 11:00	11.1	9/22/12 7:00	10.0
9/29/12 18:00	20.2	4/9/12 16:00	15.3	9/4/12 2:00	13.3	10/17/12 10:00	12.4	3/31/12 10:00	11.1	4/10/12 9:00	10.0
2/4/12 18:00	20.1	4/17/12 7:00	15.2	2/28/12 8:00	13.2	9/9/12 7:00	12.3	9/15/12 11:00	11.0		
11/6/12 12:00	20.0	10/30/12 2:00	15.1	2/12/12 13:00	13.2	6/28/12 2:00	12.3	2/9/12 2:00	10.9		
11/11/12 3:00	19.9	9/26/12 7:00	14.9	5/24/12 11:00	13.1	3/1/12 8:00	12.2	5/23/12 14:00	10.9		
8/19/12 5:00	19.6	11/20/12 10:00	14.8	4/30/12 19:00	13.1	7/13/12 2:00	12.2	3/13/12 8:00	10.8		
4/27/12 19:00	19.1	2/28/12 7:00	14.5	3/14/12 16:00	13.0	7/28/12 4:00	12.0	2/26/12 6:00	10.8		
4/18/12 10:00	18.7	11/14/12 7:00	14.4	3/29/12 2:00	13.0	3/17/12 7:00	12.0	2/24/12 16:00	10.7		
4/25/12 16:00	18.4	11/30/12 15:00	14.3	5/17/12 18:00	12.9	6/16/12 3:00	12.0	11/7/12 12:00	10.7		
11/13/12 3:00	17.6	2/20/12 8:00	14.3	2/17/12 2:00	12.9	1/26/12 10:00	11.7	3/1/12 9:00	10.6		
6/23/12 4:00	17.5	6/5/12 12:00	14.2	7/15/12 3:00	12.9	4/14/12 9:00	11.6	4/6/12 7:00	10.6		

Table C-3: Periods of Interest Based on MaxDown/Average Ratios

Date	Ratio	Date	Ratio	Date	Ratio	Date	Ratio
10/27/12 0:00	69.5	8/6/12 18:00	15.1	10/30/12 15:00	11.9	4/4/12 15:00	10.4
5/3/12 17:00	30.6	5/24/12 10:00	14.8	7/30/12 18:00	11.9	12/9/12 3:00	10.4
5/7/12 10:00	24.4	10/11/12 10:00	14.7	2/7/12 14:00	11.7	2/7/12 12:00	10.3
5/2/12 11:00	19.3	1/23/12 14:00	14.7	5/26/12 0:00	11.7	10/13/12 10:00	10.3
1/12/12 12:00	19.2	1/4/12 11:00	14.4	1/3/12 12:00	11.7	11/9/12 3:00	10.3
12/2/12 6:00	18.2	2/3/12 10:00	14.1	5/9/12 14:00	11.6	6/2/12 18:00	10.3
7/25/12 19:00	18.1	5/2/12 10:00	14.0	7/2/12 14:00	11.3	2/26/12 19:00	10.3
3/16/12 3:00	17.9	3/25/12 14:00	13.8	3/1/12 15:00	11.0	11/15/12 15:00	10.3
3/24/12 15:00	17.3	1/22/12 6:00	13.8	8/31/12 14:00	11.0	3/7/12 9:00	10.2
10/22/12 2:00	17.0	1/4/12 18:00	13.6	4/6/12 1:00	10.8	12/17/12 15:00	10.2
4/15/12 5:00	16.9	2/26/12 8:00	13.2	6/30/12 4:00	10.8	7/14/12 15:00	10.2
3/11/12 4:00	16.8	6/18/12 14:00	13.2	9/13/12 11:00	10.7	4/26/12 19:00	10.2
7/17/12 2:00	16.7	3/11/12 6:00	13.2	10/25/12 11:00	10.7	5/19/12 14:00	10.1
10/28/12 6:00	16.6	11/14/12 12:00	13.1	8/10/12 19:00	10.6	4/8/12 0:00	10.1
7/25/12 14:00	16.4	12/11/12 14:00	12.4	1/20/12 15:00	10.6	2/24/12 8:00	10.1
5/13/12 16:00	16.0	11/20/12 18:00	12.3	5/20/12 4:00	10.6	9/21/12 16:00	10.0
4/25/12 19:00	15.5	5/1/12 14:00	12.2	11/9/12 12:00	10.6		
5/2/12 16:00	15.4	8/26/12 4:00	12.1	4/2/12 16:00	10.6		
4/24/12 16:00	15.3	12/11/12 15:00	12.0	10/3/12 18:00	10.5		
4/24/12 19:00	15.3	7/6/12 2:00	11.9	10/7/12 15:00	10.4		

C.5 Flexible generation Ratios

The other aspect that was considered was the amount of dispatchable generation available within the hour. An hour with a relatively small ramp but with little dispatchable generation may cause more difficulty that an hour with large ramps and lots of dispatchable generation. The analysis started with the 2012 deterministic dispatch for the year based on the 2006 load profile. 50% of the imports were assumed to be fixed and the remainder dispatchable at $80/MWh. All of the Geothermal, Biomass, Nuclear, Qualifying Facilities (QF), Wind and Solar generation were assumed to be firm. Only the in-state gas fired generation was left dispatchable. Figure C-9 shows the results for the first week in May. Although the loads ranged from roughly 20,000 MW to 35,000 MW the amount of dispatchable generation, which is the difference between the load and total non-dispatchable generation, was very low at times.

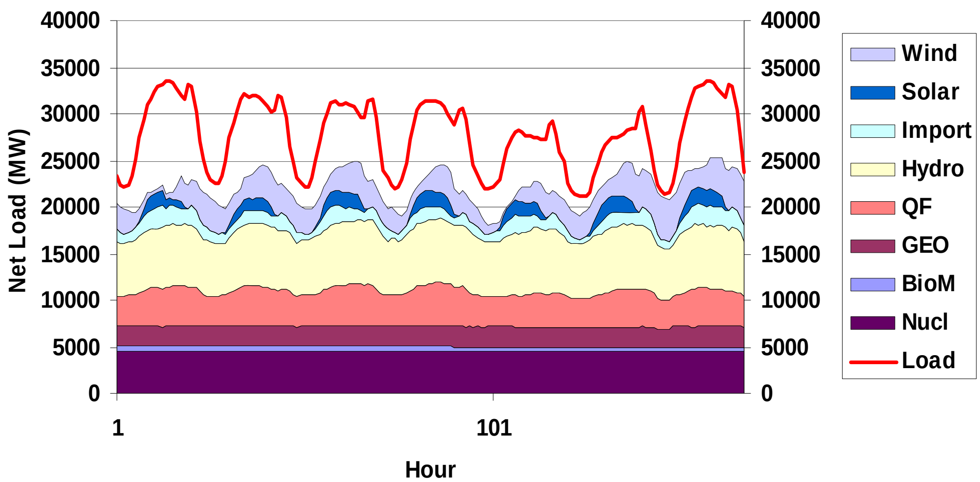


Figure C-9: Dispatch for the first week of May.

The analysis then examined each hour for "interesting" events. In addition to the hours identified previously when the maximum up and down ramps were greater than ten times the average ramp the amount of dispatchable generation was also considered. First, hours with less than 1500 MW of dispatchable generation were flagged. Then the maximum ramps were compared to the amount of dispatchable generation. Those hours when the maximum up or down 5-minute ramp exceed 15% of the dispatchable generation were identified. Table C-4 lists all of the events for the month of May. All of the evaluation criteria is shown with the items flagged highlighted in yellow. In some hours and days multiple events occurred.

Table C-4: Interesting events for May

Month	Day	Hour	MaxUp L-W-S Delta	MaxDwn L-W-S Delta	Dispatchable	Max Up / Disp	Max Dn / Disp	MaxUp/Avg LWS_10	MaxDwn/Avg LWS_10	Events
5	1	12	157.3	-89.1	10,610.9	1%	-1%	11.1		1
5	1	15	60.2	-138.4	11,494.0	1%	-1%		12.2	1
5	2	11	69.2	-213.9	9,958.6	1%	-2%		14.0	1
5	2	12	46.0	-201.9	10,135.3	0%	-2%		19.3	1
5	2	17	74.5	-204.1	8,970.0	1%	-2%		15.4	1
5	3	18	174.1	-390.3	6,207.1	3%	-6%		30.6	1
5	4	5	328.1	-17.6	2,072.8	16%	-1%	2.2		1
5	7	11	81.1	-251.2	9,680.0	1%	-3%		24.4	1
5	9	3	84.1	-72.7	1,087.3	8%	-7%			1
5	9	4	206.5	-29.3	920.0	22%	-3%	2.1		2
5	9	5	247.8	-4.3	1,441.3	17%	0%	2.0		2
5	9	6	397.6	116.5	2,572.0	15%	0%	1.9		1
5	9	15	113.8	-128.2	9,869.1	1%	-1%		11.6	1
5	10	20	253.6	-193.1	8,544.9	3%	-2%	21.9		1
5	13	17	61.6	-230.7	9,432.7	1%	-2%		16.0	1
5	17	15	141.5	-207.2	11,964.8	1%	-2%	14.0		1
5	17	19	206.4	-145.6	11,001.9	2%	-1%	12.9		1
5	19	15	60.2	-132.4	5,849.4	1%	-2%		10.1	1
5	20	4	33.4	-75.1	1,389.5	2%	-5%		3.4	1
5	20	5	95.3	-142.4	1,268.0	8%	-11%		10.6	2
5	20	7	160.7	-33.3	903.0	18%	-4%	2.7		2
5	20	8	222.6	105.1	1,021.0	22%	0%	1.5		2
5	21	2	23.9	-66.1	1,241.0	2%	-5%		3.2	1
5	21	3	21.0	-27.6	1,084.0	2%	-3%			1
5	21	4	123.5	47.1	998.7	12%	0%	1.4		1
5	21	5	225.0	-121.1	1,328.2	17%	-9%	1.9		2
5	22	2	-11.6	-104.4	883.7	0%	-12%		2.6	1
5	22	3	56.7	-61.1	691.0	8%	-9%			1
5	22	4	127.7	45.9	928.1	14%	0%	1.5		1
5	22	5	273.1	3.1	1,165.0	23%	0%	2.1		2
5	22	6	340.7	115.3	2,293.8	15%	0%	1.7		1
5	22	18	164.3	-238.1	6,125.0	3%	-4%	10.4		1
5	23	15	133.4	-78.8	9,952.5	1%	-1%	10.9		1
5	24	11	58.4	-1,231.4	9,590.6	1%	-13%		14.8	1
5	24	12	1,618.8	-449.5	9,919.5	16%	-5%	13.1		2
5	26	1	198.1	-171.1	3,111.4	6%	-6%		11.7	1
5	26	5	168.8	-125.6	2,492.5	7%	-5%	12.8		1
5	27	2	3.6	-77.8	1,277.9	0%	-6%		2.1	1
5	27	3	36.3	-45.3	1,143.1	3%	-4%			1
5	27	4	107.4	-11.2	948.2	11%	-1%	5.1		1
5	27	5	105.6	-127.3	1,050.6	10%	-12%			1
5	27	6	168.7	2.2	1,399.1	12%	0%	3.6		1
5	27	7	202.4	-159.6	895.5	23%	-18%	3.6		3
5	27	8	293.8	-181.4	969.1	30%	-19%	3.3		3
5	27	9	310.3	39.2	1,263.9	25%	0%	2.4		2
5	28	2	-12.9	-76.6	1,397.0	0%	-5%		1.8	1
5	28	3	17.6	-34.3	1,123.5	2%	-3%			1
5	28	4	65.7	1.6	1,165.2	6%	0%	2.6		1
5	28	5	135.6	-126.7	1,324.0	10%	-10%			1
5	28	6	128.9	-1.7	1,450.5	9%	0%	3.3		1
5	28	7	129.3	-9.7	914.7	14%	-1%	1.8		1
5	28	8	214.0	-199.4	692.1	31%	-29%	4.0		3
5	28	9	221.0	71.2	774.2	29%	0%	1.6		2
5	28	10	123.3	4.3	1,061.6	12%	0%	1.7		1
5	28	15	47.7	-126.2	1,414.4	3%	-9%			1
5	28	16	69.7	-28.3	1,205.6	6%	-2%	3.1		1
5	29	1	61.0	-93.8	1,340.3	5%	-7%		2.5	1
5	29	2	73.0	-104.4	1,269.5	6%	-8%		6.9	1
5	29	19	184.8	-58.9	8,122.9	2%	-1%	10.5		1

Figure C-10 shows the total number of interesting events by month. This analysis, along with the previous hourly stochastic dispatch analysis for the year, confirmed that the month of May would be the most difficult from an operational standpoint. Another summary of the statistics is shown in Table C-5.

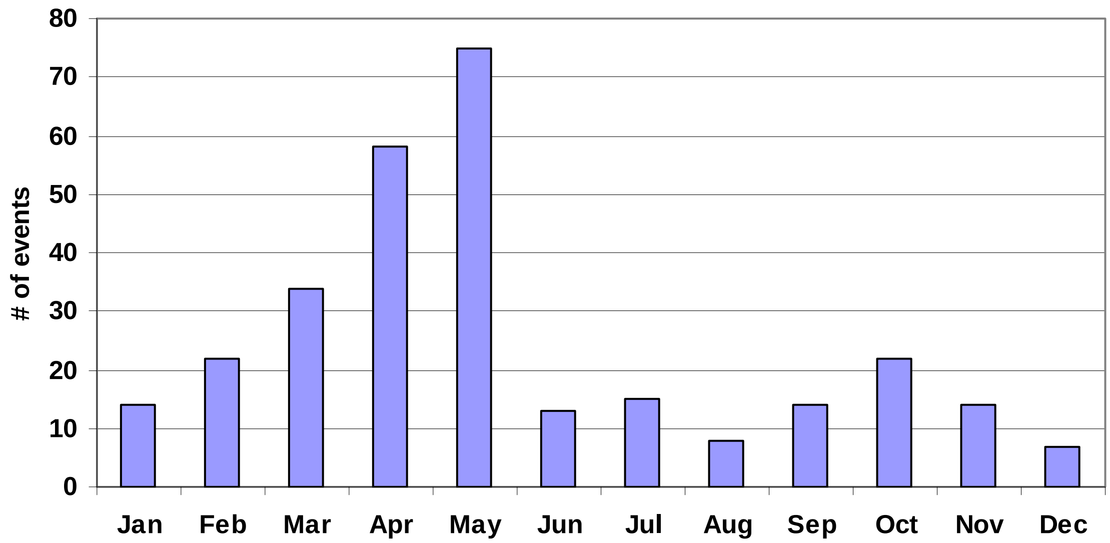


Figure C-10: Number of "interesting" event by month

Table C-5: Statistics of interesting events, 2006

Event	Count
1) Dispatchable Generation < 1500 MW	61
2) Max Up / Dispatchable > 15%	37
3) Max Down / Dispatchable > 15%	11
4) Max Up Ramp / Avg Ramp > 10	111
5) Max Down Ramp / Avg Ramp > 10	76
total events	296
Unique hours	263
Unique days	152
Days > 2 events	28

Table C-6 shows the days with more than two events happening at some time within the day. From this analysis, and based on statistics from the hourly stochastic dispatches, the days of May 16, 17, 24, 27 and 28 were selected for further sub-hourly analysis.

Table C-6: Summary of days with more than two events.

Month	Day	Events
1	20	3
2	26	3
3	1	4
3	11	3
3	25	12
3	26	4
4	6	4
4	8	3
4	9	3
4	14	7
4	15	10
4	17	4
4	19	3
4	21	5
4	25	3
4	27	3
5	2	3
5	9	7
5	20	7
5	21	5
5	22	7
5	24	3
5	27	13
5	28	14
5	29	3
6	11	3
7	2	4
10	27	3

C.6 2007 Analysis

The bulk of the analysis was performed on the 2006 load and generation shape data which had a high amount of hydro generation. The year 2007, which had significantly less hydro generation, was also analyzed. Figure C-11 shows a comparison of the generation by type for the two shape years considered. The hydro generation in 2007 is only slightly more than half of the 2006 level. The bulk of the difference is made up by increased imports and in-state gas fired generation.

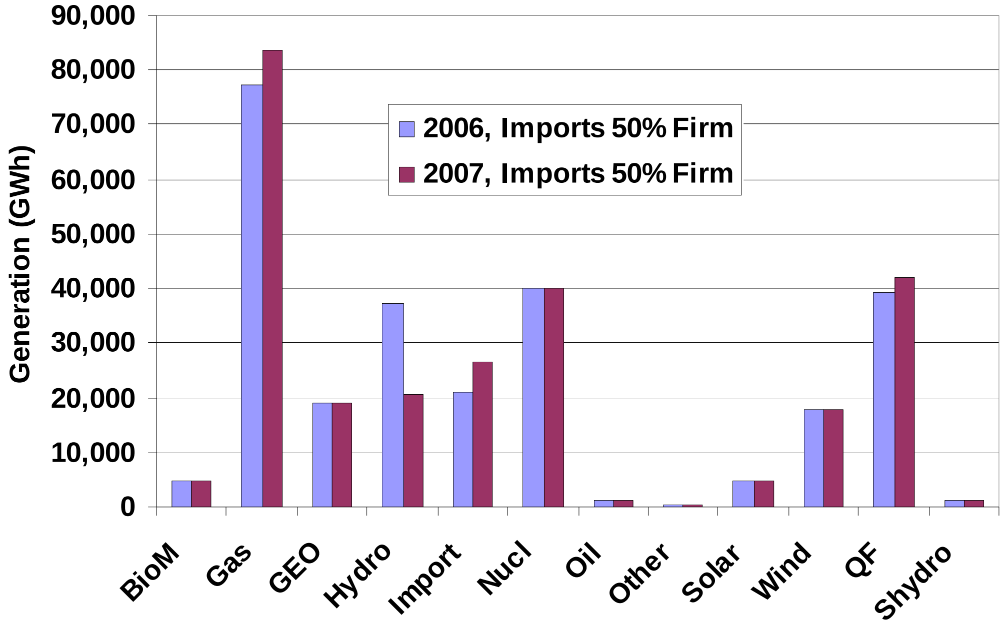


Figure C-11: Comparison of generation by type for 2006 and 2007

Table C-7 Compares the amount of firm generation available each hour for the 2006 and 2007 based simulations. Because of the reduced hydro generation there is more flexible generation available to operate each hour.

Table C-7: Comparison of generation by type for 2006 and 2007

Gentyp	2006, Imports 50% Firm	2007, Imports 50% Firm
BioM	4,692	4,692
Gas	77,486	83,677
GEO	19,019	19,017
Hydro	37,240	20,662
Import	20,858	26,638
Nucl	39,967	39,967
Oil	1,010	1,010
Other	226	227
Solar	4,907	4,907
Wind	17,886	17,886
QF	39,206	42,129
Shydro	1,047	1,047
Total	263,543	261,858
Renewable	47,550	47,547
Renewable	18%	18%

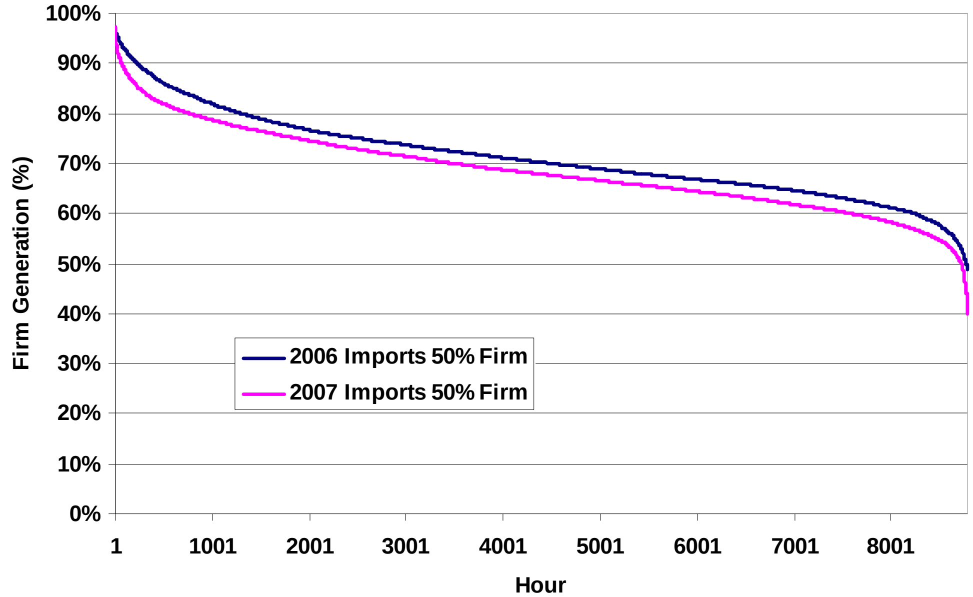


Figure C-12: Comparison of firm generation for 2006 and 2007

The operating issues (high ramping, low flexibility, etc) were also evaluated for the 2007 shapes. Figure C-13 shows the number of issues occurring each month. Similar to what was seen in the 2006 analysis, May seemed to be the worst month. Figure C-13 shows the number and type of issues for each day in May. Based on these results May 22nd and 23rd were studied at the 5-minute level.

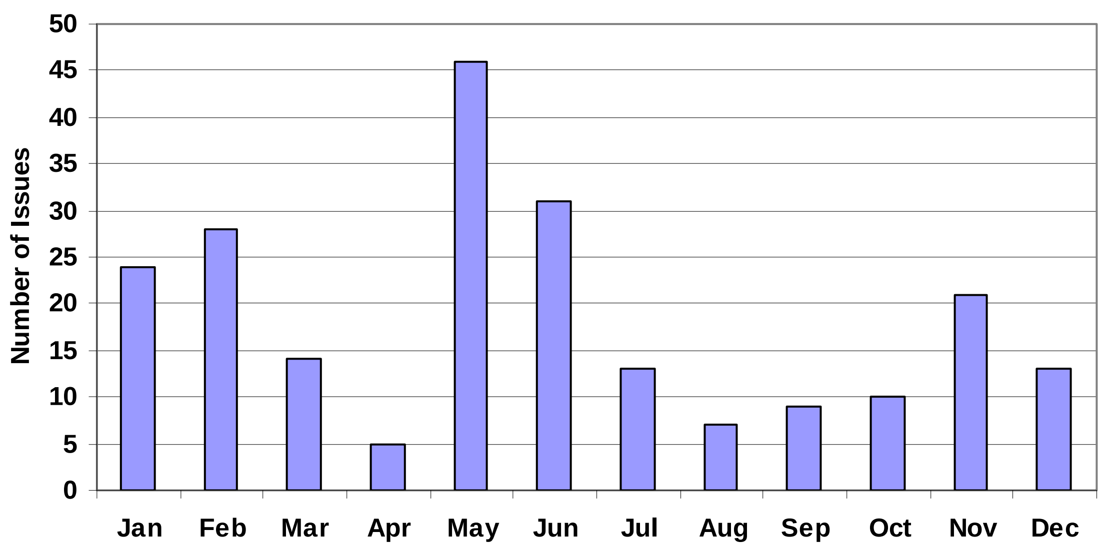


Figure C-13: Number of Operating issues in 2007

Table C-8: Daily Operating Issues in May 2007

Month	Day	Sum of Events	Max of MaxUp/Avg LW_10	Min of MaxDwn/ Avg LW_10	Max of Max Up L-W / Flexible Gen	Min of Max Dn L-W / Flexible Gen	Min of % Dispatchable Gen
5	1	1		10.9	1%	-4%	28%
5	3	2		10.6	3%	-3%	22%
5	4	1		17.1	2%	-3%	23%
5	8	3	5.9	1.6	2%	-5%	8%
5	9	1		23.4	3%	1%	28%
5	12	1		10.8	7%	-3%	25%
5	15	5	21.2	1.5	14%	-7%	9%
5	16	1	16.4		0%	-1%	28%
5	18	1		10.3	7%	1%	21%
5	19	1		11.8	7%	0%	21%
5	21	1		11.2	1%	-2%	19%
5	22	17	4.5	1.9	23%	-11%	6%
5	23	7	4.0	2.4	16%	-14%	7%
5	25	1		10.3	4%	-2%	20%
5	27	2		19.1	5%	0%	28%
5	31	1	10.0		1%	-1%	29%

C.7 Analysis of Operational capability under 20% RPS – Additional results

Sub-hourly analysis was conducted for five separate days within the month of May. Those days were the 16th, 17th, 24th, 27th and 28th. In addition to the 5-minute analysis a 10-minute analysis was done for the 24th and 28th for comparison purposes. Table C-9 shows the results from the DA, HA and RT-H analysis for comparison. The overall conclusion appears to be that if the hourly level simulations say that there is no operational issues, or only relatively small issues, then the sub-hourly analysis shows that the issues tend to go away. However, if the hourly level indicates that there may be a more significant issue then the sub-hourly simulation shows an even larger impact. Figures C-14 through Figure C-18 show the results graphically for the individual days where sub-hourly analysis was performed. Figure C-19 and Figure C-20 show similar results for May 22nd and 23rd from the 2007 analysis.

Table C-9: Comparative operational results for May

	DA	HA	RT-H	RT-5	DA	HA	RT-H	RT-5	DA	HA	RT-H	RT-5	DA	HA	RT-H	RT-5	DA	HA	RT-H	RT-5
Date	Dump	Dump	Dump	Dump	Regdn	Regdn	Regdn	Regdn	Regup	Regup	Regup	Regup	Spin	Spin	Spin	Spin	Dump+ Regdn	Dump+ Regdn	Dump+ Regdn	Dump+ Regdn
5/1/2012	0.0	0.0	0.0		0.5	0.0	0.0		0.0	0.0	0.0		0.0	0.0	0.0		0.5	0.0	0.0	0.0
5/2/2012	1.0	0.0	0.0		1.7	1.9	0.0		0.0	0.0	0.0		0.0	0.0	0.0		2.7	1.9	0.0	0.0
5/3/2012	0.0	5.0	0.0		1.8	6.2	0.0		0.0	0.0	0.0		0.7	0.0	0.0		1.8	11.2	0.0	0.0
5/4/2012	67.8	86.5	15.2		73.2	110.7	48.4		0.4	0.0	0.0		0.9	0.0	0.0		141.0	197.2	63.7	0.0
5/5/2012	85.8	62.3	10.1		58.2	71.4	45.7		0.0	0.0	0.0		1.1	0.0	0.0		144.0	133.6	55.8	0.0
5/6/2012	5.9	2.5	1.0		18.7	11.2	8.7		0.0	0.0	0.0		0.0	0.0	0.0		24.6	13.7	9.7	0.0
5/7/2012	0.0	0.0	0.0		0.0	0.0	0.0		0.0	0.0	0.0		0.0	0.0	0.0		0.0	0.0	0.0	0.0
5/8/2012	0.0	0.0	0.0		0.0	0.3	0.0		2.8	0.0	0.0		1.6	0.0	0.0		0.0	0.3	0.0	0.0
5/9/2012	167.4	292.3	247.8		92.2	110.0	132.6		0.0	0.0	0.0		9.9	0.2	0.0		259.6	402.4	380.4	0.0
5/10/2012	41.6	106.9	54.0		12.6	23.3	15.2		0.0	0.0	0.0		7.8	0.1	0.0		54.2	130.2	69.2	0.0
5/11/2012	1.2	78.6	11.4		3.8	24.1	8.0		0.0	0.0	0.0		2.1	0.0	0.0		5.0	102.8	19.4	0.0
5/12/2012	6.1	4.4	0.0		5.3	3.2	0.0		0.0	0.0	0.0		0.0	0.0	0.0		11.5	7.7	0.0	0.0
5/13/2012	18.0	10.8	0.8		6.5	5.3	0.1		0.0	0.0	0.0		0.7	0.1	0.0		24.5	16.1	0.9	0.0
5/14/2012	4.3	13.3	4.4		2.2	3.6	1.5		0.0	0.0	0.0		2.9	0.0	0.0		6.5	16.9	5.9	0.0
5/15/2012	43.8	101.4	9.8		0.0	0.0	0.0		0.0	0.0	0.0		5.5	0.6	0.0		43.8	101.4	9.8	0.0
5/16/2012	2.6	12.8	0.0	0.0	0.0	0.0	0.0	0.3	0.0	0.0	0.0	0.0	2.4	0.0	0.0	0.0	2.6	12.8	0.0	0.3
5/17/2012	7.8	3.6	0.0	0.2	0.0	0.0	0.0	0.1	0.0	0.0	0.0	1.2	0.1	0.0	0.0	0.0	7.8	3.6	0.0	0.3
5/18/2012	0.0	0.0	0.0		0.0	0.0	0.0		0.0	0.0	0.0		1.3	0.0	0.0		0.0	0.0	0.0	0.0
5/19/2012	26.6	25.7	3.0		6.7	0.0	0.0		0.0	0.0	0.0		9.2	0.2	0.0		33.3	25.7	3.0	0.0
5/20/2012	241.6	356.5	93.5		152.9	201.7	164.4		0.0	0.0	0.0		7.2	2.3	0.0		394.4	558.2	257.9	0.0
5/21/2012	349.6	269.5	121.5		1.2	1.1	0.0		0.0	0.0	0.0		4.4	0.6	0.0		350.9	270.7	121.5	0.0
5/22/2012	348.2	364.4	257.8		0.0	0.0	0.0		0.0	0.0	0.0		7.1	4.3	0.0		348.2	364.4	257.8	0.0
5/23/2012	19.5	136.1	42.7		0.0	0.0	0.0		0.2	0.0	0.0		6.3	0.2	0.0		19.5	136.1	42.7	0.0
5/24/2012	0.0	0.0	0.0	0.1	0.0	0.0	0.0	0.1	0.0	0.0	0.0	0.4	1.8	0.0	0.0	0.0	0.0	0.0	0.0	0.3
5/25/2012	0.0	6.0	0.0		0.0	0.0	0.0		0.0	0.0	0.0		4.0	0.0	0.0		0.0	6.0	0.0	0.0
5/26/2012	19.2	27.7	1.9		36.7	53.1	31.6		0.0	0.0	0.0		1.3	0.0	0.0		56.0	80.9	33.6	0.0
5/27/2012	1,058.1	802.9	331.5	1,485.7	347.7	375.3	330.5	955.7	2.3	0.0	0.0	1,150.4	8.1	5.2	0.0	168.7	1405.9	1178.2	662.0	2441.4
5/28/2012	1,140.7	1,622.0	780.3	2,561.3	489.8	756.9	1,021.6	1,435.4	1.2	0.0	0.0	1,099.0	22.4	10.1	0.3	311.3	1630.5	2378.9	1801.9	3996.7
5/29/2012	166.4	203.8	133.1		0.0	0.0	0.0		0.0	0.0	0.0		1.6	1.3	0.0		166.4	203.8	133.1	0.0
5/30/2012	0.0	0.0	0.0		0.0	0.0	0.0		0.0	0.0	0.0		0.0	0.0	0.0		0.0	0.0	0.0	0.0
5/31/2012	0.4	0.0	0.0		0.0	0.0	0.0		0.0	0.0	0.0		0.0	0.0	0.0		0.4	0.0	0.0	0.0
Total	3,823.8	4,595.2	2,119.8		1,311.9	1,759.4	1,808.4		7.0	0.0	0.0		110.3	25.3	0.3		5135.7	6354.6	3928.1	0.0

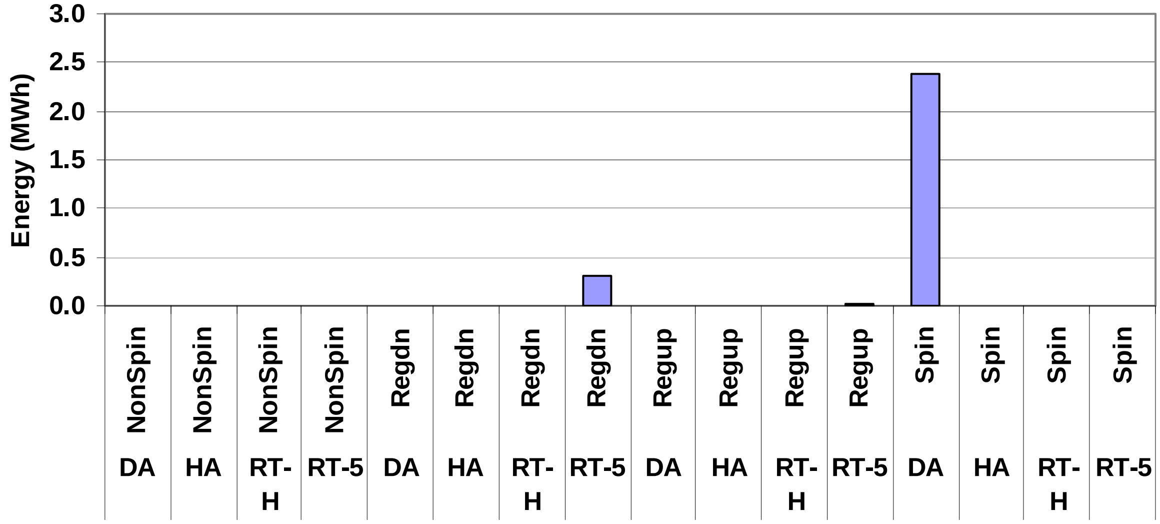


Figure C-14: May 16th Operational Issues based on 2006 Load Shapes

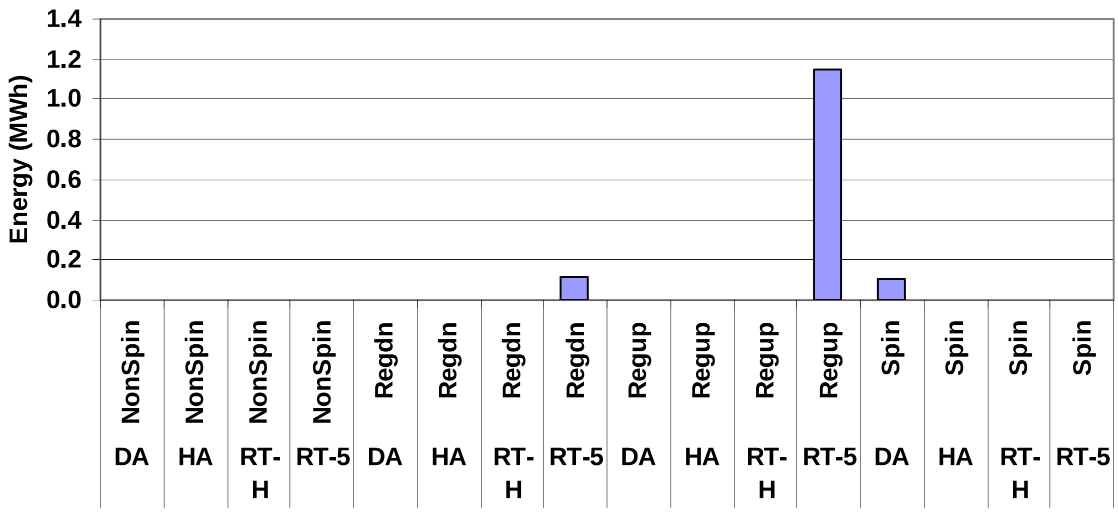


Figure C-15: May 17th Operational Issues based on 2006 Load Shapes

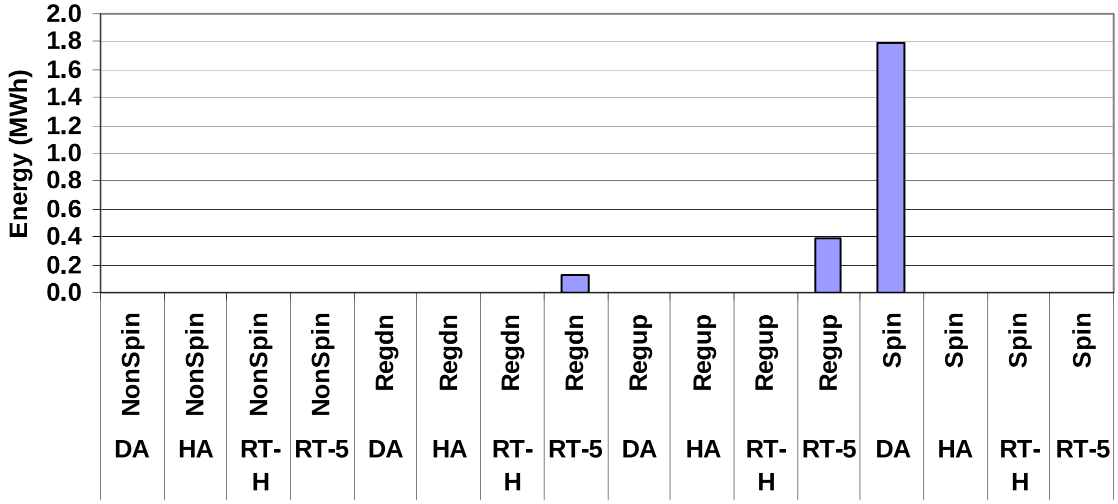


Figure C-16: May 24th Operational Issues based on 2006 Load Shapes

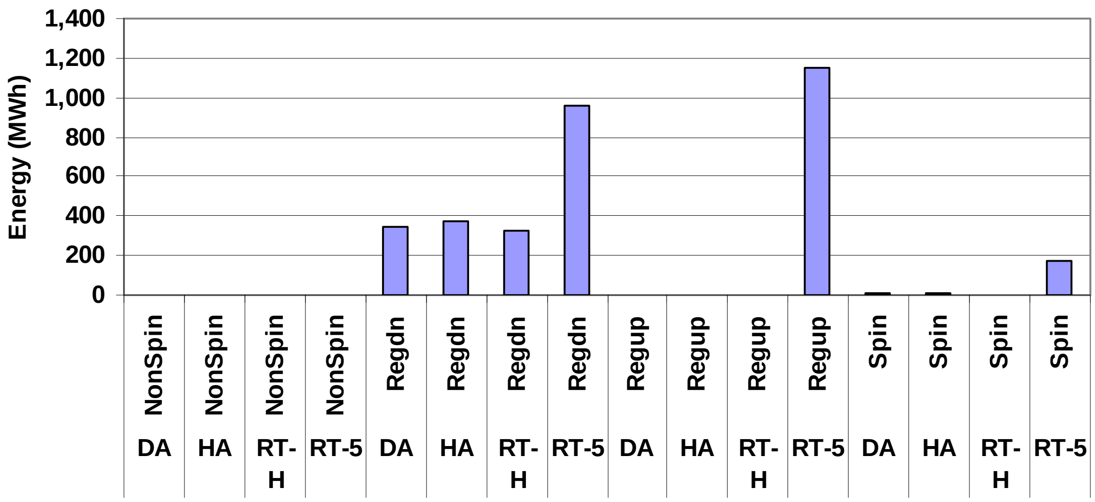


Figure C-17: May 27th Operational Issues based on 2006 Load Shapes

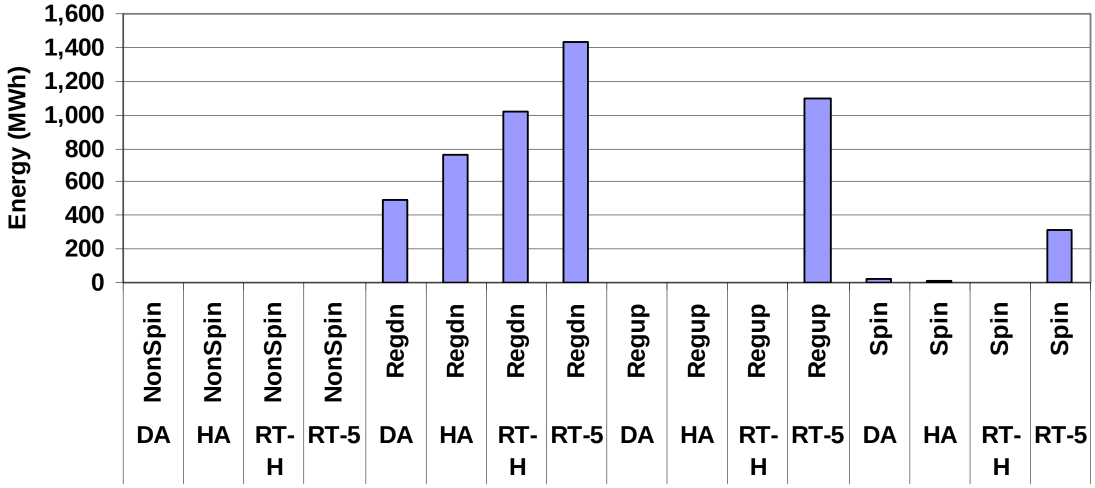


Figure C-18: May 28th Operational Issues based on 2006 Load Shapes

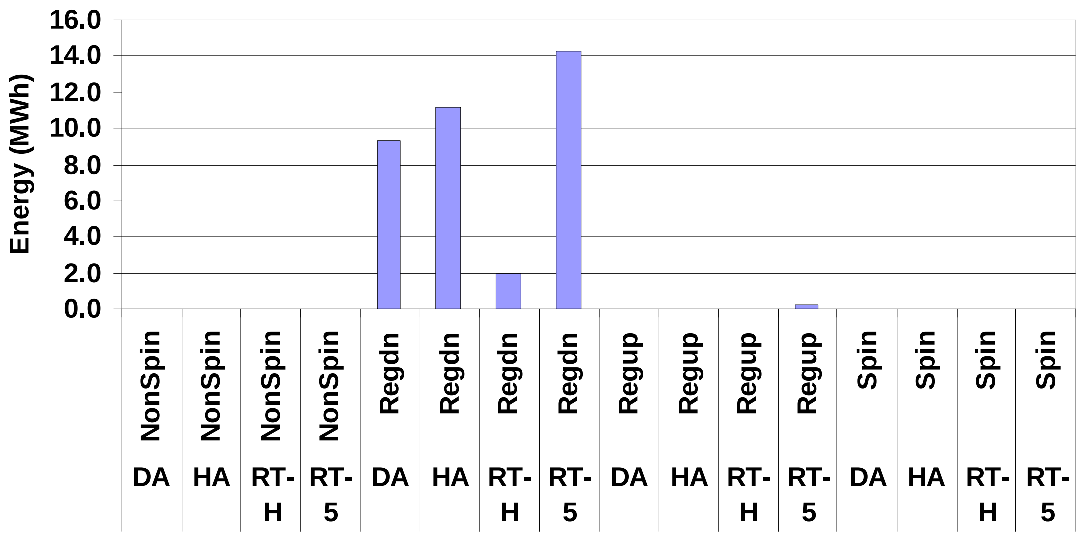


Figure C-19: May 22nd Operational Issues based on 2007 Load Shapes

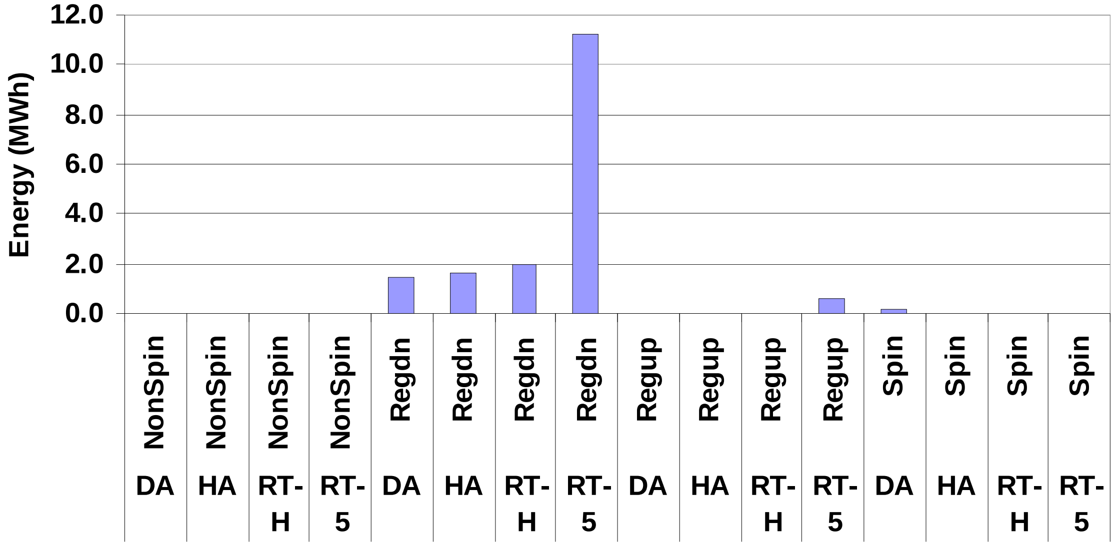


Figure C-20: May 23rd Operational Issues based on 2007 Load Shapes

EXHIBIT J

California ISO
Shaping a Renewed Future

Summary of Preliminary Results of 33% Renewable Integration Study – 2010 CPUC LTPP Docket No. R.10-05-006

May 10, 2011

SECTION 1:
INTRODUCTION AND OVERALL STATUS

Contents of Presentation

Introduction and Study Background:

- In a coordinated effort, the IOUs, E3, Plexos Solutions, Nexant, and the ISO conducted Step 1 and Step 2 modeling for the four renewable portfolio scenarios described in 12/3/10 Ruling:
  - Trajectory
  - Time Constrained
  - Cost Constrained
  - Environmentally Constrained
- The study results are dependent upon the scenario modeling assumptions described in the 12/3/10 CPUC scoping memo, with database modifications described in this presentation
- These preliminary results being provided according to schedule established in 3/1/11 Ruling
- ISO will conduct additional sensitivity analysis to validate preliminary results
- Final results will be provided with June 3 testimony

Study Coordination

- April 29 results were produced through a collaborative process between the IOUs and the ISO (and their contractors)
- ISO Activities:
  - Condition Step 1 and Step 2 input data. Contractor: Nexant
    - ISO also requested analytical support from E3, PLEXOS Solutions and IOUs. ISO made final decision on all Step 1 and Step 2 inputs.
  - Calculate Step 1 results. ISO using PNNL software
  - Calculate Step 2 results. Contractor: PLEXOS Solutions
    - ISO directed production of Step 1 and Step 2 results for all scenarios (IOUs did not produce Step 1 or Step 2 results independently of ISO)
- IOU Activities:
  - Calculate Step 3 results. Contractor: E3

Objectives of the 33% Renewable Integration Study and Role of the ISO

1. Identify operational requirements and resource options to reliably operate the ISO controlled grid (with some assumptions about renewable integration by other Balancing Authorities) 33% RPS in 2020
   - Provide estimates of operational requirements for renewable integration (measured in terms of operational ramp, load following and Regulation capacity and ramp rates, as well as additional capacity to meet operational reliability requirements)
   - Analyze sensitivity variables that affect the results
     - Impact of different mixes of renewable technologies and other complementary policies
     - Load growth
     - Impact of forecasting error and variability

Objectives of the 33% Renewable Integration Study and Role of the ISO (cont.)

2. Inform market, planning, and policy/regulatory decisions by the ISO, State agencies, market participants and other stakeholders
   - Support the CPUC to identify long-term procurement planning needs, costs and options
   - Inform other CPUC, and State agency, regulatory decisions (for example, Resource Adequacy, RPS rules, once through cooling [OTC] schedule)
   - In coordination with the CPUC, inform ISO and state-wide transmission planning needs to interconnect renewables up to 33% RPS
   - Inform design of ISO wholesale markets for energy and ancillary services to facilitate provision of integration capabilities

Study approach – overview of modeling tools utilized and proposed for LTPP methodology

- *Step 1* – Statistical Simulation to Assess Intra-Hour Operational Requirements
  - Estimates added intra-hour requirements under each studied renewable portfolio due to variability and forecast error
  - Calculates the following by hour and season: Regulation Up and Regulation Down capacity, load-following up and down capacity requirements, and operational ramp rate requirements
- *Step 2* – Production Simulation
  - Optimizes commitment and dispatch of resources in an hourly time-step to meet load, ancillary services and other requirements at least cost.
  - Uses Step 1 Regulation and load following capacity requirements to reflect intra-hourly operations
  - Calculates production cost-based energy prices, emissions, energy and ancillary services provided by units, violations of system constraints and additional capabilities required to eliminate violations

Status of ISO Methodology and Simulations

- Step 1 methodology under review for assumptions about solar forecast error
- Step 2 methodology reflects modified assumptions discussed in prior workshop (and reviewed in these slides) and additional modifications based on LTPP analysis
- Preliminary Step 2 simulation results now available for review
- Opportunities for further refinement of both Step 1 and Step 2 methodology prior to next batch of CPUC scenario assumptions
- Would like to continue working with the IOUs on an All Gas case, High Load Growth case and a 2011 base case

This presentation builds on prior ISO presentations at CPUC LTPP workshops

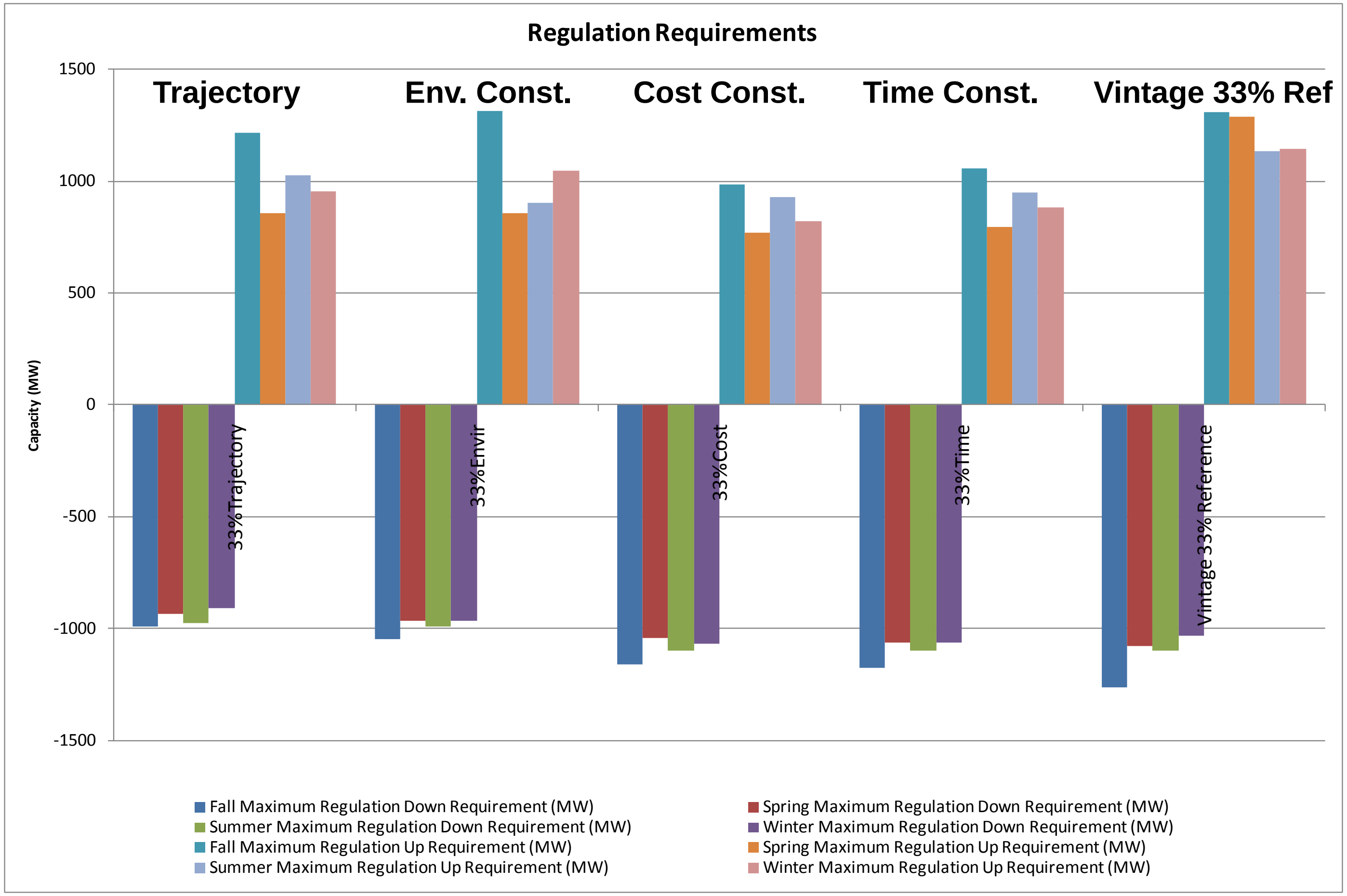
- These slides reference:
  - ISO August 24-25, 2010 presentation
  - ISO October 22, 2010 presentation
- Prior ISO slides available at
  - http://www.cpuc.ca.gov/PUC/energy/Renewables/100824_workshop.htm

SECTION 2:
OPERATIONAL REQUIREMENTS RESULTS (STEP 1)

Step 1 Operational requirement results

- Regulation and load following requirements determined 2010 CPUC-LTPP scenarios
- New load, wind and solar profiles were developed
- Updated load, wind and solar forecast errors were used to calculated requirements
- Refer to appendix for changes to profile and forecast error
- Load following requirement reduced from vintage cases due to reduced forecast errors
- Regulation requirements increased in some hours due to increase in 5 minute load forecast

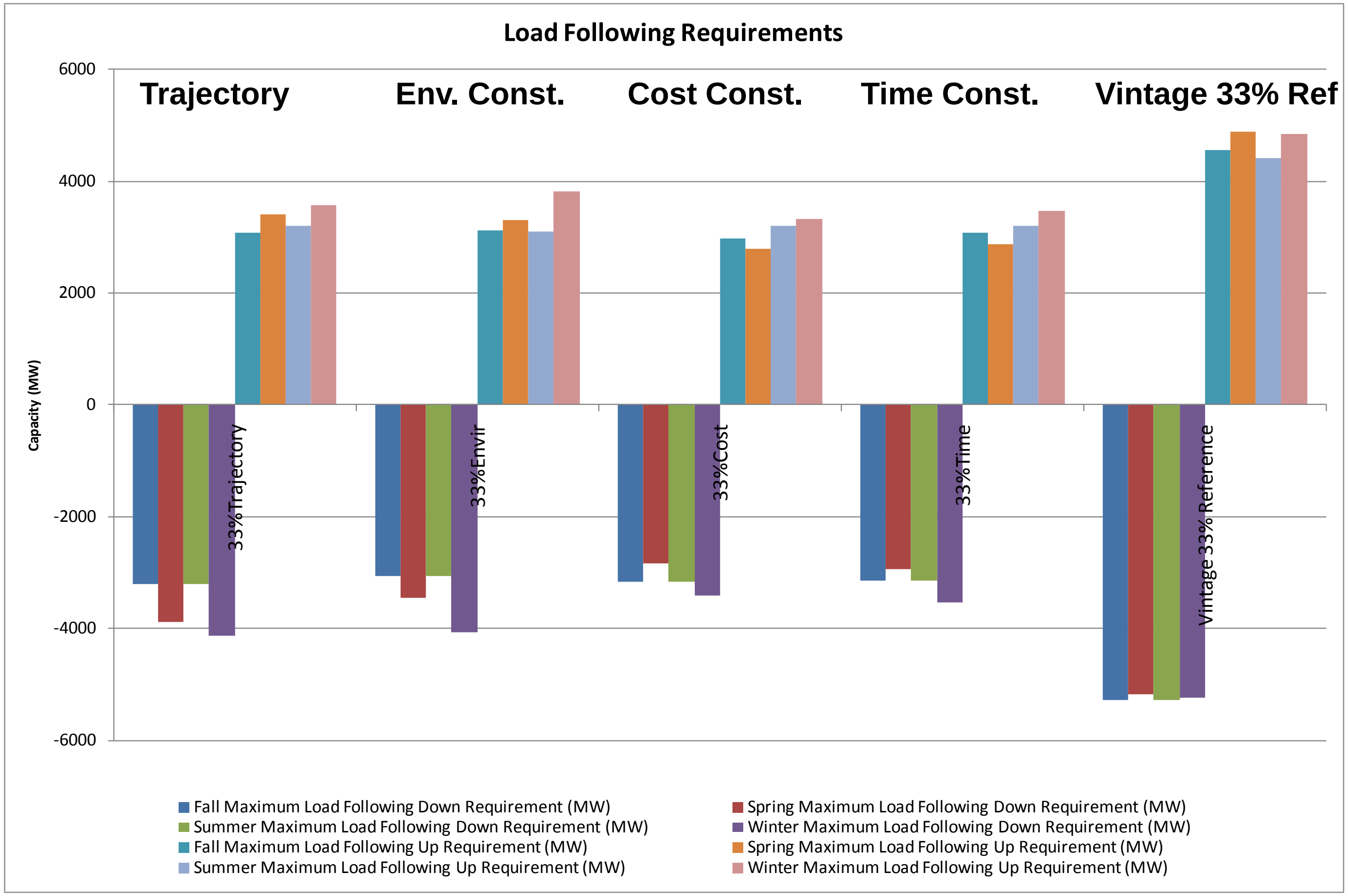
Step 1: Hourly regulation capacity requirements, by scenario



Notes:

- For purposes of comparison, the figures show the single highest hourly seasonal requirement from Step 1 for each season (using the 95th percentile)
- The actual cases use the maximum monthly requirement by hour for need determination and hourly value for production cost and emissions
- Discussion of sensitivity in Section 3

Step 1: Hourly load-following capacity requirements, by scenario



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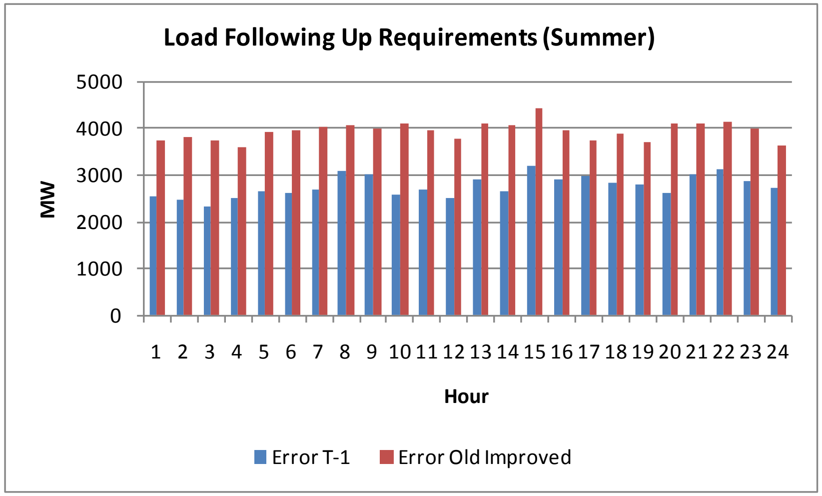
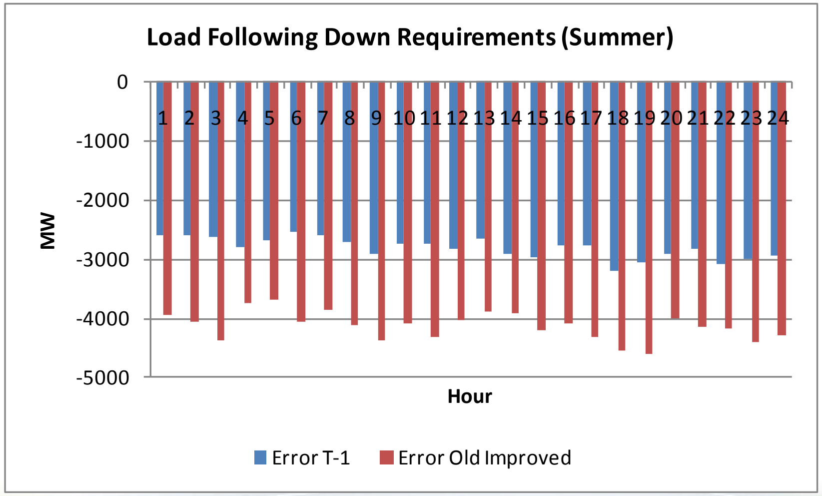
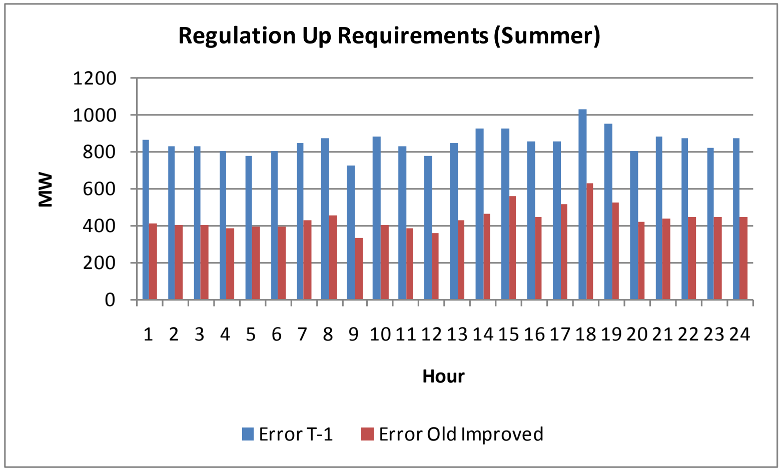
- Discussion of sensitivity in Section 3

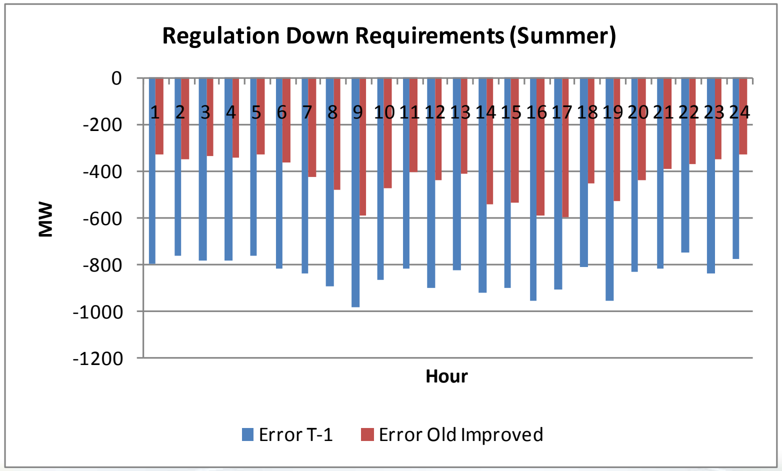
Comparison of load following requirements using refined and previous forecast error. Decrease in load following requirements reflect decrease in T-1 hour forecast errors.



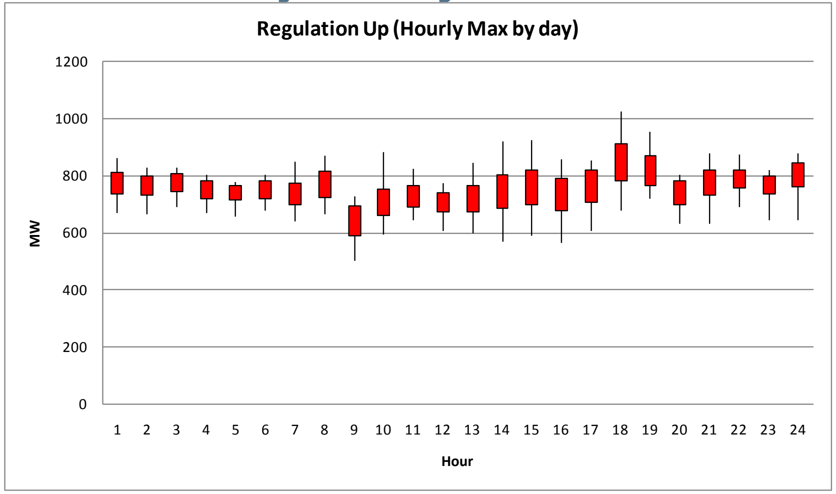


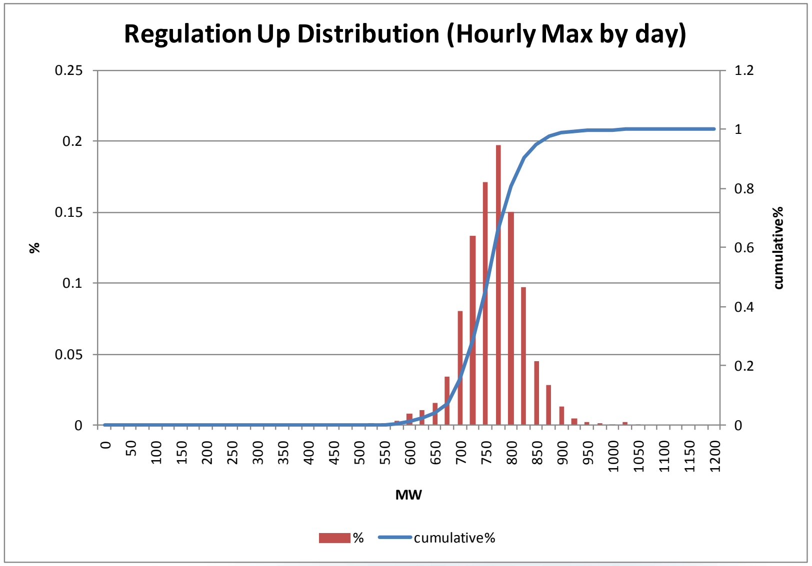
Comparison of regulation requirements using new and previous forecast error. Higher regulation requirement reflects 2010 actual T-7.5 forecast error high then 2006 assumption.



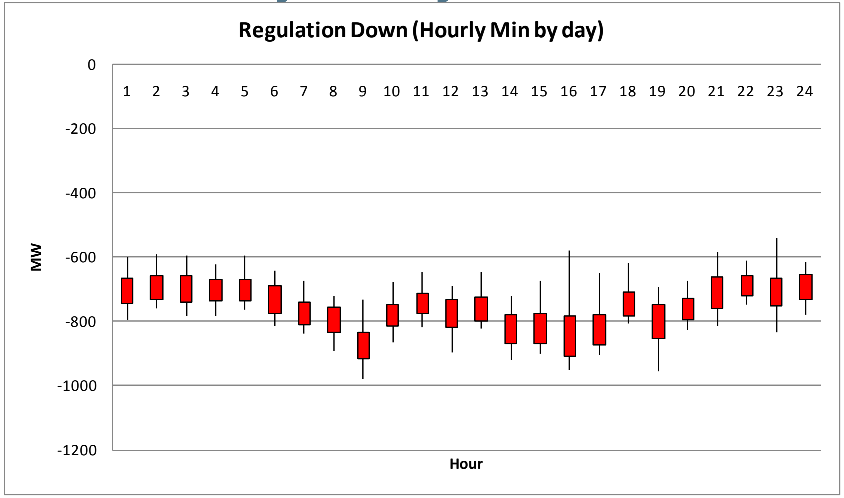


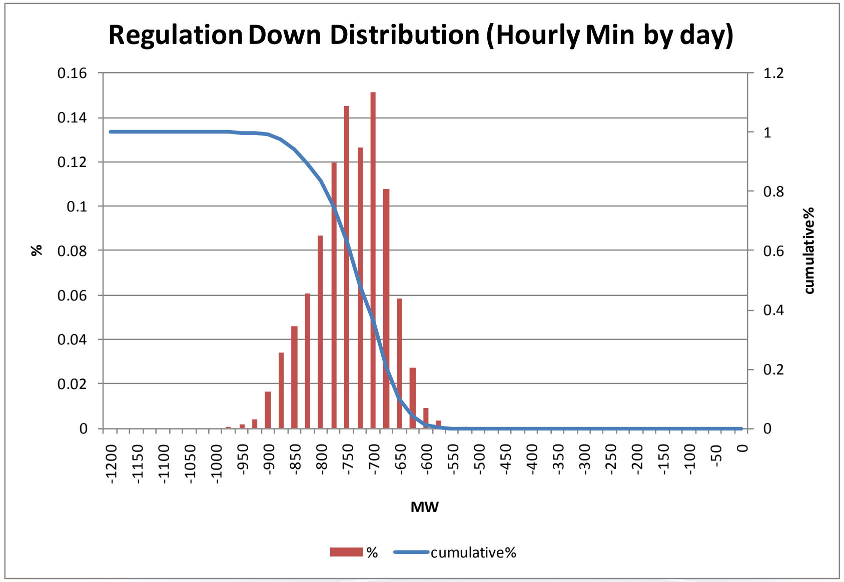
Summer 2020 regulation up capacity requirement – distributions of – 33% Trajectory



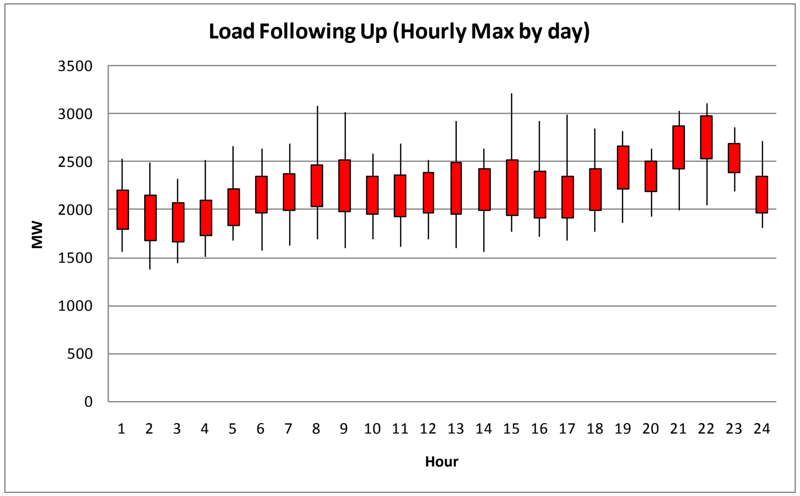


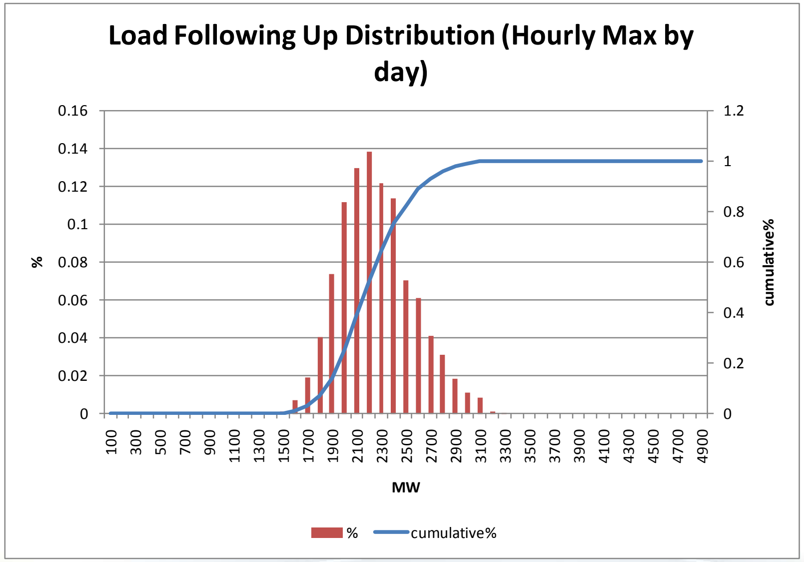
Summer 2020 regulation down capacity requirement – distributions of – 33% Trajectory



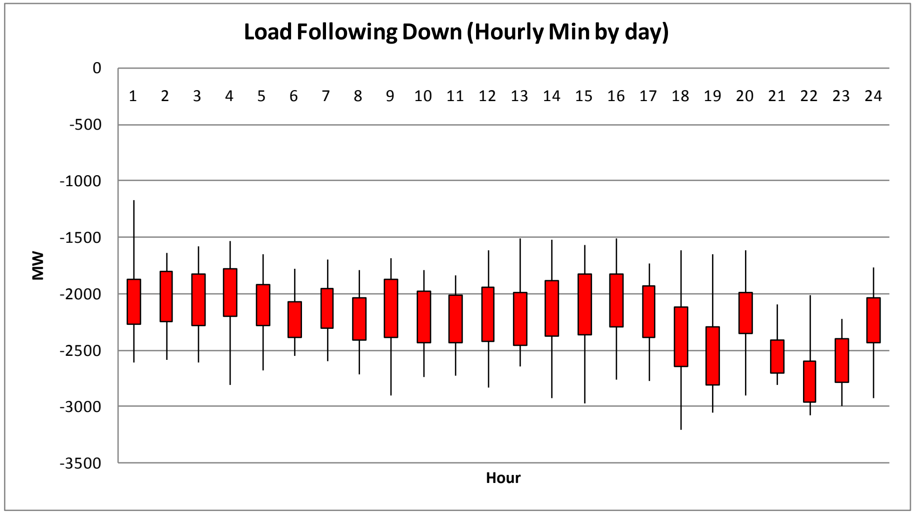


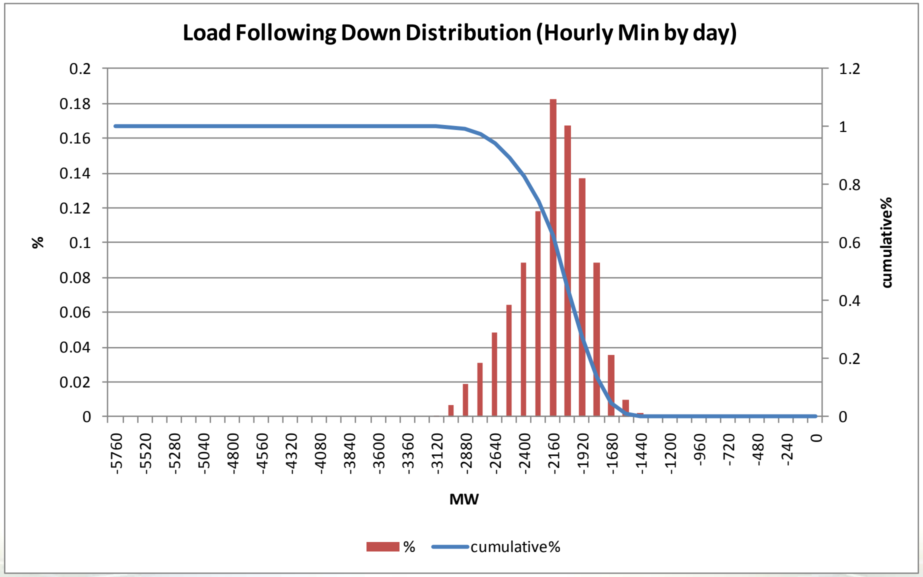
Summer 2020 load following up capacity requirement – distributions of – 33% Trajectory





Summer 2020 load following down capacity requirement – distributions of – 33% Trajectory





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SECTION 3:
PRODUCTION SIMULATION RESULTS FOR TRAJECTORY, ENVIRONMENTAL CONSTRAINED, COST CONSTRAINED AND TIME CONSTRAINED (STEP 2)

Initial comments on method and results

- The focus of the presentation is on initial results for four scenarios:
  - Trajectory, Environmental Constrained, Cost Constrained and Time Constrained
  - Review of these results continues to be conducted
- Results are function of assumptions load, renewable portfolio and forecast error which warrant sensitivity analysis
  - E.g., what range of operational requirements to model and how to interpret the implications
- Some results are a function of *ex post* processing of model outputs; alternative methods will yield different results within a range
  - E.g, allocation of import production costs to California load

Key common assumptions for production simulation cases

- WECC-wide model using latest PC0 dataset from the Transmission Expansion Planning Policy Committee (TEPPC) at WECC
- CPUC 2010-LTPP scenarios (renewable portfolios, load forecasts, planned retirements/additions)
- Conventional dispatchable generation modeled with generic physical operating parameters
  - Inventory of operational flexibility capability – load following, regulating ranges – reviewed in Section 4
- Import constraints enforced
- Path 26 and SCIT constraints enforced
- Out of state renewables:
  - 15% dynamic - 15% intra-hour (15 minute),
  - 40% hourly scheduled - 30% unbundled RECs where

Renewable portfolios for 2020: 2010 LTPP Scenarios

		Incremental Capacity (MW)							
Scenario	Region	Biomass/ Biogas	Geothermal	Small Hydro	Solar PV	Distributed Solar	Solar Thermal	Wind	Total
Trajectory	CREZ-North CA	3	0	0	900	0	0	1,205	**2,108**
	CREZ-South CA	30	667	0	2,344	0	3,069	3,830	**9,940**
	Out-of-State	34	154	16	340	0	400	4,149	**5,093**
	Non-CREZ	271	0	0	283	1,052	520	0	**2,126**
	Scenario Total	338	821	16	3,867	1,052	3,989	9,184	**19,266**
Environmentally Constrained	CREZ-North CA	25	0	0	1,700	0	0	375	**2,100**
	CREZ-South CA	158	240	0	565	0	922	4,051	**5,935**
	Out-of-State	222	270	132	340	0	400	1,454	**2,818**
	Non-CREZ	399	0	0	50	9,077	150	0	**9,676**
	Scenario Total	804	510	132	2,655	9,077	1,472	5,880	**20,530**
Cost Constrained	CREZ-North CA	0	22	0	900	0	0	378	**1,300**
	CREZ-South CA	60	776	0	599	0	1,129	4,569	**7,133**
	Out-of-State	202	202	14	340	0	400	5,639	**6,798**
	Non-CREZ	399	0	0	50	1,052	150	611	**2,263**
	Scenario Total	661	1,000	14	1,889	1,052	1,679	11,198	**17,493**
Time Constrained	CREZ-North CA	22	0	0	900	0	0	78	**1,000**
	CREZ-South CA	94	0	0	1,593	0	934	4,206	**6,826**
	Out-of-State	177	158	223	340	0	400	7,276	**8,574**
	Non-CREZ	268	0	0	50	2,322	150	611	**3,402**
	Scenario Total	560	158	223	2,883	2,322	1,484	12,171	**19,802**

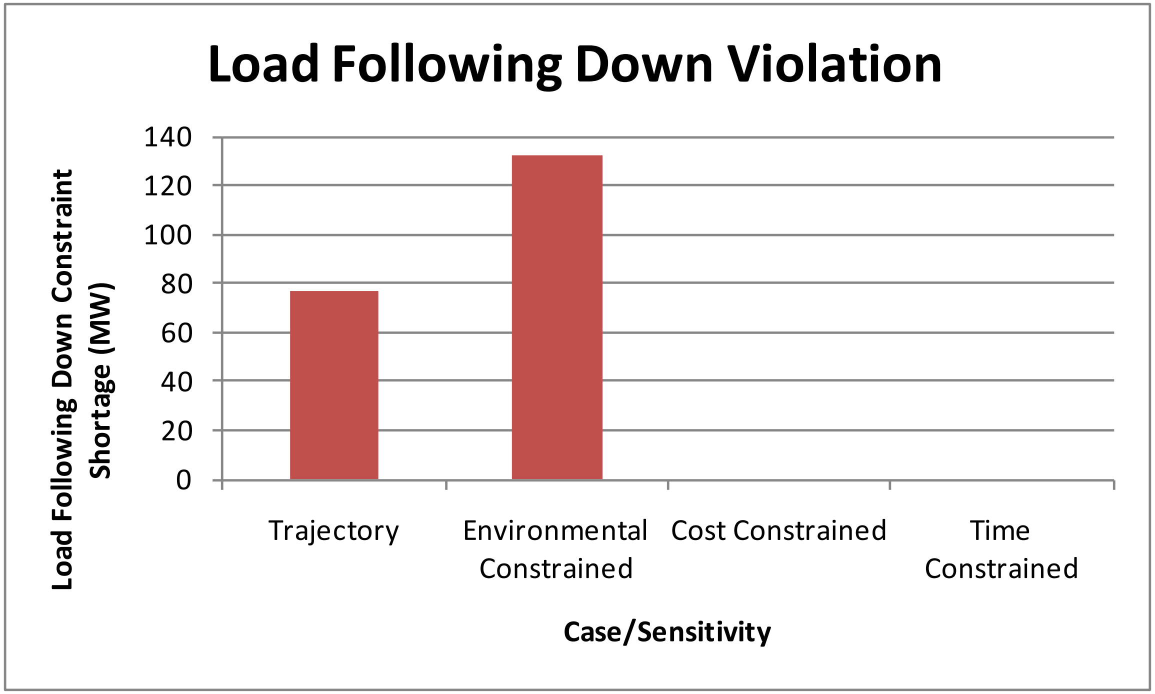
Production simulation results in this section reflect certain assumptions

- Intra-hourly operational needs from Step 1 assume monthly maximum requirements for each hour
  - Regulation, load-following
- Additional resources are added by the model to resolve operational constraints (ramp, ancillary services); this process determines potential need.
- Renewable resources located outside California to serve California RPS will create costs that will be paid for by California load-serving entities – see Step 3 results completed by California IOUs

The analysis adds resources above the defined case resource level to resolve to resolve operational violations

- LTPP analysis did not require adding any generic units to meet PRM because CPUC scoping memo assumptions create a 2020 base dataset that has a significant amount of capacity above PRM
- Next slide shows operational requirement shortages (constraint violations)
- Results for production costs, fuel use and emissions by scenario assume that these resources are added to generation mix

Under CPUC Scoping Memo assumptions, there are no upward constraints violations. There a few hours of load following down constraint violations. (Updated with revised outage profile)



Notes:

1. Consideration of other measures including curtailment should be considered to address load following down shortages
2. Based on limited hours and magnitude of load following down violations the traditional practice of adding generic proxy resources to relieve violation is NOT reflective of needs. However to relieve downward violations, 200MW, 300MW, 0MW and 0MW were introduced in simulations, for the respective trajectory, environmental, cost and time constrained cases

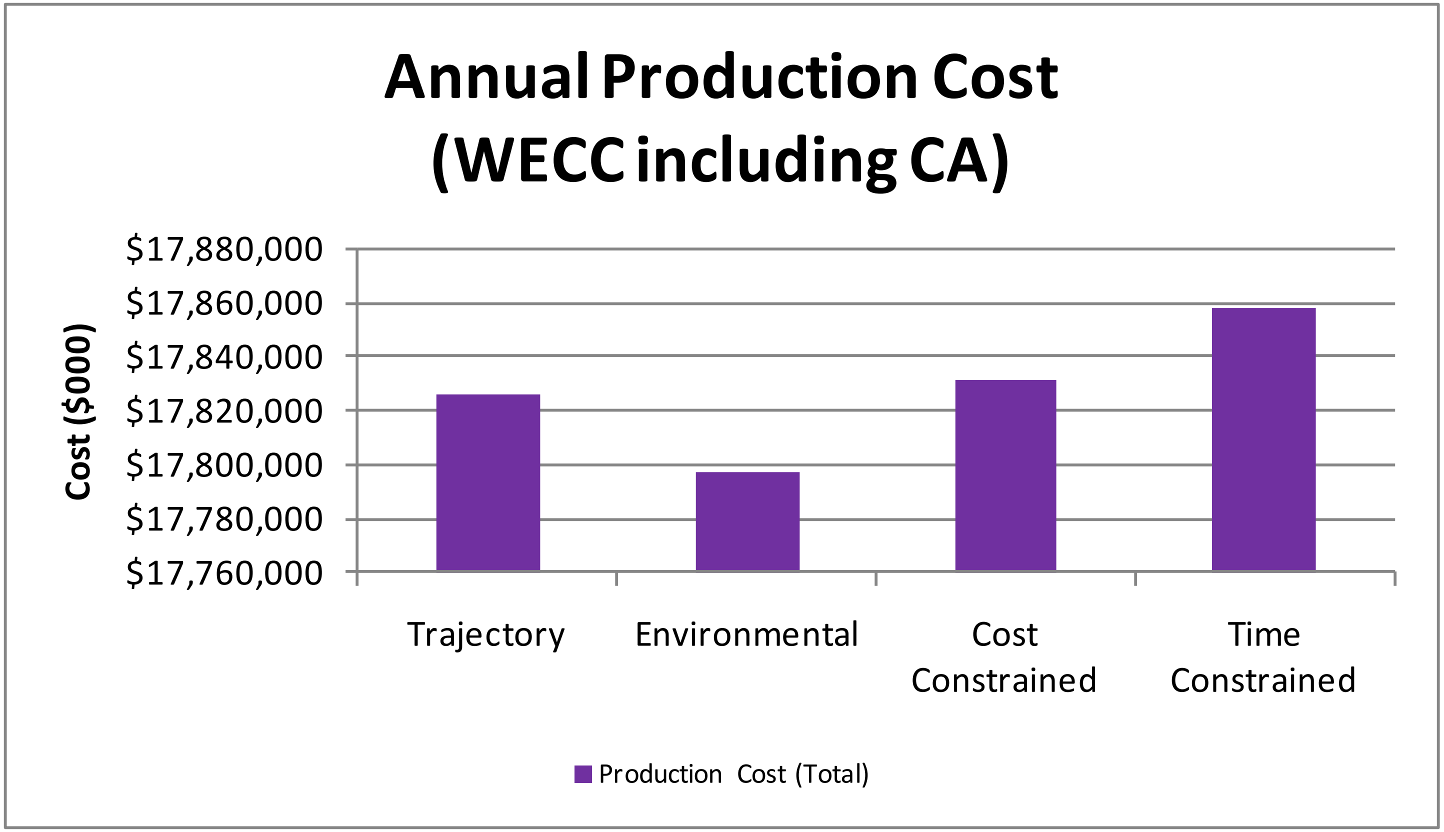
Discussion of results on additional resources

- No upward violations identified in the 2010 Trajectory, Environmental, Cost Constrained and Time Constrained scenarios due to combination of lower loads and reduced requirements
- Limited number of hours and magnitude of load following down violations warrant curtailment or other measures to resolve
- Results are sensitive to assumptions about load level, requirements based on forecast error, mix of resources, and maintenance schedules

Production costs and fuel consumption by scenario

- Production costs based primarily on generator heat rates and assumptions about fuel prices in 2020
- Trends in production costs related to fuel burn and variable O&M (VOM) costs are thus closely related
- Production costs have to be assigned to consuming regions by tracking imports and exports
- Costs associated with emission are tracked separately from fuel and VOM costs

Annual production costs ($) for California and rest of WECC by scenario



Notes:
1. Note scale differences are small
2. Values are in 2010$

Components for calculating California production costs

CA GENERATION COSTS

+

(CA IMPORTS – CA EXPORTS)

CA IMPORTS

- Dedicated Resources
  - Renewables
    - Firmed
    - Non-Firmed
  - Conventional Resources
    - i.e. Hoover, Palo Verde
- Undesignated (or non-dedicated) Resources
  - Marginal resources in various regions

CA EXPORTS

- Undesignated (or non-dedicated) Resources
  - Marginal resources within CA regions

Calculating total California production costs

+ CA Generation Costs

- Costs to operate CA units (fuel, VOM, start costs)

+ Cost of Imported Power (into CA)

- Dedicated Import Costs
- Undesignated (or non-dedicated) Import Costs
- Out of State renewables (zero production cost)

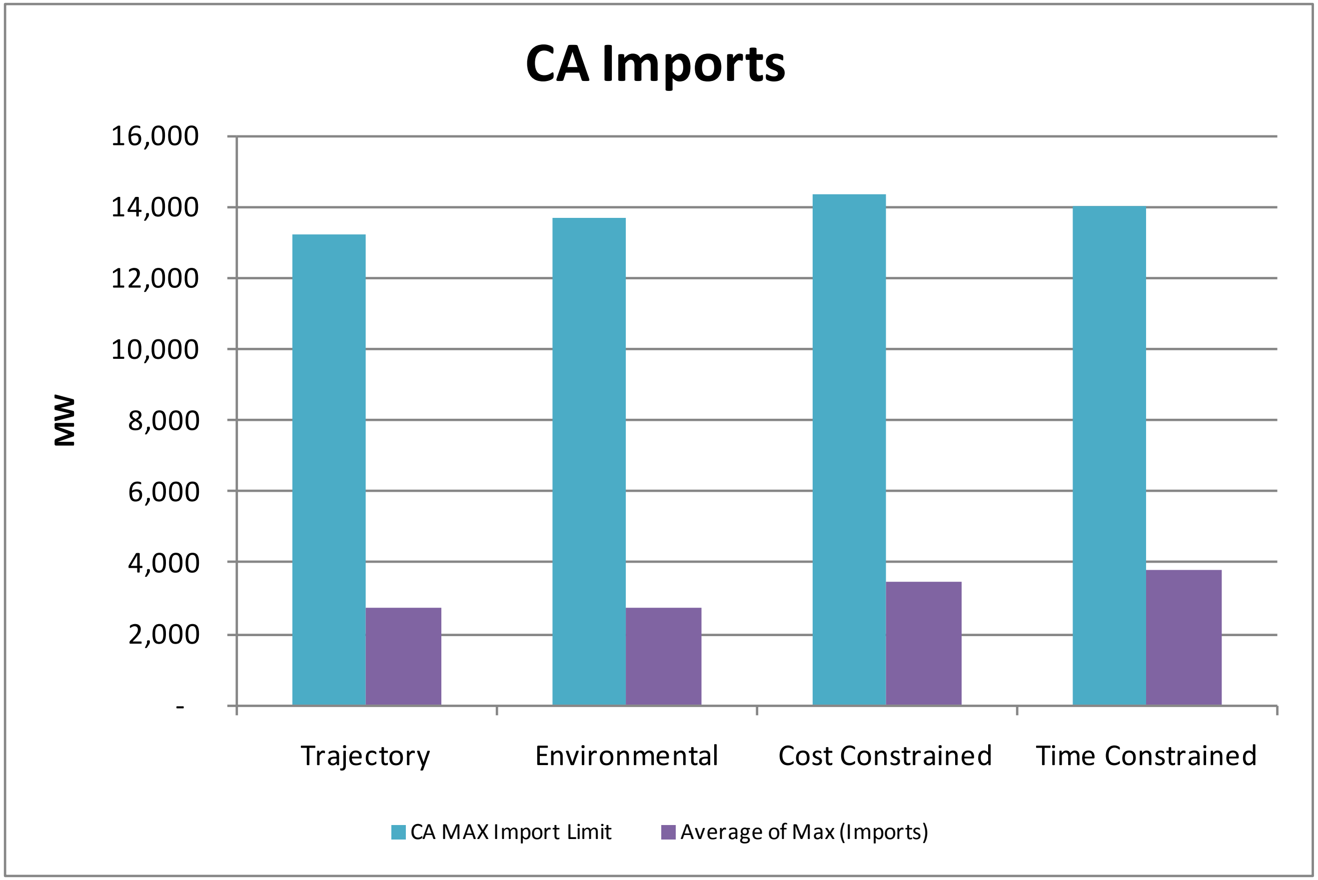
– Cost of Exported Power (out of CA)

- Undesignated (or non-dedicated) Export Costs

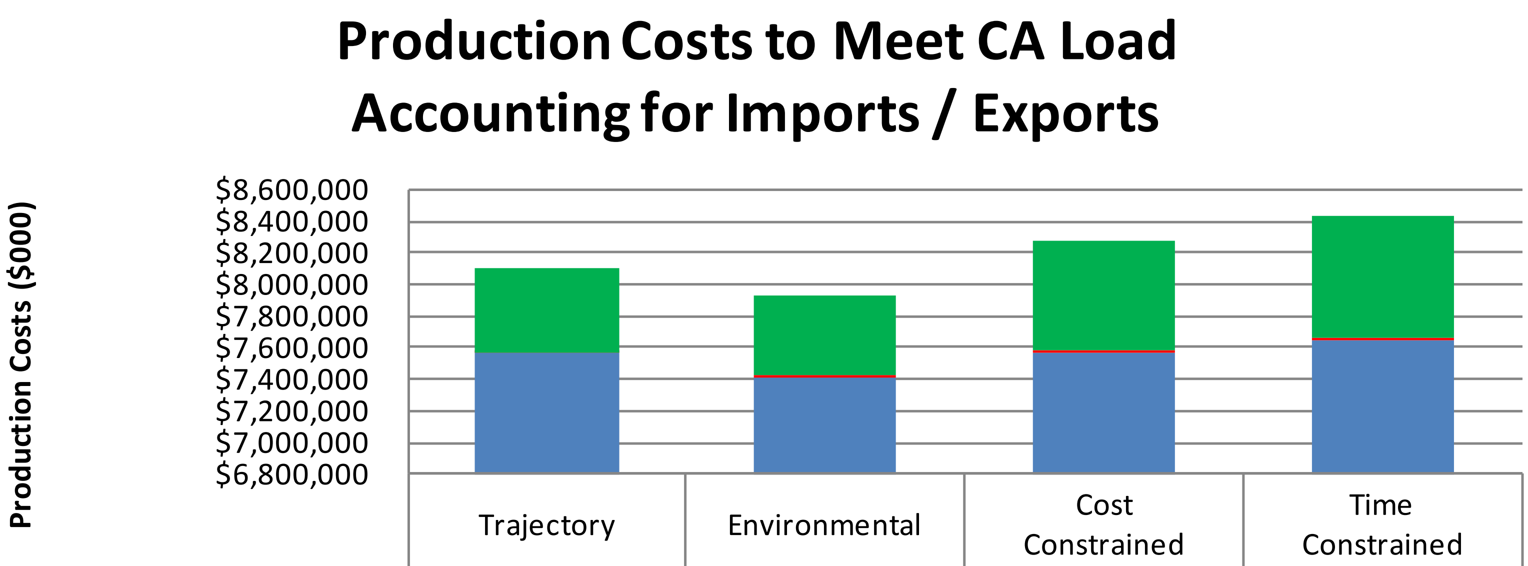
= Total Production Cost of meeting CA load

Note: Dedicated vs. Non-dedicated may also be known as specified or non-specified

Net Import results by scenario



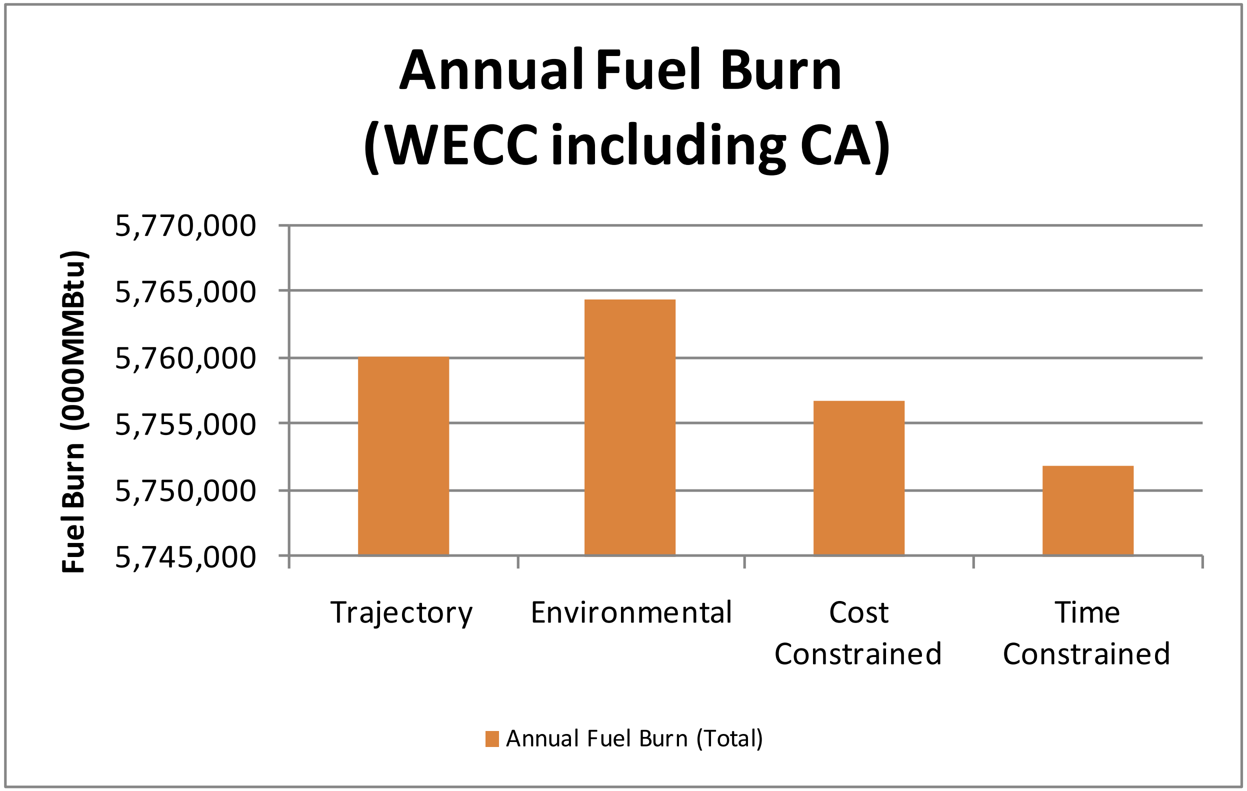
Total annual production costs ($) associated with California load (accounting for import/exports), by scenario



	Trajectory	Environmental	Cost Constrained	Time Constrained
Non-Dedicated	$529,620	$511,919	$698,702	$769,998
Dedicated	$9,195	$12,055	$9,649	$21,864
CA Generation Prod Costs	$7,566,554	$7,408,596	$7,570,102	$7,644,021

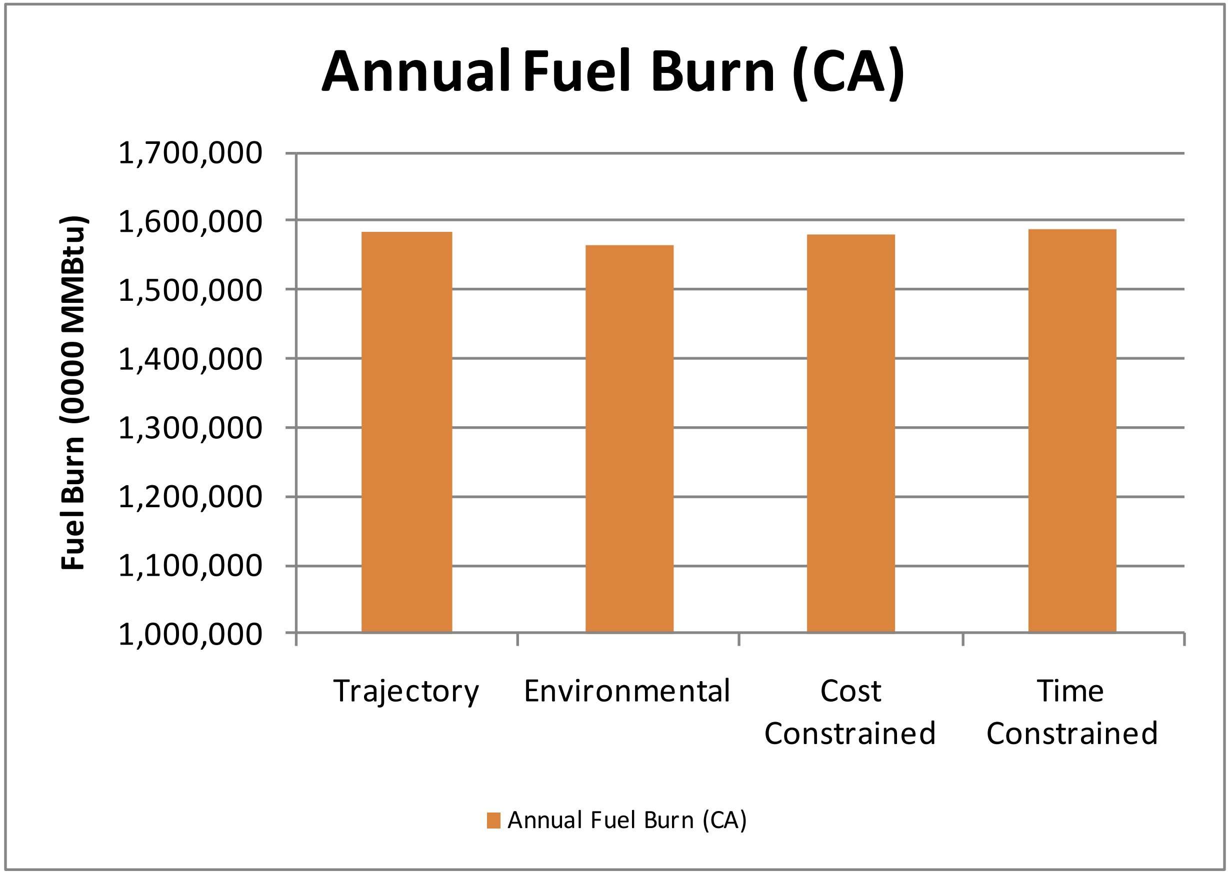
Note: IOUs have a step 3 accounting.   This slide reflect vintage method for accounting imports/exports. Energy credit for RECs is not accounted for in this. When the IOU do their Step 3 analysis this will be accounted for.

Total WECC (including CA) fuel burn (MMBTU), by scenario



MMBTU = million BTU for conventional/fossil resources

Total fuel burn (MMBTU) for in-state generation in California, by scenario



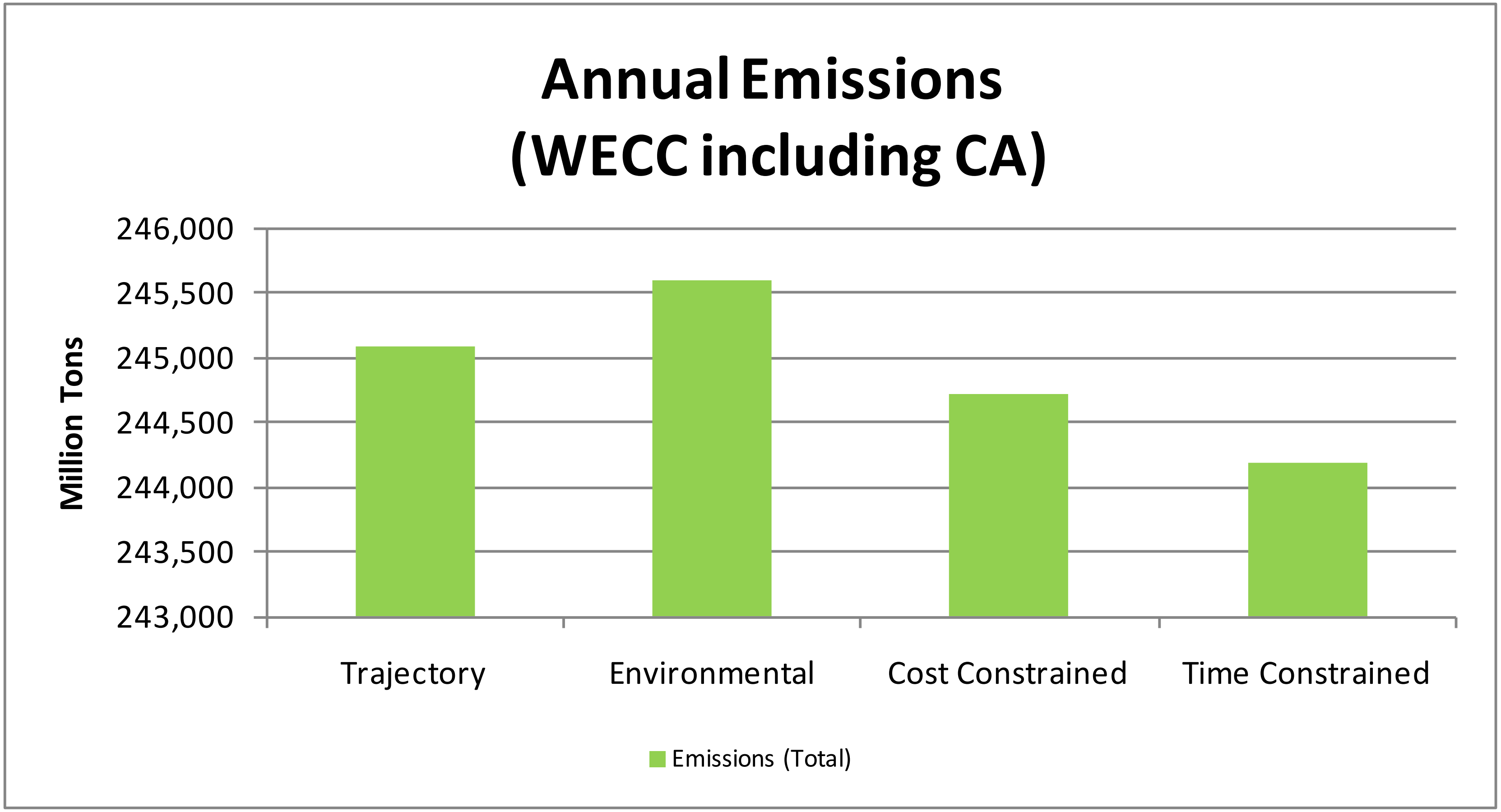
MMBTU = million BTU for conventional/fossil resources

GHG emissions calculations

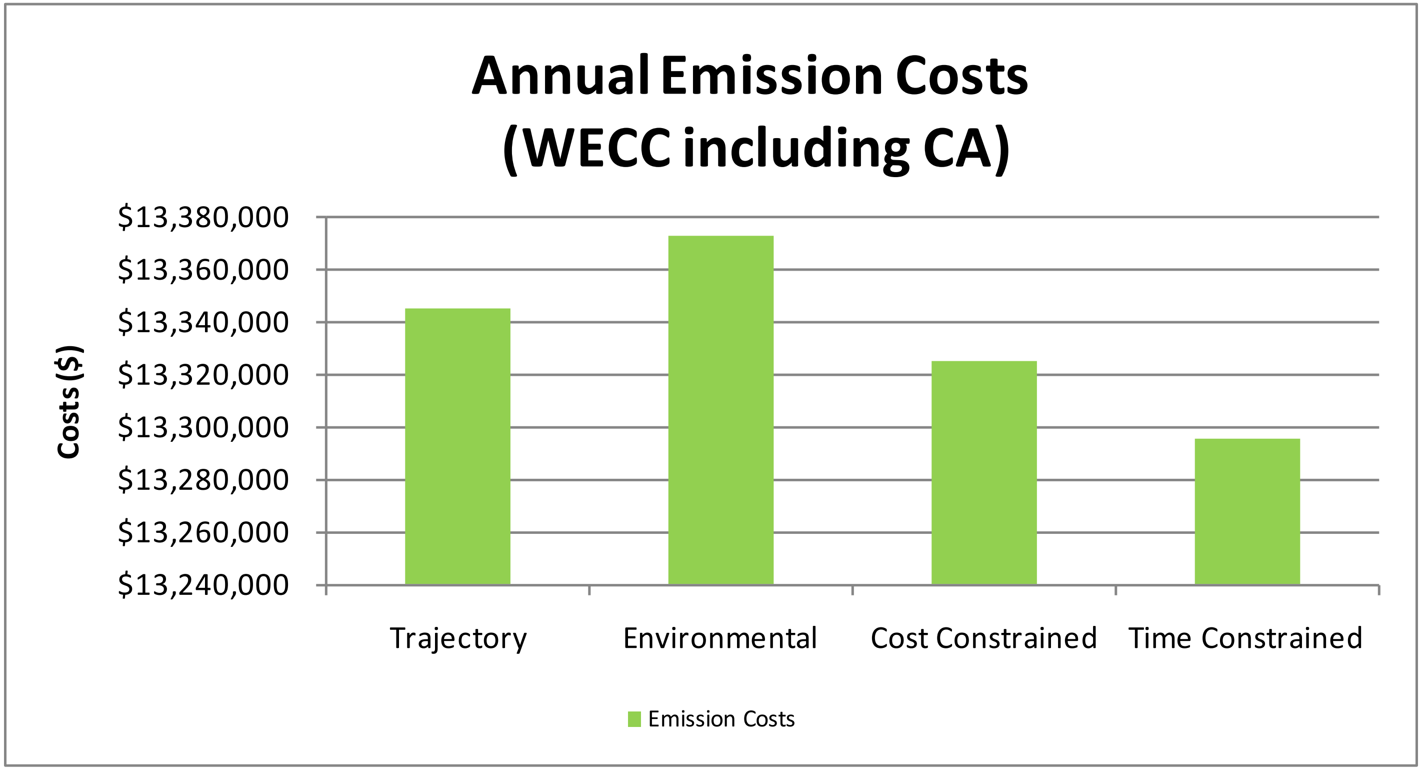
- GHG emissions are calculated by heat rate (MMBTU/MWh) × fixed emissions factor (lbs/MMBTU)
- Plants with multiple-step heat rate curves will have different emissions/MWh depending on their output in each hour of the simulation (two actual plants in table below)

Supply curve:		Segment 1	Segment 2	Segment 3
Plant 1	MW	68	170	340
	Heat rate	11750	10100	9600
Plant 2	MW	263	394	525
	Heat rate	8000	7300	7000

Annual WECC emissions by scenario



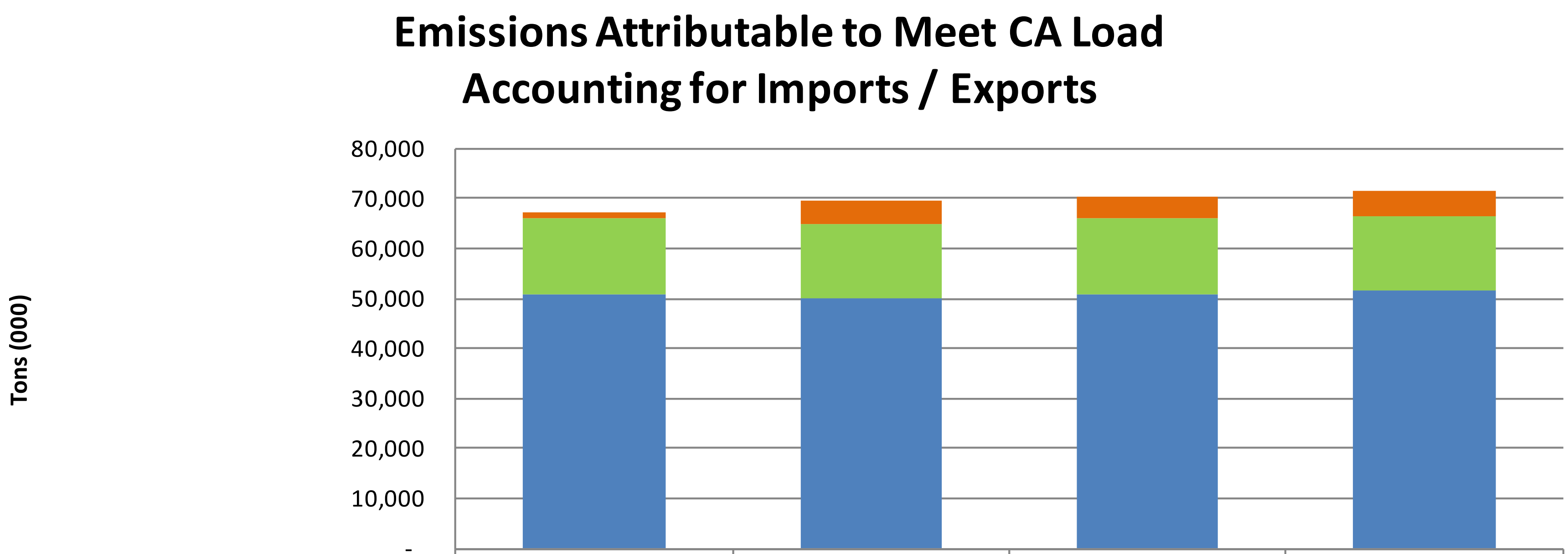
Annual WECC emission costs by scenario



Calculation of emissions associated with California

- Production simulation modeling output includes GHG emissions (tons/MMBTU) per generator to capture WECC-wide emissions reductions, but:
  - The model solves for the WECC without considering contractual resources specifically dedicated to meet California load
  - Not all OOS RPS energy dedicated to CA may "flow" into CA for every simulated hour as it could in actual operations (thus reducing emissions in CA)
- To ensure that the emissions benefit of OOS RPS energy dedicated to California is counted towards meeting California load, the study uses an *ex post* emissions accounting method (next slide)

Emissions attributed to meet California load (accounting for Import/Exports[1]), by scenario and emissions source



	Trajectory	Environmental	Cost Constrained	Time Constrained
Emissions from Non-Dedicated Import	1,464	4,696	4,471	5,223
Emissions from Dedicatied Imports	14,932	14,923	14,897	14,929
CA Emissions	51,013	49,912	51,035	51,561

1. Emissions associated with non-specified imports are attributed to CA based on an assumed emissions rate of .44 metric tons/MWh

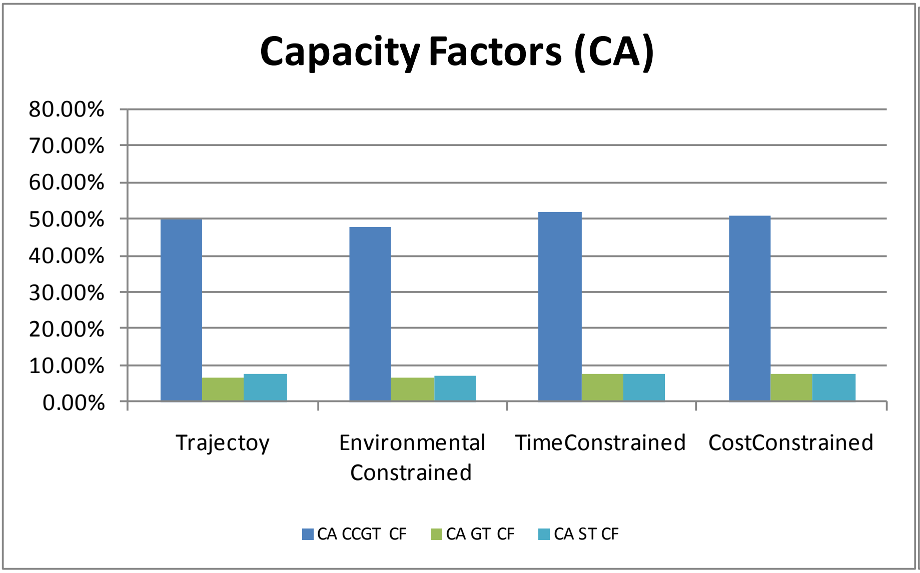
Discussion of emissions results

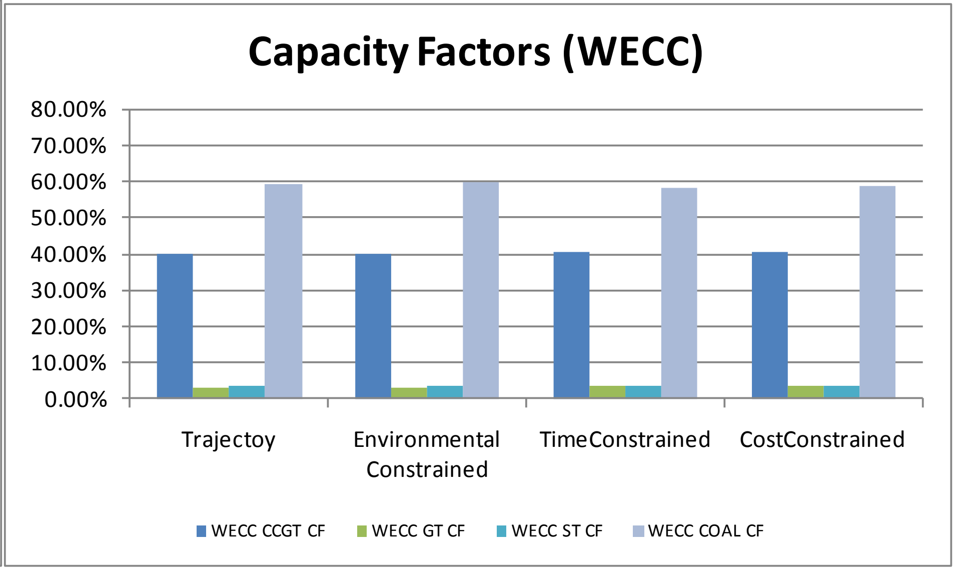
- Total emissions reduction assigned to California includes contribution of imports
- Emissions impact from California in-state generation is due in part to operational requirements associated with integration
  - Total emissions from California generators are lower in the sensitivity analysis on operational requirements discussed in Section 3
- Results are sensitive to method for allocating renewable energy imports to California load

Changes to fleet operations

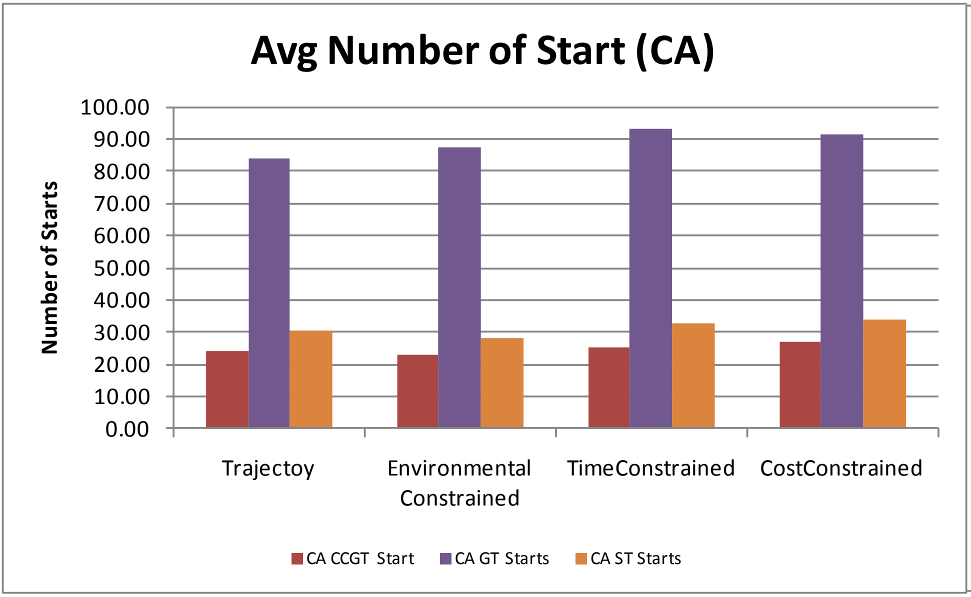
- Changes in capacity factors, number of starts by unit type and location
- California within-state results are influenced by integration requirements within state
- Linked to production costs and emissions, as shown in earlier slides

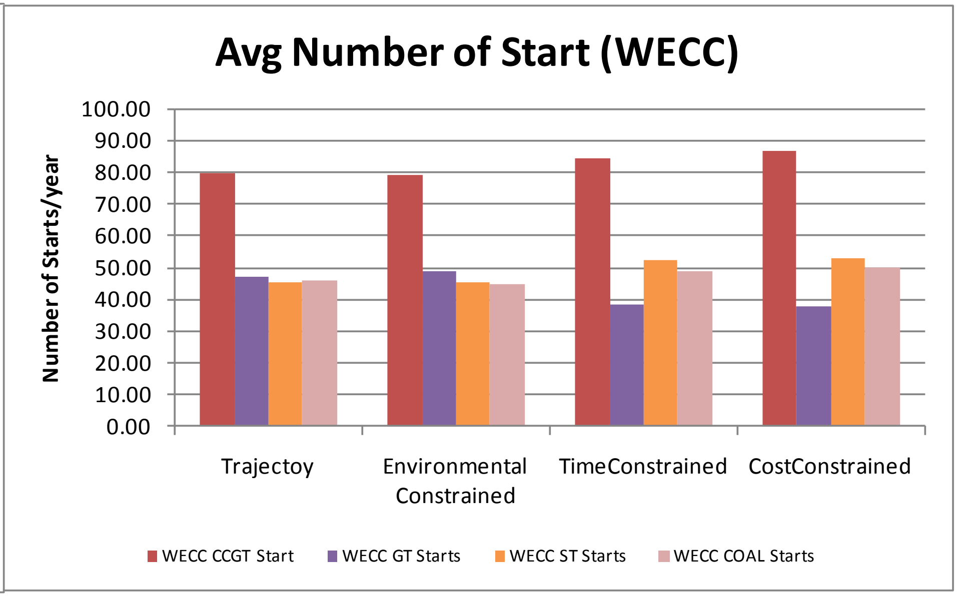
Changes to Capacity Factors, by scenario





Changes to number of Start-ups, by scenario





Comparison of CA and WECC (exclusive of CA) Results (2)

Comparison of Dispatchable Resources (CA versus WECC) (Trajectory)

Technology	CA		WECC		Difference (CA-WECC)	
	Avg CF	Avg Unit S	Avg CF	Avg Unit S	Avg CF	Avg Unit Starts
CCGT	49.71%	24.00	40.19%	79.69	9.52%	-55.69
Coal	N/A	N/A	59.14%	45.92	N/A	N/A
GT	6.86%	84.23	3.07%	47.35	3.79%	36.88
ST	7.47%	30.69	3.57%	45.28	3.90%	-14.59

Comparison of Dispatchable Resources (CA versus WECC) (Environmental Constrained)

Technology	CA		WECC (Excl CA)		Diff(CA-WECC)	
	Avg CF	Avg Unit Starts	Avg CF	Avg Unit Starts	Avg CF	Avg Unit Starts
CCGT	47.82%	22.72	40.18%	79.29	7.64%	-56.57
Coal	N/A	N/A	59.58%	44.71	N/A	N/A
GT	6.67%	87.59	3.06%	48.83	3.61%	38.76
ST	7.37%	28.00	3.56%	45.51	3.81%	-17.51

Comparison of Dispatchable Resources (CA versus WECC) (Time Constrained)

Technology	CA		WECC (Excl CA)		Diff (CA-WECC)	
	Avg CF	Avg Unit Starts	Avg CF	Avg Unit Starts	Avg CF	Avg Unit Starts
CCGT	51.60%	25.56	40.70%	84.34	10.90%	-58.79
Coal	N/A	N/A	58.40%	48.77	N/A	N/A
GT	7.63%	92.89	3.35%	38.49	4.28%	54.40
ST	7.51%	33.00	3.74%	52.06	3.77%	-19.06

Comparison of Dispatchable Resources (CA versus WECC) (Cost Constrained)

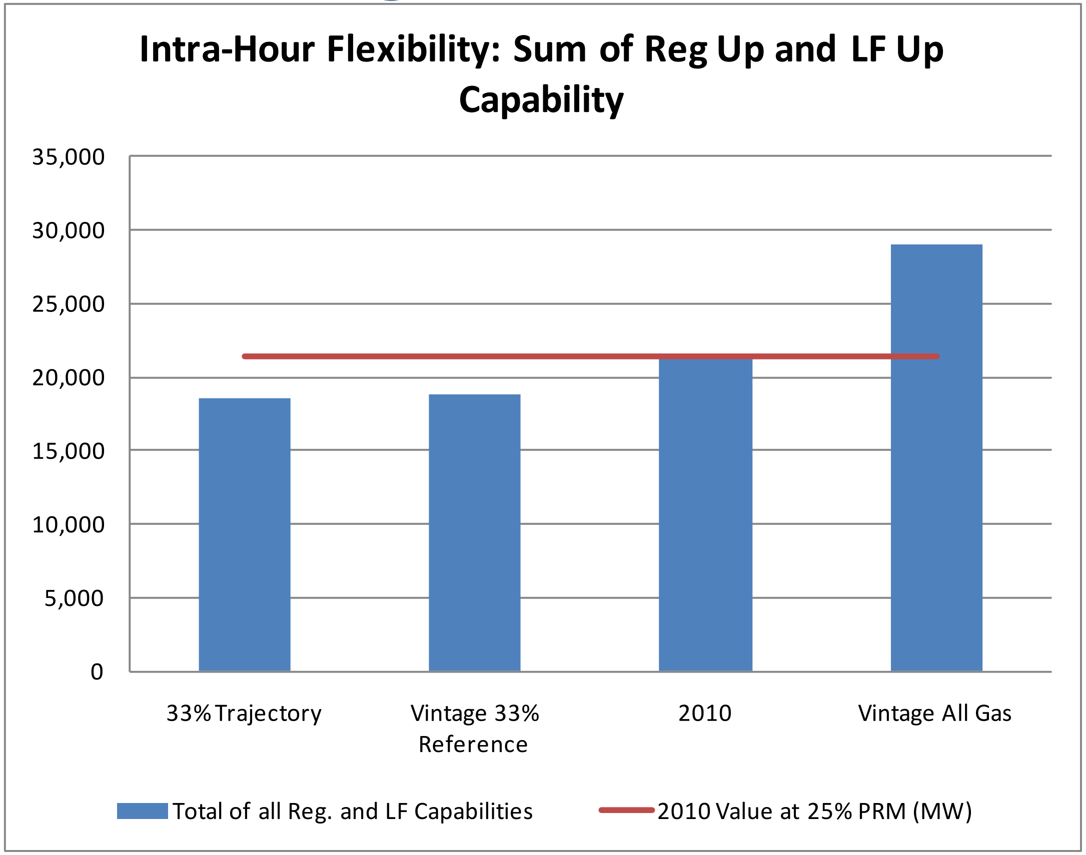
Technology	CA		WECC (Excl CA)		Diff (CA-WECC)	
	Avg CF	Avg Unit Starts	Avg CF	Avg Unit Starts	Avg CF	Avg Unit Starts
CCGT	50.78%	27.07	40.59%	86.43	10.19%	-59.35
Coal	N/A	N/A	58.90%	50.30	N/A	N/A
GT	7.72%	91.39	3.42%	37.82	4.30%	53.58
ST	7.64%	34.00	3.82%	52.99	3.82%	-18.99

SECTION 4:
FURTHER ANALYSIS OF FLEET FLEXIBILTY IN 2020

Analysis of generation fleet flexibility in 2020

- Prior presentations provided analysis of fleet flexibility
- Updated fleet flexibility analysis for 2010-CPUC LTPP trajectory scenario
- The following compares the fleet flexibility with vintage "33% reference" and "all gas" cases as well as 2010 existing

Analysis of generation fleet flexibility in 2020, with comparison with vintage cases and 2010



- The blue bar reflects the fleet flexibility of the resource fleet in the trajectory case and fleet to meet PRM in the vintage cases
- Fleet flexibility decreases as OTC resources are replaced by renewables

SECTION 5:
RECOMMENDATIONS AND NEXT STEPS

Preliminary observations

- Assuming CA achieves demand side objectives preliminary results indicate most operational requirements can be satisfied with potential need for measures to address some over-generation conditions
- Operational requirements are dependent on load, wind and solar forecast error assumptions, mix of renewable resources and outages
  - Initial sensitivities using vintage regulation and higher load following requirements indicate potential for shortages including load following up

Recommendations and next steps

- Recommend updating analysis in future years as assumptions evolve and more is known
- Continue to evaluate forecast error with actual data as additional data is available
- Recommend running additional sensitivities to:
  - Assess higher loads
  - Assess changes to forecast error and requirements
  - Evaluate generation outages
  - Assess resources needed for local capacity requirements
  - Additional evaluation storage, pump hydro and demand response
  - Assess different assumptions of dynamic transfers

APPENDIX:
PRODUCTION SIMULATION MODEL CHANGES

Overview of Step 2 Database and Modeling

- To conduct the LTPP Step 2 analysis, an up-to-date PLEXOS database was required
- ISO used the 33% operational study PLEXOS database as a starting point
- Input data from this database were changed to align with the assumptions in the CPUC scoping memo
- Non-specified assumptions were updated by the ISO to reflect operational feasibility and to include the best publically available data
- To ensure the April 29th deadline was met, PLEXOS implemented several modeling enhancements to improve simulation efficiency

Key Inputs

- Two sets of key inputs: CPUC specified assumptions and non-specified assumptions updated by the ISO
- Assumptions stated in the CPUC Scoping Memo
  - Load forecast that includes demand side reductions
  - Renewable resource build-out
  - Existing, planned and retiring generation
  - Maximum import capability to California
  - Gas price methodology for California
  - CO_2 price assumption
- Non-specified assumptions updated by the ISO
  - Allocation of reserve requirements between ISO and munis
  - Generator operating characteristics and profiles
  - Operational intertie limits
  - Loads, resources, transmission and fuel prices outside of California

CPUC SPECIFIED ASSUMPTIONS

Load – Load Profiles

- Nexant created a load profile that was consistent with the CPUC's forecasted load for the analysis of the four LTPP scenarios
- Load profile adjustment made to the CPUC specified demand side resources
  - Energy efficiency
  - Demand side CHP
  - Behind-the-meter PV – modeled as supply
  - Non-event based DR

Generation - CPUC Generation Dataset

- CPUC provided data on existing, planned and retiring generation facilities
- Existing resources specified by the CPUC were drawn from two resources:
  - 2011 NQC as of August 2^{nd}, 2010
  - ISO master generation list
- Additions and non-OTC retirements are drawn from the ISO OTC scenario analysis tool; other additions are resources with CPUC approved contracts that do not have AFC permits approved
  - CCGTs in CPUC planned additions were modeled with generic unit operating characteristics taken from the MPR
- OTC retirements taken from the State Water Board adopted policy with several CPUC modifications

CPUC Supply Side CHP and DR Specifications

- Existing CHP and DR bundles in the 33% operational study PLEXOS database were scaled to match the incremental supply side CHP and DR goals in the CPUC scoping memo
- 761 MW of incremental supply side CHP was assumed to be online in 2020 with a heat rate of 8,893 Btu/kWh per the CPUC scoping memo
- 4,817 MW of incremental DR was modeled as supply in 2020 (including line losses)
  – Non-event based DR was included in the load profiles and not in the Step 2 database as supply side resource

Load and Resource Balance with CPUC assumptions

- The CPUC Scoping Memo assumptions estimate a 17,513 MW surplus above PRM in 2020 in the ISO

Load and Resource Balance in the ISO using CPUC Resource Assumptions (MW)

	2011	2012	2013	2014	2015	2016	2017	2018	2019	2020
Load										
ISO Summer Peak Load	49,143	49,902	50,678	51,283	51,913	52,555	53,246	53,905	54,571	55,298
Total Demand Side Reductions	(3,432)	(4,712)	(5,650)	(6,374)	(7,187)	(8,036)	(8,936)	(9,874)	(10,776)	(11,651)
Net ISO Peak Summer Load	45,711	45,190	45,028	44,909	44,726	44,519	44,310	44,031	43,795	43,647
Resources										
Existing Generation	52,435	52,435	52,435	52,435	52,435	52,435	52,435	52,435	52,435	52,435
Retiring Generation	(1,260)	(1,425)	(1,425)	(2,434)	(4,694)	(5,646)	(10,378)	(11,329)	(12,280)	(14,357)
Planned Additions (Thermal, RPS, CHP)	1,747	4,388	6,728	7,336	10,558	11,280	12,207	12,283	13,471	13,547
Net Interchange (Imports - Exports)	16,955	16,955	16,955	16,955	16,955	16,955	16,955	16,955	16,955	16,955
Summary										
Total System Available Generation	69,877	72,353	74,693	74,292	75,254	75,024	71,219	70,344	70,581	68,580
Total System Capacity Requirement (PRM)	53,482	52,872	52,683	52,544	52,329	52,087	51,843	51,516	51,240	51,067
Surplus	**16,395**	**19,480**	**22,010**	**21,748**	**22,924**	**22,936**	**19,376**	**18,827**	**19,340**	**17,513**

Updating Generation Data in 33% Operational Database

- **The generation data in the 33% operational database were updated to reflect the specified existing, planned and retiring facilities in the CPUC scoping memo**
- **ISO also solicited feedback from the working group, stakeholders via market ISO market notice and also all parties on the LTPP service list on generator operating characteristics which was incorporated into the Step 2 database**
- **ISO found some discrepancies in the CPUC generation assumptions which it has corrected in its Step 2 database and accounting:**
  - Double-counting of the Ocotillo facility
  - Renewable resource capacity additions above what is chosen in the 33% RPS calculator
  - Double counting of several resources as both imports and resources

Ocotillo/Sentinel Generation

- CPUC scoping memo includes two separate facilities in its planned additions for Ocotillo (455 MW) and Sentinel (850 MW)
- Ocotillo is a subset of the Sentinel facility (units 1-5)
  - SCE signed a contract with Sentinel for an additional three units in 2008
- ISO Step 2 database only includes eight Sentinel units (850 MW) because Ocotillo (455 MW) is already accounted for in Sentinel's nameplate capacity

RPS Resources above 33%

- CPUC included 287 MW of RPS resources in its planned additions that are not included in the 33% RPS scenarios:
  - CalRENEW-1(A) (5 MW)
  - Copper Mountain Solar 1 PseudoTie-pilot (48 MW)
  - Vaca-Dixon Solar Station (2 MW)
  - Blythe Solar 1 Project (21 MW)
  - Calabasas Gas to Energy Facility (14 MW)
  - Chino RT Solar Project (2 MW)
  - Chiquita Canyon Landfill (9 MW)
  - Rialto RT Solar (2 MW)
  - Santa Cruz Landfill G-T-E Facility (1 MW)
  - Sierra Solar Generating Station (9 MW)
  - Celerity I (15 MW)
  - Black Rock Geothermal (159 MW)
- If included, these resources will create RPS scenarios that are above 33% RPS
- These resources were not profiled in the Step 1 analysis
- ISO did not include these resources in the Step 2 database

Existing Generation/Imports Discrepancies

- The 2011 NQC list includes 2,626 MW of resources that are imports to the ISO
  - APEX_2_MIRDYN (505 MW)
  - MRCHNT_2_MELDYN (439 MW)
  - MSQUIT_5_SERDYN (1,182 MW)
  - SUTTER_2_PL1X3 (500 MW)
- The CPUC's original L&R tables counted the capacity of these resources twice:
  1. Directly, as specified resources with NQC capacity
  2. Indirectly, by assuming full transmission capability into the ISO
- For accounting purposes and to avoid double accounting, ISO has removed these resources from the available generation but maintains the assumption of full transmission capability into the ISO

Load and Resource Balance After Assumption Modifications

- Accounting for all of these modifications, the load and resource balance has a surplus of 14,144 MW above PRM in 2020, compared to 17,513 MW above PRM using the CPUC assumptions

Load and Resource Balance in the ISO using CAISO Resource Modifications (MW)

	2011	2012	2013	2014	2015	2016	2017	2018	2019	2020
Load										
Summer Peak Load	49,143	49,902	50,678	51,283	51,913	52,555	53,246	53,905	54,571	55,298
Total Demand Side Reductions	3,432	4,712	5,650	6,374	7,187	8,036	8,936	9,874	10,776	11,651
Net Peak Summer Load	45,711	45,190	45,028	44,909	44,726	44,519	44,310	44,031	43,795	43,647
Resources										
Existing Generation	49,809	49,809	49,809	49,809	49,809	49,809	49,809	49,809	49,809	49,809
Retiring Generation	(1,260)	(1,425)	(1,425)	(2,434)	(4,694)	(5,646)	(10,378)	(11,329)	(12,280)	(14,357)
Planned Additions (Thermal, RPS, CHP)	1,618	4,259	6,440	7,048	9,815	10,537	11,464	11,540	12,728	12,804
Net Interchange (Imports - Exports)	16,955	16,955	16,955	16,955	16,955	16,955	16,955	16,955	16,955	16,955
Summary										
Total System Available Generation	67,122	69,598	71,779	71,378	71,885	71,655	67,850	66,975	67,212	65,211
Total System Capacity Requirement (PRM)	53,482	52,872	52,683	52,544	52,329	52,087	51,843	51,516	51,240	51,067
Surplus Above PRM with CAISO Modifications	13,640	16,726	19,096	18,834	19,556	19,568	16,007	15,459	15,972	14,144
Surplus Above PRM with CPUC Assumptions	16,395	19,480	22,010	21,748	22,924	22,936	19,376	18,827	19,340	17,513
Difference in Surplus between CPUC and CAISO	***2,755***	***2,755***	***2,914***	***2,914***	***3,369***	***3,369***	***3,369***	***3,369***	***3,369***	***3,369***

MPR Gas Forecast Methodology

- CPUC Scoping Memo specifies that the LTPP proceeding use a gas forecast calculated using the same methodology as the Market Price Referent (MPR) using NYMEX data gathered from 7/26/2010 – 8/24/2010
  - MPR methodology provides a transparent framework to derive a forecast of natural gas prices at the utility burner-tip in California
  - In the near term (before 2023), the forecast is based on:
    1. NYMEX contract data for natural gas prices at Henry Hub and basis point differentials between HH and CA
    2. A municipal surcharge, calculated as a percentage of the commodity cost
    3. A gas transportation cost based on the tariffs paid by electric generators

CA Gas Forecast

- 2020 natural gas forecast for CA delivery points (2010$/MMBtu)

Zone	Jan	Feb	Mar	Apr	May	Jun	Jul	Aug	Sep	Oct	Nov	Dec
Gas - PGE_Citygate	$ 5.95	$ 5.92	$ 5.75	$ 5.31	$ 5.29	$ 5.34	$ 5.41	$ 5.45	$ 5.47	$ 5.54	$ 5.79	$ 6.04
Gas - PGE_Citygate_BB	$ 6.07	$ 6.04	$ 5.87	$ 5.43	$ 5.41	$ 5.46	$ 5.53	$ 5.57	$ 5.59	$ 5.66	$ 5.92	$ 6.17
Gas - PGE_Citygate_LT	$ 6.23	$ 6.20	$ 6.03	$ 5.59	$ 5.57	$ 5.62	$ 5.69	$ 5.73	$ 5.75	$ 5.82	$ 6.08	$ 6.33
Gas - SoCal_Border	$ 5.74	$ 5.70	$ 5.54	$ 5.13	$ 5.11	$ 5.16	$ 5.23	$ 5.27	$ 5.29	$ 5.36	$ 5.58	$ 5.83
Gas - SoCal_Burnertip	$ 6.18	$ 6.15	$ 5.98	$ 5.57	$ 5.54	$ 5.60	$ 5.67	$ 5.71	$ 5.72	$ 5.80	$ 6.02	$ 6.28

CO_2 Price

- A \$36.30/short ton of CO_2 (2010\$) cost was used in the PLEXOS simulations per the CPUC scoping memo

NON-SPECIFIED ASSUMPTIONS UPDATED BY ISO

Allocation of Reserves Between ISO and Munis

- Step 1 analysis created statewide load following and regulation requirements
- Step 2 is an ISO-wide analysis that requires an allocator to split the load following and regulation requirements between the IOUs and Munis
- Allocator calculated using two parts:
  - 50% of allocator = ratio of peak load between the ISO (83%) and Munis (17%)
  - 50% of allocator = fraction of wind and solar resources delivered to California that are integrated by the ISO (94%) and Munis (6%)
- This results in the following allocation of the reserve requirements: 88.5% to the ISO and 11.5% to the Munis

Update of Generator Operating Characteristics

- ISO received feedback from 5 stakeholders on information in the 33% operational study PLEXOS database
  – Comprehensive list of changes came from SCE and included updated information on individual generator operating characteristics and SP15 hydro dispatch
  – Calpine submitted a new start profile for CCGTs
- CT planned additions and generic units were mapped to the operating characteristics of an LMS100 or LM6000 depending on plant size

Helms modeling

- PG&E updated the maximum capacity of the Helms reservoir to 184.5 GWh
- PG&E provided end of spring reservoir energy storage target and summer monthly energy usage schedules
- ISO consulted with PG&E to develop the appropriate pumping windows in 2020
  - availability in the summer months, Helms pumping was restricted to 1 pump between May and September
  - 3 pumps were assumed to be available for October through April
- Continued discussions with PG&E suggest that three pump capability in 2020 in non-summer months may not be possible; may warrant additional sensitivities

Transmission Import Limits to CA

- ISO defined simultaneous import limits to CA
- ISO used a model developed by the ISO to estimate the Southern California Import Transmission (SCIT) limit based on
  - planned thermal additions
  - OTC retirements
  - renewable resources additions
  - neighboring transmission path flows into and around the SCIT area

Import Limits by Scenario and Time

Transmission Limits (MW)	Summer Pk	Summer Off Pk	Winter Pk	Winter Off Pk
Trajectory Case				
S. Cal Import Limit to be used for study	12,416	10,709	10,928	8,823
Total California Import Limit	13,216	11,509	11,728	9,623
Environmental Case				
S. Cal Import Limit to be used for study	12,901	10,735	11,237	8,851
Total California Import Limit	13,701	11,535	12,037	9,651
Cost Case				
S. Cal Import Limit to be used for study	13,523	10,735	11,726	8,851
Total California Import Limit	14,323	11,535	12,526	9,651
Time Case				
S. Cal Import Limit to be used for study	13,221	10,735	11,499	8,851
Total California Import Limit	14,021	11,535	12,299	9,651

Assumptions of Gas Forecast Outside of CA

- The MPR methodology provides a forecast of gas prices for generators inside of California
- In order to avoid skewing the relative competitive position of gas fired generators inside and outside of California, WECC-wide gas prices outside of California must be updated to reflect the same underlying commodity cost of gas embedded in the MPR forecast

Gas Forecast Outside of CA (cont'd)

- Created an MPR-style forecast for gas prices elsewhere in the WECC drawing upon available NYMEX contract data over the same trading period (7/26/10 – 8/24/10):
  - In addition to the California gas hubs (PG&E Citygate and Socal Border), forecast hub prices at Sumas, Permian, San Juan, and Rockies hubs using the NYMEX basis differentials
  - For each bubble (geographic area), add appropriate delivery charges (based on TEPPC delivery charges) to the appropriate hub price to determine the burnertip price
- Two specific changes were made to this methodology based on IOU feedback:
  - Arizona gas hub was moved from Permian to SoCal Border
  - Delivery charge was removed from Sumas hub to British Columbia

Gas Forecast Outside of CA

- 2020 natural gas forecast for delivery points outside of California (2010$/MMBtu)

Zone	Jan	Feb	Mar	Apr	May	Jun	Jul	Aug	Sep	Oct	Nov	Dec
Gas - AECO_C	$ 5.49	$ 5.46	$ 5.29	$ 4.72	$ 4.69	$ 4.75	$ 4.82	$ 4.86	$ 4.88	$ 4.95	$ 5.34	$ 5.59
Gas - Arizona	$ 6.06	$ 6.02	$ 5.85	$ 5.42	$ 5.39	$ 5.45	$ 5.52	$ 5.57	$ 5.58	$ 5.66	$ 5.89	$ 6.16
Gas - Baja	$ 5.74	$ 5.70	$ 5.54	$ 5.13	$ 5.11	$ 5.16	$ 5.23	$ 5.27	$ 5.29	$ 5.36	$ 5.58	$ 5.83
Gas - Colorado	$ 6.08	$ 6.04	$ 5.88	$ 5.42	$ 5.39	$ 5.45	$ 5.52	$ 5.56	$ 5.57	$ 5.65	$ 5.92	$ 6.17
Gas - Idaho_Mont	$ 6.00	$ 5.97	$ 5.81	$ 5.23	$ 5.21	$ 5.26	$ 5.33	$ 5.37	$ 5.39	$ 5.46	$ 5.85	$ 6.10
Gas - Kern_River	$ 5.74	$ 5.70	$ 5.54	$ 5.13	$ 5.11	$ 5.16	$ 5.23	$ 5.27	$ 5.29	$ 5.36	$ 5.58	$ 5.83
Gas - Malin	$ 5.98	$ 5.95	$ 5.79	$ 5.10	$ 5.07	$ 5.13	$ 5.20	$ 5.24	$ 5.26	$ 5.33	$ 5.83	$ 6.08
Gas - Pacific_NW	$ 6.11	$ 6.08	$ 5.91	$ 4.98	$ 4.95	$ 5.01	$ 5.08	$ 5.12	$ 5.14	$ 5.21	$ 5.96	$ 6.21
Gas - Permian	$ 5.58	$ 5.54	$ 5.38	$ 5.01	$ 4.99	$ 5.04	$ 5.11	$ 5.15	$ 5.17	$ 5.24	$ 5.42	$ 5.67
Gas - Rocky_Mntn	$ 5.49	$ 5.46	$ 5.29	$ 4.72	$ 4.69	$ 4.75	$ 4.82	$ 4.86	$ 4.88	$ 4.95	$ 5.34	$ 5.59
Gas - San_Juan	$ 5.52	$ 5.49	$ 5.32	$ 4.86	$ 4.84	$ 4.89	$ 4.96	$ 5.00	$ 5.02	$ 5.09	$ 5.37	$ 5.62
Gas - Sierra_Pacific	$ 6.12	$ 6.08	$ 5.92	$ 5.48	$ 5.46	$ 5.51	$ 5.58	$ 5.62	$ 5.64	$ 5.71	$ 5.96	$ 6.21
Gas - Sumas	$ 6.02	$ 5.98	$ 5.82	$ 4.89	$ 4.86	$ 4.92	$ 4.99	$ 5.03	$ 5.04	$ 5.11	$ 5.86	$ 6.11
Gas - Utah	$ 5.76	$ 5.73	$ 5.56	$ 4.99	$ 4.97	$ 5.02	$ 5.09	$ 5.13	$ 5.15	$ 5.22	$ 5.61	$ 5.86
Gas - Wyoming	$ 6.05	$ 6.01	$ 5.85	$ 5.27	$ 5.25	$ 5.30	$ 5.37	$ 5.41	$ 5.43	$ 5.50	$ 5.89	$ 6.14

TEPPC PC0 Case

- PC0, a recent TEPPC database, was used to populate the PLEXOS database with loads, resources and transmission capacity for zones outside of California
- Embedded in this case were several coal plant retirements
- ISO incorporated several adjustments to this case:
  - Included several additional coal plant retirements that were announced but not included in PC0
  - Excluded the resources assumed to contribute to California's RPS portfolio that are located outside of California

Exclusion of RPS Resources from PC0

- TEPPC's PC0 case includes enough renewables to meet RPS goals in California and the rest of the WECC
  - The portfolio for California is very similar to the Trajectory Case specified for the LTPP, which includes out-of-state renewables
- To develop consistent scenarios for LTPP, the RPS builds for CA in PC0 must be adjusted according to the following framework:

	WECC-Wide RPS Resources in PC0
—	PC0 RPS Resources in CA
—	PC0 OOS RPS Resources Attributed to CA
+	CPUC RPS Portfolio (Traj/Env/Cost/Time)
=	**RPS-Compliant LTPP Scenario**

State	**Resource**	**MW**	**GWh**
New Mexico	Biomass	39	231
Idaho	Geothermal	27	198
Nevada	Geothermal	76	561
Utah	Geothermal	120	885
British Columbia	Small Hydro	90	442
Oregon	Small Hydro	13	50
Nevada	Solar Thermal	285	933
Arizona	Solar PV	319	737
Nevada	Solar PV	23	41
Alberta	Wind	1,565	4,843
Colorado	Wind	517	1,298
Montana	Wind	262	818
Oregon	Wind	871	2,373
Washington	Wind	1,252	3,004
Wyoming	Wind	86	344
Total		5,544	16,760

OOS resources to remove from PC0

Coal retirements by 2020

- PC0 includes the following coal plant retirements:
  - **AESO:** Battle Units 3 & 4 and Wabamun Unit 4 **(586 MW)**
  - **NEVP:** Reid Gardner Units 1-3 **(330 MW)**
  - **PSC:** Arapahoe Units 3 & 4 and Cameo Units 1 & 2 **(216 MW)**

- Based on conversations with Xcel and announced retirements, ISO included the following retirements:
  - Arapaho Unit 4 repowers as a natural gas combined cycle **(109 MW)**
  - Cherokee Units 1-4 retire **(722 MW)**; unit 4 repowers as a natural gas combined cycle **(351 MW)**
  - Four Corners Units 1-3 retire **(560 MW)**
  - Valmont Unit 5 retires **(178 MW)**

REFINEMENTS OF THE STATISTICAL MODEL OF OPERATIONAL REQUIREMENTS (STEP 1)

Step 1 inputs and analysis of the four scenarios results are available

- Aggregate minute and hourly profile data
- Load, wind and solar forecast error
- Monthly and daily regulation and load following requirements
- Data available at: http://www.caiso.com/23bb/23bbc01d7bd0.html

Refinements to load profiles

- Load peak demand and energy adjusted to conform to CPUC scoping memo based on 2009 CEC IEPR
- LTPP net load reduction of approximately 6,500 MW in 2020 relative to "vintage" 33% reference case due to demand side programs specified in the CPUC scoping memo
- Statewide peak load in CPUC Trajectory Case is 63,755 MW versus 70,180 MW in vintage 33% ISO Operational Study reference case

Refinements to load forecast error

- Updated load forecast error based on 2010 actual load and forecast data
- Hour ahead forecast data based on T-75 minutes in updated LTPP analysis versus T-2 hours in vintage case
- 5-minute data shows increased forecast error based on actual load data

Comparison of Load Forecast Errors

LTPP Analysis

Season	HA STD 2010 ADJUSTED For PEAK (based on 2010 data)	RT (T-7.5min) STD 10% Improve 2020 (based on 2010 data)	HA autocorr	RT Autocorr
Spring	545.18	216.05	0.61	0.86
Summer	636.03	288.03	0.7	0.92
Fall	539.69	277.38	0.65	0.9
Winter	681.86	230.96	0.54	0.85

Vintage Analysis

Season	HA STD 10% Improve 2020 (based on Vitage 2006 data)	RT (T-7.5min) STD 10% Improve 2020 (based on Vitage 2006 data)
Spring	831.11	126
Summer	1150.61	126
Fall	835.11	126
Winter	872.79	126

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Refinements to wind profiles

- Wind sites were expanded to include quantity and locations consistent with CPUC scoping memo
- For new plants, wind plant production modeling based upon NREL 10 minute data production was expanded to include 21 distinct locations in California and 22 locations throughout the rest of WECC.

Refinements to wind forecasting errors

- Recalibrated wind forecast errors using profiled data
- Applied a *t-1hr* persistence method for estimating forecast errors

Comparison of Wind Forecast Errors

Region	Case	Technology	MW	Persistent	Hour	Spring	Summer	Fall	Winter
CA	33%Base	Wind	9436	T-1	All	0.040	0.038	0.032	0.031
					Vintage Cases	0.050	0.045	0.044	0.041

Note: Actual wind forecast error based on existing PIRP resources is higher than forecast *t-1hr* based on profiles

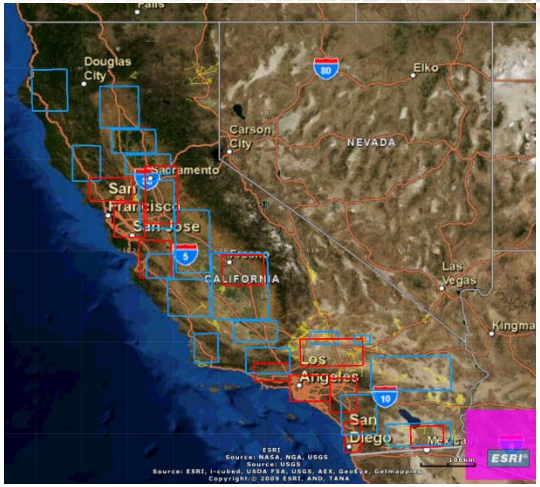
PIRP Forecast Error								
Region	Tech	MW	Persistent	Hour	Spring	Summer	Fall	Winter
CA	Wind	1005	T-2	All	11.1%	10.8%	8.1%	6.0%
CA	Wind	1005	T-1	All	8.4%	7.1%	5.3%	3.9%
CA	Wind	1005	PIRP	All	10.5%	8.9%	8.4%	6.7%

Refinements to solar profiles

- Profiles for 2010 scenarios are developed based on satellite irradiation data[1] rather than rather than NREL land based measurement data used previously.
- Variability was introduced based on a plant footprint rather than a single point
- Better represents diversity of resources
- Expanded use of 1 minute irradiance data to use three locations:
  - Sacramento Municipal Utility District (SMUD) in Sacramento
  - Loyola Marymount University in Los Angeles, and
  - in Phoenix, AZ

[1] The Solar Anywhere satellite solar irradiance data can be found at: https://www.solaranywhere.com/Public/About.aspx

Extended approach to profile small solar



- Extended method to profiling of small solar
- Define geographic boundaries of the 20 grids in Central, North, Mojave, and South area
- Choose each rectangular grid to represent an appropriate area. Each grid will have a different size rectangle
- Average the data on an hourly basis for each rectangle
- Follow similar process for developing solar profiles and adding 1-minute variability

Refinements to solar forecast errors

- Determined errors by analyzing 1-minute “clearness index” (CI) and irradiance data using *t-1hr* persistence
- To address issues that arise using the *t-1h* persistence during early and later hours of the day, use 12-16 persistence to determine solar forecast error
- Results on next slide
  - CI persistence method for Hours 12-16 similar in outcome to “improved” errors
- Recommendations:
  - Since forecast errors are based on profiles and not actual production data, recommend calibrating the simulated to the actual forecast errors when more solar data is available
  - Continue to develop forecasting error for early and later hours of the day

Comparison of solar forecast error with persistence

Comparison of Solar Forecast Errors

Region	Case	Technology	MW	Persistent	Hour	0<=CI<0.2	0.2<=CI<0.5	0.5<=CI<0.8	0.8<=CI<=1
CA	33%Base	PV	3527	T-1	Hour12-16	0.035	0.069	0.056	0.023
CA	33%Base	ST	3589	T-1	Hour12-16	0.060	0.109	0.108	0.030
CA	33%Base	DG	1045	T-1	Hour12-16	0.022	0.047	0.039	0.018
CA	33%Base	CPV	1749	T-1	Hour12-16	0.016	0.033	0.031	0.016
		All			Vintage Cases	0.05	0.1	0.075	0.05

IMPROVEMENTS TO SIMULATION EFFICIENCY

Modeling Improvements

- The model was modified to improve accuracy of modeling and efficiency of simulation while not compromising quality of results
- The major modifications implemented are:
  - Separation of spinning and non-spinning requirements
  - Generator ramp constraints for providing ancillary services and load following capacity
  - Simplified topology outside of California
  - Mixed integer optimization in California only
  - Tiered cost structure in generic resources in determining need for capacity

Separation of spinning and non-spinning requirements

- In the previous model, non-spinning includes spinning in both requirements and provision
- Spinning and non-spinning are separated in this model
  - The requirements for spinning and non-spinning are all 3% of load
  - The provision of non-spinning of a generator does not include its provision of spinning
- The separation is consistent with the ISO market definition and is needed to implement the ramp constraints as discussed below

Generator ramp constraints for providing ancillary services and load following capacity

- 60-minute constraint
  - The sum of intra-hour energy upward ramp, regulation-up, spinning, non-spinning, and load following up provisions is less than or equal to 60-minite upward ramp capability of the generator
  - The sum of intra-hour energy downward ramp, regulation-down, and load following down provisions is less than or equal to 60-minite downward ramp capability of the generator

Generator ramp constraints for providing ancillary services and load following capacity (cont.)

- 10-minute check constraint
  - The sum of upward AS and 50% of load following up provisions is less than or equal to 10-minite upward ramp capability
  - The sum of regulation-down and 50% of load following down provisions is less than or equal to 10-minite downward ramp capability

Generator ramp constraints for providing ancillary services and load following (cont.)

- 10-minute AS constraint
  - The sum of upward AS provisions is less than or equal to 10-minite upward ramp capability
  - Regulation-down provision is less than or equal to 10-minite downward ramp capability
- 20-minute constraint
  - The sum of upward AS and load following up provisions is less than or equal to 10-minite upward ramp capability
  - The sum of regulation-down and load following down provisions is less than or equal to 10-minite downward ramp capability

Simplified topology outside of California

- The topology was simplified by combining transmission areas (bubbles) outside CA according to the following rules:
  - The areas have no direct transmission connection to CA
  - The areas are combination by state or region (Pacific Northwest)
- There will be no transmission congestion within each of the combined areas

Mixed integer optimization in California only

- Model has mixed integer optimization in CA only
  - Mixed integer optimization applies to all CA generators and generators as dedicated import to CA only
  - These generators are subject to unit commitment decision in the optimization
  - Other generators outside CA are not subject to unit commitment decision
  - These generators are available for dispatch at any time (when they are not in outage)

Tiered cost structure in generic resources in determining need for capacity

- In the run to determine need for capacity, generic resources have high operation costs set up in a tired structure such that:
  – The generic resources will be used only when they are absolutely needed to avoid violation of requirements
  – The use of generic resources will be in a progressive way (fully utilizing the capacity of one generic unit before starting to use the next one)
- The model using this method can determine the need for capacity in one simulation

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Tiered cost structure in generic resources in determining need for capacity (cont.)

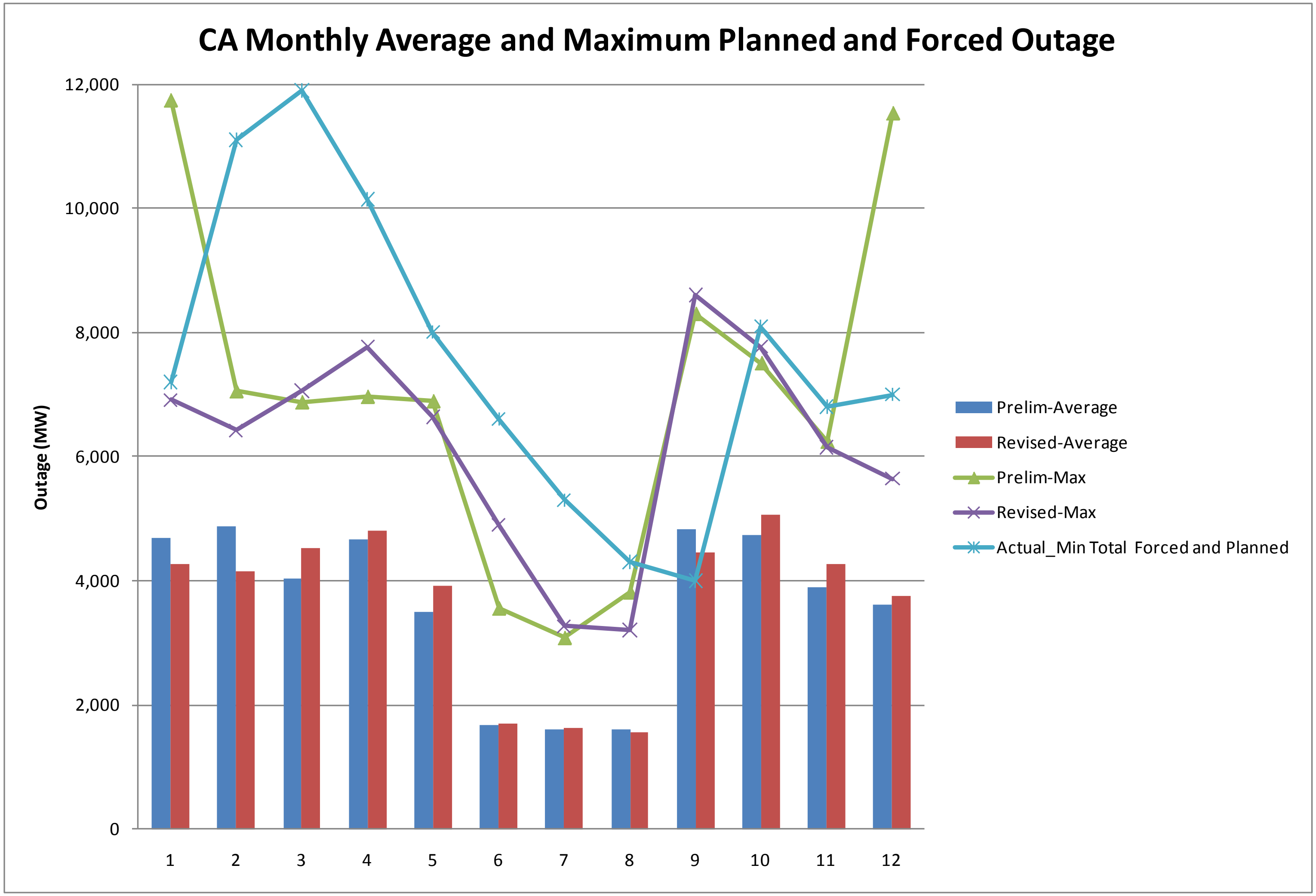
- The VOM cost and the cost to provide AS or load following of the generic resources are set up as

    Tier 1 – $10,000/MW　　Tier 2 - $15,000/MW

    Tier 3 – $20,000/MW　　Tire 4 - $25,000/MW

- In the run to determine the need for capacity startup costs of all generators are not considered for the method to work properly
- The run uses the monthly maximum regulation and load following requirements for each hour

Review of outage profile.



Note: Outage profiles need further consideration

EXHIBIT K

Docket No. 07-AFC-6

CENTER FOR BIOLOGICAL DIVERSITY'S RESPONSE IN SUPPORT OF CITY OF CARLSBAD'S MOTION TO TAKE OFFICIAL NOTICE AND THE CENTER'S MOTION TO TAKE OFFICIAL NOTICE AND RE-OPEN THE EVIDENTIARY RECORD

For Immediate Release: May 18, 2011
Media Contact: Sandy Louey - 916-654-4989

Energy Commission Licenses Two East Bay Power Plants

824 Megawatts Proposed for Local Communities

Sacramento - The California Energy Commission today approved the construction of two natural gas-fired power plants in the East Bay.

In two separate unanimous votes, the Energy Commission adopted the presiding member's proposed decisions (PMPDs) that recommended licensing the 200-megawatt Mariposa Energy Project in northeastern Alameda County and the 624-megawatt Oakley Generating Station Project in eastern Contra Costa County.

"Approving these natural gas power plants will help meet California's growing energy needs," Energy Commission Chair Dr. Robert B. Weisenmiller said. "When these facilities come online they will provide reliable power for homes and businesses all around the East Bay."

Natural gas-fired power plants facilitate the expansion of renewable energy power plants such as wind and solar because of their consistent and reliable power.

The PMPDs for the two projects said the facilities, as mitigated, will have no significant impacts on the environment and comply with all applicable laws, ordinances, regulations, and standards. The decisions were based solely on the records of the facts, which were established during the facilities' certification proceedings.

Both PMPDs determined the records, which contain detailed environmental impact assessments required by the California Environmental Quality Act, were adequate. The records for the projects include the Energy Commission staff's thorough independent assessment of the projects' potential impacts on the environment, public health, and safety.

The Mariposa Energy Project is a simple-cycle peaking facility. The project would be located about seven miles northwest of Tracy and seven miles east of Livermore. Mariposa Energy, LLC, which is owned by Diamond Generating Corporation, is the project applicant. Diamond Generating Corporation is a wholly-owned subsidiary of Mitsubishi Corporation. A peaker power plant operates only during high electricity demand.

The proposed project site is in an unincorporated area designated for agricultural use. The facility would be located southeast of the intersection of Bruns and Kelso roads on a 10-acre portion of a 158-acre parcel south of Pacific Gas & Electric Company's Bethany Compressor Station and Kelso Substation. Construction would begin this year with commercial operation by mid-2012 if there are no delays.

The Oakley Generating Station Project is being proposed by Contra Costa Generating Station, LLC, a limited liability corporation owned by Radback Energy, Inc. The proposed project is a combined-cycle electrical generating facility. The project is located on a 21.95-acre site in the city of Oakley in eastern Contra Costa County.

Construction of the plant, from site preparation to commercial operation, will occur over a 33-month period. The applicant has a purchase and sale agreement with PG&E to guarantee commercial availability of power by June 1, 2016.

# # #

EXHIBIT L

Docket No. 07-AFC-6

CENTER FOR BIOLOGICAL DIVERSITY'S RESPONSE IN SUPPORT OF CITY OF CARLSBAD'S MOTION TO TAKE OFFICIAL NOTICE AND THE CENTER'S MOTION TO TAKE OFFICIAL NOTICE AND RE-OPEN THE EVIDENTIARY RECORD

South Bay Power Plant Ceases Operations

Thursday, 06 January 2011

Contact: Barbara Moreno (619) 686-6216, John Gilmore (619) 686-7206

The South Bay Power Plant in Chula Vista ceased operations on January 1, 2011.

South Bay is an old, 309-megawatt, natural gas-fired peaking facility, that many consider an eyesore on the Chula Vista bayfront.

In October 2010, the California Independent System Operator (Cal-ISO), notified the plant's operator, Dynegy Inc. that it would rescind its decision to extend the plant as a must-run facility for 2011. Cal-ISO is a non-profit corporation that manages most of the state's power grid.

Its decision triggered the plant's closure under the company's lease contract with the Port of San Diego, which owns the facility.

Two of South Bay's four units were retired at the end of 2009 due to the expiration of must-run status for those units.

"The first South Bay unit entered production in 1960, and in the following decades, the plant consistently produced electricity in a safe and reliable manner," said David Byford, Sr. Director of Public Relations for Dynegy. "This can be attributed to a dedicated group of employees who worked diligently over the last 50+ years to produce electricity from the South Bay generation facility."

The Port District bought the power plant in 1999 with the express purpose of tearing it down and cleaning up the site whenever Cal-ISO determined that it was no longer needed.

As part of the Chula Vista Bayfront Master Plan, future land uses contemplated on the power plant site are open space, park, and a commercial recreation/RV area.

The Port anticipates that the California Environmental Quality Act, or CEQA process – a statute that requires state and local agencies to identify the significant environmental impacts of a project – will take approximately 18 months or longer to complete. Once the CEQA process has been completed, and all other permits have been obtained, there is an estimated 27 months of demolition and remediation on the property.

The cost of the demolition and cleanup is dependent upon the amount of remediation that will have to occur. Estimates have gone as high as $70 million.

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Reactions

onellsoto 01/06/2011 01:15 PM

From Twitter

As expected, South Bay Power Plant marked the start of the new year by powering down: http://bit.ly/fQEv5X

Trackback URL http://disqus.com/forum

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EXHIBIT M

Docket No. 07-AFC-6

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Update on South Bay Power Plant Removal

Friday, 20 May 2011

Contact: Marguerite Elicone (619) 686-6222

The Port of San Diego and the City of Chula Vista are working in partnership to facilitate the process of removing the South Bay Power Plant structure.

The two agencies are collaborating and have identified the appropriate permit process to take the structure down in an expedited and safe manner.

"The Port District and the City of Chula Vista are spearheading this project, but it's also a multi-agency effort," said Scott Peters, Chairman of the Board of Port Commissioners. "Although it is a process with many steps, eventually it will result in a much-improved bay front for the City of Chula Vista, with many recreational and economic opportunities."

The plant, located on the waterfront of the City of Chula Vista, is owned by the Port of San Diego and was operated by Dynegy. It ceased operating on December 31, 2010 after the California Independent System Operator deemed that its power was no longer needed. Dynegy holds the lease to the plant, which is comprised of approximately 150 acres of land and 242 acres of water.

Dynegy is currently assessing removal of asbestos and other hazardous materials from the above-ground structure. Abatement activities could take approximately 10 months and are a precursor to the demolition. The demolition permit will be issued by the City of Chula Vista.

"We are moving along and have identified what permits are necessary to remove the structure," said Commissioner Ann Moore, who represents the City of Chula Vista on the Board of Port Commissioners. "We are collaborating closely with the City of Chula Vista to ensure that we can do this expeditiously and safely."

Commissioner Moore is actively involved with the management of the project because of the keen interest of the City of Chula Vista.

In addition to the demolition permit, Dynegy will seek a Coastal Development Permit from the California Coastal Commission prior to commencing demolition of the plant's structure.

Demolition and remediation of the plant's site is a multi-agency collaboration. Along with the port and the City of Chula Vista, the California Coastal Commission, the San Diego Air Pollution Control District, Cal-OSHA, San Diego County Department of Environmental Health, the Regional Water Quality Control Board and the California Department of Fish & Game are also part of the permitting process.

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From Twitter

Update on South Bay Power Plant Removal http://j.mp/lwSjIx

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EXHIBIT N

Docket No. 07-AFC-6

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Susan Kraemer

SCE Buys 20 Years of Solar Power for Less than Natural Gas

5 comments
February 1, 2011 in Solar Energy

A milestone in solar pricing has been met in California this month, according to Vote Solar.

Southern California Edison has selected 250 MW worth of solar bids from companies able to produce solar electricity for 20 years for less money annually than the 20 year levelized cost of energy of a combined-cycle natural gas turbine power plant.

SCE's bidding process for smaller renewable projects is smart. These small projects do not face the multi-year bureaucratic delays for extensive reviews, like most utility-scale solar, so each small unit can be built as quickly as normal commercial rooftop solar projects. They are made up of multiple distributed solar installations of under 20 MW, which in combination total a power plant-sized 250 MW.

The utility already gets more than 19% of its electricity from renewable sources, placing it in the lead between California's three big utilities to reach the Renewable Energy Standard requirement to get 20% of its electricity from renewables (which excludes large hydro and nuclear) by 2013.

This year SCE had put out a request for bids to get 250 MW of just solar power, made up of multiple smaller rooftop arrays. Fremont-based Solyndra was one of the early bidders to be accepted. Solyndra will supply 20 years of power, with its unique cylindrical solar panels, to be installed by its subsidiary, Photon Solar.

With a bidding process, SCE can save money by making renewable energy companies compete to offer the lowest price for supplying the utility some of its electricity through its Renewable Standard Contract

The requirement is that the renewable energy has to be priced to cost no more than the Market Price Referent (MPR) - which is an annual calculation of the 20 year levelized cost of energy of a combined cycle gas turbine.

This year, the solar bids are below the MPR, meaning that they cost less than the annual cost of getting the same amount of electricity from natural gas over the same time period.

Even more interesting, SCE says that they received over 2.5 GW - 2,500 MW - of offers from solar companies eager and apparently able to supply solar power for less than the cost of gas. I was not able to locate that price in their detailed filing with the California Public Utilites Comission (PDF), a hefty tome. but the MPR for 2010 appears to be in the 11 cent range.

According to Adam Browning at Vote Solar, "prices are kept confidential for something like 3 years. All we know is whether it is above or below MPR—and the advice letter says it is below".

EXHIBIT O

Docket No. 07-AFC-6

CENTER FOR BIOLOGICAL DIVERSITY'S RESPONSE IN SUPPORT OF CITY OF CARLSBAD'S MOTION TO TAKE OFFICIAL NOTICE AND THE CENTER'S MOTION TO TAKE OFFICIAL NOTICE AND RE-OPEN THE EVIDENTIARY RECORD

Print

Solar PV Becoming Cheaper than Gas in California?

By Stephen Lacey, Editor | February 8, 2011

The latest round of proposed contracts from a California utility for 250 MW of solar PV projects comes in below the projected price of natural gas.

California -- We hear it every day: "Solar is too expensive." Well, not according to the California utility Southern California Edison.

In a recent filing to the state's Public Utilities Commission, SCE asked for approval of 20 solar PV projects worth 250 MW – all of which are expected to generate a total of 567 GWh of electricity for less than the price of natural gas.

Although the exact details of the 20-year contracts for the projects are kept confidential for a few years, the utility reports that all winning solar developers issued bids for contracts below the Market Price Referent, which is the estimated cost of electricity from a 500-MW combined-cycle natural gas plant.

What does that mean? It means that a large number of solar PV project developers believe they can deliver solar electricity at a very competitive price. And these aren't mega-projects either. All of the installations will be between 4.7 MW and 20 MW – a sweet spot for PV projects.

Although the price of natural gas has plummeted in recent years because of excessive production and lower demand for power, the cost of solar projects and the price of solar electricity has dropped in tandem. With stong solar requirements in states like California, demand for PV has stayed strong.

"Solar energy is a natural hedge against rising energy costs – a hedge that regulators and utilities are turning to lower electricity costs for their customers," said Rhone Resch, president and CEO of the Solar Energy Industries Association.

California regulators seem to agree that mid-sized solar PV installations, which capture economies of scale but suffer fewer regulatory and transmission constraints, are an important part of the market.

These latest projects were solicited through SCE's Renewables Standard Contracts program, a reverse auction mechanism implemented by the utility in 2010. The program is a precursor to California's Reverse Auction Mechanism (RAM) that was approved last December. That 1-GW program requires California's three largest utilities to hold auctions twice a year to solicit bids from developers of mid-sized (i.e. 1-20 MW) solar PV projects.

The 250 MW of contracts sent to the CPUC for approval is in addition to a 500-MW solar program initiated by SCE in 2009.

According to SCE's filing, the utility seems to be genuinely positive about the prospects for solar PV:

“Solar PV is a mature and proven renewable energy technology that has been supplying a substantial amount of renewable energy to SCE and other California load-serving entities (“LSEs”) for several years.”

While large-scale concentrating solar power projects have been gaining ground in California and other southwestern states, PV is looking like the better option in many cases. Due to the steady declines in the cost of production and price of modules, as well as improvements in Balance of Systems technologies (i.e. power electronics, racking and wiring) that make installations more efficient, solar PV is leading the way.

“The solar industry has done a great job in bringing down costs – long a promise, now a reality,” said Adam Browning, executive director of the Vote Solar Initiative, in a response to the recent SCE announcement. “These are price-points that can really scale, and will encourage policymakers to think big.”

In a recent report from GTM Research comparing similar-sized CSP and PV projects, the authors forecast that electricity from utility-scale PV plants will be considerably lower than some CSP technologies. In the next decade, the research firm projects CSP plants will be generating electricity in the $0.10 to $0.12 per kWh range and PV will be producing electricity in the $0.07 to $0.08 kWh range. (On the flip side, CSP technologies can offer storage capabilities and hybrid natural gas components, providing value that PV can't necessarily deliver.)

With high peak demand, lots of expensive “spinning reserve” power plants and ample sunlight, California is the likely place for PV to compete. But with project costs continuing to drop and utilities promoting the technology, the steady march toward grid parity will spread to other markets as well, said Vote Solar's Browning.

“Though California does have world-class sunlight, solar is modular and adaptable, and similar results can be had throughout the country.”

http://www.renewableenergyworld.com/rea/news/article/2011/02/solar-pv-becoming-cheaper-than-gas-in-california

EXHIBIT P

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SIGN ON SAN DIEGO

Gas from afar pollutes here, critics say

County officials concerned that use of LNG will lead to more smog in the region

By Onell R. Soto /h5>
5 p.m., Jan. 13, 2011

San Diego's air quality folks are worried that natural gas imported from overseas could erase decades of work cleaning San Diego's air.

County officials say that San Diego Gas & Electric, which operates the region's natural gas pipelines and distribution lines, is allowing the import of the extra-polluting gas and hasn't taken steps to minimize its impact.

"If you're doing something today that is increasing the emissions in the air, you have an obligation to clean that up," said County Supervisor Ron Roberts, who also serves on the state Air Resources Board.

SDG&E says the natural gas — used since October for heating, cooking and power generation in the county's homes and businesses, and in trucks and buses — meets the state's pipeline standards. The company questions the county's findings that it increases pollution in the region.

It also says it's powerless to stop the gas at the border, even though it's imported through a terminal owned by a sister company, Sempra LNG. And it says very similar gas already is being used in the region.

At issue is liquefied natural gas, also known as LNG.

It's regular natural gas, but what's in it and the process by which it is transported makes it burn hotter than the natural gas we've been using until now, said Bob Kard, who heads the San Diego County Air Pollution Control District.

Sempra LNG's plant 15 miles north of Ensenada is the first facility on the west coast of North America which can import super-cooled natural gas. 2008 file photo. — Eduardo Contreras

What's the problem?

The San Diego County Air Pollution Control District says gas from overseas increases pollution and may lead to more smog and asthma attacks. It wants San Diego Gas & Electric to take steps to limit that pollution.

What does SDG&E say about that?

SDG&E and a sister company, Sempra LNG, disagree with that conclusion. They say the district's findings are wrong, and that other studies are under way to determine the impact of the natural gas from overseas.

They say the gas meets state pipeline requirements, and it would be too expensive to make it meet the more stringent motor vehicle standards, which they call antiquated.

They also say that other natural gas used in the region, including natural gas made in California, has the same qualities that the county officials complain about.

What's next?

He calls it hot gas.

LNG is shipped by big tankers from Indonesia, Russia and Qatar. To get it on the ships, it's cooled to 260 degrees below zero Fahrenheit, until it turns into a liquid. Some of the inert gases, like nitrogen, however, don't make the trip across the ocean. And the natural gas has more of some other fuels that increase its heat content.

Once it arrives at a terminal near Ensenada called Energia Costa Azul, it's warmed back up and put into pipelines.

It's used in power plants in Mexico. It's also brought into the United States.

Last year, about 4.3 percent of the natural gas used in the region came in through that pipeline.

That meant that generally, once every 23 days or so, you cooked with that gas. It was used to make electricity. It was used to get MTS bus riders around town. It was used in factories and to heat office buildings.

The gas meets state pipeline standards but not standards for use in motor vehicles. SDG&E got an exemption to allow it to be used in buses and trucks.

The county figures that if this gas is used throughout the region, replacing traditional supplies, that would result in four to five tons a day of extra pollution, specifically smog-causing chemicals known as volatile organic compounds and nitrogen oxides.

To put that in perspective, a typical summer day in the county will bring 157 tons of nitrogen oxides and 159 tons of volatile organic compounds. Most of that comes from cars, buses and trucks.

"We get concerned when we see (additions of) a tenth of a ton," Roberts said. "I get very concerned when I see four or five."

The problem isn't how the gas is used in big, new natural-gas-fired power plants, because they have sophisticated controls to make sure they don't pollute too much and adjust for differences in the fuel they use.

It's how it works in furnaces, small power plants, stoves and older vehicles, where there isn't the possibility to adjust how it's used.

Kard and Roberts say the extra pollution will set back

County officials are upset with state officials for allowing this gas to be used in buses, trucks and cars even though it doesn't meet standards, and say they may go to the courts because that approval is a violation of state law. They also say they may go after SDG&E for allowing the import of the gas.

State officials say they didn't violate the law. SDG&E says it is powerless to stop the import of the gas if it meets state standards.

More

A discussion between SDG&E and the top county pollution control official: LNG and pollution, questions and answers

What is LNG?

Liquefied natural gas is natural gas that has been cooled to 260 degrees below zero Fahrenheit, until it condenses. It takes up 600 times less space than at room temperature.

Once cooled, the gas can be transported across the ocean on ships. At import terminals like Sempra's Energia Costa Azul LNG plant in Baja California, the gas is allowed to warm and expand and is then put into pipelines for distribution along with domestic supplies of natural gas. Once LNG is warmed up and put in pipelines, it's no longer LNG but simply natural gas.

The physics of cooling the gas removes any nitrogen, carbon dioxide and other components, which increases the energy content.

What is CNG?

Compressed natural gas is natural gas under high pressure, about 3,000 psi, which allows it to take up 1 percent of the space of uncompressed natural gas. It remains in a gaseous state, so it's not to be confused with LNG. CNG is used by vehicles like trucks, buses and cars and as a replacement for diesel or gasoline. It generates less pollution than those fuels.

What's this mean?

This all means that natural gas produced in Qatar, Russia or Indonesia can be cooled into LNG, imported into Mexico and warmed back up and put in pipelines, then compressed at a fueling station into CNG.

DOCUMENT

Download: Letter from Supervisor Ron Roberts to Air Resources Board

DOCUMENT

Download: Response from Air Resources Board to Supervisor Roberts

work the county is required to do, by law, to clear San Diego's air.

"What you're talking about is basically having a company that is directly responsible for adding a lot of additional pollutants to the air, and we're going to have to find a way to get those out," Roberts said.

That may well mean stricter controls on companies with emission permits. Those permits are issued under state and federal law to businesses that produce air pollutants, such as dry cleaners, coffee roasters, auto body shops and power plants.

LNG by the numbers

4.3% Percentage of natural gas in San Diego County that came through the Energia Costa Azul LNG plant in 2010.

118 billion cubic feet: how much natural gas was delivered to San Diego County in 2010.

400 million cubic feet a day: the capacity of the pipeline connecting San Diego to Baja California at Otay Mesa.

630 million cubic feet a day: the total capacity of SDG&E's natural gas system.

"They're basically going to cause other businesses and other entities to clear up their problem," he said.

SDG&E says the county is overstating the problem.

The study on which it's basing its estimate is wrong, and other studies are under way to determine the impact of using LNG on the region's air quality, said utility spokesman Art Larson.

The county's study, he said, was inconclusive.

"No one knows what that number is," Larson said. "We believe that Mr. Kard has no hard, factual evidence to support his estimate."

Plus, it's myopic to focus simply on LNG, said Kathleen Teora, a spokeswoman for the SDG&E sister company that operates the Baja import terminal.

"The issue of gas quality is much broader than an isolated disagreement between the local air district and Sempra LNG or any other individual entity," she said. "LNG is just one minor part of the equation."

All the natural gas delivered to SDG&E, whether from an LNG terminal or from fields in Texas, Colorado or Canada, has to meet the state's pipeline standards.

Those standards were arrived at by the California Public Utilities Commission after hearing from air pollution regulators in Los Angeles and San Diego.

"The CPUC has left the door open to take another look at these standards," she said. "If new, compelling evidence is brought forward by the (air pollution control districts), the CPUC should be willing to revisit this issue."

Spokespeople for the commission said county officials have not approached them recently. Air quality concerns were considered in 2006, when the pipeline standards were set, but the commission ultimately sided with gas companies and against pollution control officials.

As for use in motor vehicle, Larson said about 40 percent of the gas SDG&E distributes doesn't meet the state standards.

That's OK, he said, because a very small amount of gas is used that way, less than 1 percent, and because today's modern engines are better able to deal with different kinds of gas, which they use as compressed natural gas, or CNG.

And because it meets the pipeline standards, SDG&E is legally required to take it because the company is a common carrier. The gas company buys only a third of the gas that courses through its pipelines. The rest is bought by big users of natural gas, like power plants.

SDG&E didn't have the option to reject the gas and keep the CNG trucks and buses on the road.

And taking them off the road would cause big problems for riders — the majority of MTS buses run on CNG — or put diesel-powered vehicles back out there, causing even more pollution.

Because SDG&E had to take the gas, the only way to keep using it as a vehicle fuel was to get an exemption, Larson said.

The only difference between the gas that's been coming in from the LNG terminal and that which meets the state motor vehicle standards is in the amount of inert gases, he said.

Sempra LNG, SDG&E's sister company, has the ability to inject nitrogen, an inert gas, into the supply coming out of the import terminal, said Teora, the spokeswoman.

But it doesn't make economic sense to inject enough nitrogen to meet the vehicle standards set by the Air Resources Board. That's because there are only a few older vehicles on the road that can't deal with newer formulations. A better solution, she said, is to scrap the motor vehicle standard and set up a new one more in line with today's engines.

Roberts and Kard are upset that the Air Resources Board gave SDG&E the go-ahead to put the gas into buses and trucks.

They say state officials violated laws designed to protect the environment by not considering the effect of the exemption requested by SDG&E and Southern California Gas.

A few weeks ago, the head of the California Air Resources Board, Mary Nichols, responded to concerns.

Like SDG&E's Larson, she said that the alternative to granting the exemption would be to take CNG buses and trucks off the road.

She also denied there was a violation of state environmental laws, which don't apply to experimental exemptions like this one.

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EXHIBIT Q

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CENTER FOR BIOLOGICAL DIVERSITY'S RESPONSE IN SUPPORT OF CITY OF CARLSBAD'S MOTION TO TAKE OFFICIAL NOTICE AND THE CENTER'S MOTION TO TAKE OFFICIAL NOTICE AND RE-OPEN THE EVIDENTIARY RECORD

Mexico's Costa Azul re-exports first LNG cargo

Houston (Houston)--10Jan2011/646 pm EST/2346 GMT

Sempra Energy's Energia Costa Azul LNG import terminal in Baja California, Mexico, recently re-exported its first cargo under a one-time authorization from Mexican authorities, but has no plans to seek authorization to do so on a long-term basis, a Sempra spokeswoman said Monday.

Spokeswoman Kathleen Teora said she could not discuss any details of the re-export, but did say that the facility has not re-exported any other cargoes since it came online in May 2008.

An industry source said the re-export was likely part of a swap between San Diego-based Sempra and the UK's BG. The re-export was loaded at Costa Azul on January 1 on BG's 145,000 cubic meter (equivalent to 3.1 Bcf of gas) Methane Nile Eagle bound for Chile, the source said.

Meanwhile, BG's 145,000 cu m Methane Jane Elizabeth on January 6 delivered a cargo to Sempra's Cameron LNG terminal in Cameron Parish, Louisiana, the source said.

The cargo that arrived at Cameron LNG came from Egypt's Damietta liquefaction plant, the source said, while the cargo that was reloaded at Costa Azul came from Tangguh LNG.

The swap helped Sempra because it needed to import a cargo into Cameron LNG to keep its equipment there at the correct temperature, the source said.

Sempra only has a long-term LNG contract with Indonesia's Tangguh LNG to supply its Costa Azul terminal, so without the swap, it would have had to turn to the spot market for the cool-down cargo, likely at a price of $7-$8/MMBtu, the source said.

That would have been significantly higher than US Henry Hub gas prices. The NYMEX February gas futures contract closed at $4.434/MMBtu on January 6.

Instead, Sempra completed a straight swap with BG and paid the same price for the Cameron LNG cargo that it pays for the Tangguh cargoes it receives at Costa Azul, the source said, in the range of $3-$4/MMBtu.

Sempra's Tangguh contract is priced at a discount to the Southern California border gas price, Sempra officials have said, without revealing the amount of the discount.

Costa Azul is designed to serve the US Southwest and Mexican markets.

BG benefitted from the swap because it has a long-term contract to supply Chile's Quintero LNG terminal on the Pacific Coast, but only has long-term contracts with Atlantic Basin suppliers for LNG, so it typically brings Atlantic Basin LNG to Chile, the source said.

In this case, it already had a ship in the Pacific Basin, and so it saved about 20 days in shipping costs from the deal, the source added. The cargo is still on its way to Chile, the source said.

In April, Sempra LNG CEO Darcel Hulse said Costa Azul was receiving a standard-sized cargo of about 3 Bcf every 12 days, and expected it to continue doing so because Tangguh LNG had ramped up to capacity.

The volume is equivalent to half of Sempra's term contractual volumes from Tangguh LNG, since Tangguh LNG has the right to divert half the volumes to higher-paying markets. The California market could absorb the sendout rate of 250,000 Mcf/d from Costa Azul deliveries, Hulse said at the time.

--Ron Nissimov, ron_nissimov@platts.com

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