Rulemaking	12-03-014
Exhibit No.:	ISO - 17
Witness:	Mark Rothleder

Order Instituting Rulemaking to Integrate and Refine Procurement Policies and Consider Long-Term Procurement Plans.	Rulemaking 12-03-014

EXHIBIT SUPPORTING PREPARED DIRECT TESTIMONY OF MARK ROTHLEDER ON BEHALF OF THE CALIFORNIA INDEPENDENT SYSTEM OPERATOR CORPORATION

Rulemaking: 12-03-014
Exhibit No.: ISO-17
Witness:

Errata to Track I Direct Testimony of Mark Rothleder on Behalf of the California Independent System Operator Corporation

Exhibits 1 - 4

BEFORE THE PUBLIC UTILITIES COMMISSION OF THE

STATE OF CALIFORNIA

Order Instituting Rulemaking to Integrate and Refine Procurement Policies and Consider Long-Term Procurement Plans.	)))	Rulemaking 10-05-006

ERRATA TO TRACK I DIRECT TESTIMONY OF MARK ROTHLEDER ON BEHALF OF THE CALIFORNIA INDEPENDENT SYSTEM OPERATOR CORPORATION

Nancy Saracino, General Counsel
Judith B. Sanders, Senior Counsel
Beth Ann Burns, Senior Counsel
California Independent System Operator Corporation
250 Outcropping Way
Folsom, CA 95630
Tel.: (916) 608-7143
Fax: (916) 608-7222
jsanders@caiso.com
Attorneys for the CALIFORNIA INDEPENDENT SYSTEM OPERATOR CORPORATION

BEFORE THE PUBLIC UTILITIES COMMISSION OF THE STATE OF CALIFORNIA

Order Instituting Rulemaking to Integrate and Refine Procurement Policies and Consider Long-Term Procurement Plans.	Rulemaking 10-05-006 (Filed May 6, 2010)

TRACK I DIRECT TESTIMONY OF MARK ROTHLEDER ON BEHALF OF THE CALIFORNIAINDEPENDENT SYSTEM OPERATOR CORPORATION

I. BACKGROUND

Q. What is your name and by whom are you employed?

A. My name is Mark A. Rothleder and I am employed by the California Independent System Operator Corporation (ISO) as Director, Market Analysis and Development.

Q. Please describe your educational and professional background.

I am the Director of Market Analysis and Development for the ISO. Prior to this role, I was a Principle Market Developer for the ISO in the lead role in the implementation of market rules and software modifications related to the ISO's Market Redesign and Technology Upgrade ("MRTU"). Since joining the ISO over ten years ago, I have worked extensively on implementing and integrating the approved market rules for California's competitive Energy and Ancillary Services markets and the rules for Congestion Management, Real-Time Economic Dispatch, and Real-Time Market Mitigation into the operations of the ISO Balancing Authority Area ("BAA"). I also have held the position of Director of Market Operations. I am a registered Professional Electrical Engineer in the state State of

California. I hold a B.S. degree in Electrical Engineering from the California State University, Sacramento. I have taken post-graduate coursework in Power System Engineering from Santa Clara University and earned a M.S. in Information Systems from the University of Phoenix. I have co-authored technical papers on aspects of the California market design in professional journals and have frequently presented to industry forums. Prior to joining the ISO in 1997, I worked for eight years in the Electric Transmission Department of Pacific Gas & Electric Company, where my responsibilities included Operations Engineering, Transmission Planning and Substation Design.

Q. What is the purpose of your testimony?

I will describe the results of the ISO's evaluation of potential operational and resource capacity needs driven by the state of California's requirement that load serving entities (LSEs) develop 33% renewable resource portfolios by 2020. For the purposes of this testimony, I will refer to this requirement as "33% RPS" and the ISO's study of operational requirements and market impacts at 33% RPS in 2020, using its renewable integration model, as the ISO's "33% integration study."

Q. Why does the ISO conduct renewable integration studies?

A. As part of the ISO's continuing effort to understand and prepare for increasing levels of renewable integration consistent with California's energy and environmental policy objectives, the ISO performs renewable integrations studies to 1) identify operational requirements necessary to support increased variability and uncertainty in supply with increasing renewable penetration; 2) assess the expected generation fleet needed to meet simultaneously both the operational requirements for renewable energy integration and the forecasted demand for energy; and 3) identify any additional operational needs for integration of renewable resources.

The ISO released a study of grid impacts associated with a 20% RPS level in 2012 on August 31, 2010.[1] In support of this renewable integration study work, the ISO produced a technical appendix[2] that explained in detail the technical methodology. Also starting in 2010, the ISO performed some preliminary studies of operational requirements and needs to meet the 33% renewable integration objective in 2020. The 33% integration study builds on the work done in the 20% RPS analysis and was intended to accomplish the following four objectives:

- Provide information for the long-term procurement docket that could be used to identify potential planning needs, costs or other options.
- Inform other CPUC and state agency regulatory decisions.
- Inform ISO transmission planning decisions regarding the need for additional infrastructure to integrate renewable resources.
- Inform the ISO in potential energy and ancillary services market enhancements for needed renewable integration capabilities.

Q. How has the ISO participated in this proceeding?

A. The preliminary 33% integration study work was performed in coordination and support of this Long Term Procurement Plans (LTPP) proceeding using assumptions from the prior LTPP assumptions (Docket No. R. 08-02-007 and predecessor dockets). In the context of this case, in 2010 the 33% study work was primarily used to familiarize parties and gain agreement regarding the renewable integration study methodology. During the third and fourth quarters of 2010, the ISO conducted Step 1 modeling and Step 2 production simulation using 2009 vintage scenarios developed by the CPUC's Energy Division (ED) staff. The ISO described its 33% integration model at a workshop on August 24, 2010; the Step 1 modeling at a workshop on October 22, 2010; and the Step 2 results at a workshop on November 30, 2010. In addition, the ISO reviewed the Lawrence Berkeley National Lab's

---

[1] See *Integration of Renewable Resources-Operational Requirements and Generation Fleet Capability at 20% RPS* at http://www.caiso.com/2804/2804d036401f0.pdf

[2] Draft Technical Appendices for Renewable Integration Studies - Operational Requirements and Generation Fleet Capability http://www.caiso.com/282d/282d85c9391b0.pdf

(LBNL) report and responded to comments and questions submitted by parties to the proceeding following each workshop.

On December 3, 2010, the CPUC issued a scoping memo in which new assumptions and scenarios were identified. The ISO has now revised its 33% integration study consistent with the CPUC's new assumptions and scenarios identified in the scoping memo. At the same time, the ISO has incorporated other identified data updates and methodological refinements to the 33% integration study. The preliminary study results based on these new assumptions and scenarios were distributed to the parties in this proceeding on April 29, 2011 and presented at a May 10, 2011 workshop. Here I describe the updates and refinements to the input data and methodology used for the 33% integration study to produce final study results, including the changes made to the preliminary study results.

Q. Do the 33% integration study methodology and the renewable portfolio scenarios that the ISO studied and that you describe in your testimony provide sufficient information to make procurement and infrastructure decisions?

A. As I describe in detail in this testimony, the study results show the flexibility requirements to support a 33% RPS result in a range of possibilities, from no additional capacity needs to the need for substantial capacity additions depending on the scenario assumptions. For this reason, the ISO believes that the study results should only be used making least regrets procurement decisions considering the lead time needed for such development . The study work that the ISO will be performing this year may provide additional insights to the plausible range of resource needs under different assumptions, which can also inform incremental procurement decisions. For example, the ISO, along with the CPUC, the CEC and other agencies, is in the process of conducting power flow and stability studies to evaluate local area capacity needs created by once through cooling (OTC) environmental restrictions. These study results will likely impact capacity input assumptions for future renewable scenarios that the ISO intends to run and will make available in the next LTPP proceeding.

In future studies, assumption areas needing further validation are the levels of energy efficiency and demand response captured in some of the renewable portfolio scenarios because such levels may take many years to achieve. Forecast error improvements should also be considered in future study work.

Because of the uncertainty around many of the study assumptions, the ISO believes that infrastructure decisions regarding the resources needed to support renewable integration is best determined on an incremental basis over the course of several years. For now it is important that the programs needed to achieve the levels of energy efficiency and demand response load reduction assumptions must be put in place as soon as possible. As the OTC study results become available, decisions about repowering or new generation siting must be considered. At the same time, the ISO will be developing market rules and integration policies that will align the operational and environmental objectives.

Q. Please describe how your testimony is organized.

A. The ISO's April 29, 2011 preliminary results were provided in the form of a slide deck. Those results now have been updated to account for the changes in modeling assumptions described in the May 31, 2011 ALJ ruling on the joint motion for extension of time to file testimony, and the ISO has updated the slide deck accordingly. In addition, the ISO has added summary information about the additional sensitivity scenarios that were modeled to test the results of the four scenarios. The updated slides are attached as Exhibit 1 and I describe them in this testimony. In the sections that follow, I will describe the 33% integration study methodology, input assumptions and the CPUC's renewable scenarios, study results, and how these results can be interpreted.

II. MODELING THE REQUIRED CPUC RENEWABLE PORTFOLIO SCENARIOS AND OTHER CASES

Q. You stated that the ISO ran the 33% integration model using 2009 vintage renewable scenarios, and these results were presented during workshops in 2010. What was the ISO's role with respect to the updated renewable scenarios described in the December 3, 2010 Scoping Ruling?

A. The ISO 33% integration study was updated to reflect the latest scenario assumptions developed by the ED staff and described in the December 3, 2010 scoping ruling[3]. Seven scenarios were specified:

1. 33% Trajectory Base Load
2. 33% Environmentally Constrained
3. 33% Cost Constrained
4. 33% Time Constrained
5. 20% Trajectory
6. 33% Trajectory High Load
7. 33% Trajectory Low Load

The assumptions for load and renewable resources vary depending on the scenario. There are a set of assumed resources that are common to all scenarios. This common assumption is referred to as the "discounted core." The discounted core consists of projects with signed power purchase agreements and filed applications for major permits. As a general observation, the load assumed in the 2010 scenarios is lower than the 2009 vintage scenarios. The ISO studied five of the seven 2010 scenarios: 33% Trajectory Base Load, Environmentally Constrained, Cost Constrained, Time Constrained, and 33% Trajectory High Load. Of these five, the first four were prioritized by the CPUC and are referred to in this testimony as the four priority scenarios. The preliminary results from modeling and production simulation runs for the four priority scenarios were provided to the parties on April

---

3 http://www.cpuc.ca.gov/PUC/energy/Procurement/LTPP/LTPP2010/2010+LTPP+Tools+and+Spreadsheets.htm

29, 2011 and discussed at the workshop held on May 10, 2011. In addition to the five CPUC scenarios, the ISO also studied an "All Gas" scenario in support of development of metrics by the IOUs, and conducted a sensitivity analysis assuming all three Helms pumps are available year round. I discuss in this testimony the results of those studies.

Q. Please provide a general description of the five scenarios and the All Gas scenario?

A. The four priority scenarios described in the scoping memo and modeled by the ISO all have the same load assumption based on the 2009 California Energy Commission (CEC) load forecast. The priority scenarios differ with respect to the assumptions about the type and location of renewables needed to achieve 33% RPS. Of these scenarios, the Environmentally Constrained scenario relies more heavily on distributed solar (about 9000 MW), which includes small to medium sized solar photovoltaic (PV) plants selling their entire output to utilities. The Cost Constrained and Time Constrained scenarios have higher levels of out of state renewables. The fifth CPUC scenario studied, the 33% Trajectory High Load scenario, has a 10% higher load assumption than the four priority scenarios to reflect any combination of future uncertainties (*e.g.,* increased load growth and programmatic performance). The Trajectory High Load scenario also had 1,497MW of additional renewable resource versus the Trajectory Base Load scenario. Slide 5 in Exhibit 1 contains a list of the load and renewable assumptions for the five CPUC scenarios that the ISO ran. The All Gas scenario uses similar base load assumptions but does not include new renewable resources. The All Gas scenario does include existing renewables and 1750 MW of expected customer PV.

Q. How do these scenarios differ from the 2009 vintage scenarios?

A. The five CPUC scenarios assumed higher quantities of energy efficiency, behind the meter combined heat and power (CHP) and different assumptions about renewable portfolio build-out than the vintage scenarios. The increased energy efficiency and

CHP assumption reduce the peak load from the 70,180MW statewide peak in the vintage scenarios to a 63,755MW statewide peak for the 2010 scenarios. Slide 6 of Exhibit 1 compares assumptions between the two sets of scenarios.

Q. How did the ISO work with the utilities to model all the scenarios?

A. The ISO collaborated with the three investor-owned utilities (IOUs) - PG&E, SDG&E and SCE - and their consultant, Environmental Energy and Economics, Inc. (E3), through the working group. As I describe later in this testimony, the ISO conducted the Step 1 modeling and Step 2 production simulation for the five scenarios. Additionally, the ISO ran the All Gas scenario to support the cost metrics that E3 was retained to provide for the IOUs. E3 also assisted with reconciling the Step 2 model and the portfolio assumptions from the scoping memo.

Q. How did the ISO use the input assumptions in the December 3, 2010 Scoping Ruling (as modified in later rulings) to develop the database to run the renewables scenarios you described?

A. The ISO found that the input assumptions (or, at times, lack thereof) in the scoping memo fell into four general categories. Some of the assumptions could be used directly in developing the database. Other assumptions needed to be clarified with Energy Division staff in order to be consistent with the scoping memo. The third category consisted of input assumptions that were needed to successfully model and run the scenarios but were not in the scoping memo. Finally, some assumptions were simply incorrect and required revisions. For the last two categories, the ISO used its independent judgment and operational experience, supplemented by expertise from Nexant (the ISO's consultant), to develop the needed assumptions or to make the necessary changes.

Q. What was the basis for the changes made to the input assumptions?

A. Slides 36-39 set forth the changes to the assumptions in the scoping memo for accuracy.

Q. Did the ISO make additional input assumptions and clarifications?

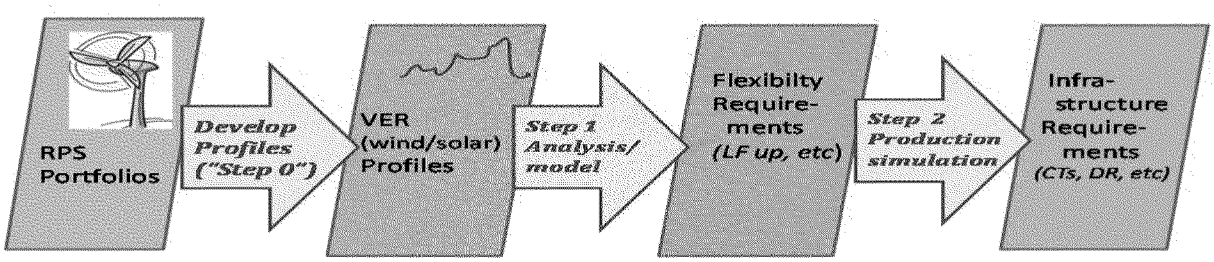
A. Yes. As I noted above, following the release of the preliminary study results on April 29, 2011, the ISO, in collaboration with the IOUs, developed a list of input assumption modifications required to finalize the studies. These assumption modifications were described in the May 31, 2011 ALJ ruling in this proceeding.

III. STUDY METHODOLOGY

Q. Can you provide an overview of the 33% integration model, and the study methodology steps followed by the ISO, to develop the results summarized in Exhibit 1?

A. Yes. The study methodology is divided into stages: Steps 0, 1 and 2, conducted by the ISO, and Step 3, undertaken by E3 and the IOUs. The first stage, Step 0, is the development of load, wind and solar profiles, based on the resource assumptions in each portfolio. The profiles are then used as inputs into the Step 1 statistical analysis to calculate regulation and load following requirements. These requirements, along with hourly load and other operating reserves, are then used as inputs to a production simulation in Step 2. Figure 1 illustrates the study process. The results of production simulation were then provided to the IOUs to develop integration metrics referred to as Step 3.

Figure 1: Renewable Integration Study Process



RPS-Renewable Portfolio Standard

VER-Variable Energy Resources

LF=Load Following

CT-Combust Turbine
DR-Demand Response

Q. What modeling tools and resources were used to conduct the study?

A. For Step 0, the ISO consulted with Nexant and used National Renewable Energy Laboratory (NREL) data and tools such as the Solar Advisory Model (SAM). To develop solar data, the ISO used 2005 Solar Anywhere satellite solar irradiance data. For the Step 1 analysis the ISO used Pacific Northwest National Laboratories' (PNNL) statistical analysis software. For Step 2, the ISO used PLEXOS Solutions production simulation package and also consulted with PLEXOS Solutions to assist in running the production simulation.

Q. How were out-of-state renewable resources considered in the study?

A. Four categories of out-of-state resources were considered: 1) 15% assumed to be import into California as a dynamic transfer, 2) 15% assumed to be import into California as a 15 minute intra-hour scheduled, 3) 40% assumed to be import into California as an hourly schedule, and 4) 30% assumed to be unbundled renewable energy credit (REC).

Q. How were the different categories of out-of-state renewable resources treated in the different steps of the study process?

A. Table 1 summarizes how the different categories were reflected in the study steps**.**

Table 1: Modeling of Out-of-State Renewable Resources

Type of Out-of-State Renewable	Step 1	Step 2	Post Processing Costs and Emissions
Dynamic Schedule/Pseudo Tie (15%)	Use 1 minute profiles as if the plant is in CA. Forecast error included.	Hourly profiled production should be modeled using import lines to carry this flow.	Zero production costs and emissions should all be attributed to CA related to imports.
15 minute intra-hour scheduled (15%)	Average 1 minute data over 15 minutes with appropriate schedule ramps. Forecast error not included.	Hourly profiled production should be modeled using import lines to carry this flow. (same as above).	Zero production costs and emissions should all be attributed to CA related to imports.
Hourly Schedule Type 2[4] (40%)	Not used in Step 1	Hourly production is modeled as if the plant's production will be injected in the bubble that the plant resides in and will have only an indirect impact on CA through any possible re-dispatch in the region the plant is located in.	Zero production costs and emissions should all be attributed to CA related to imports.
Unbundled RECs (30%)	Not used in Step 1	Hourly production is modeled as if the plant's production will be injected in the bubble that the plant resides in and will have only an indirect impact on CA through any possible re-dispatch in the region the plant is located in.	RECs should be attributed to CA. Imports would be at costs and emissions of the WECC.

[4] It is assumed that the schedule for these projects are such that the yearly production from the plant is scheduled into California without any other constraints on hourly, weekly, or monthly schedules. Within the hour balancing, and any additional balancing and shaping, is not supplied by California.

A. STEP 0 - IDENTIFYING RESOURCE CHARACTERISTICS TO BE USED IN EACH SCENARIO

Q. What is the purpose of Step 0?

A. The purpose of Step 0 profile development is to produce a series of 1 minute and hourly generation production profiles for each minute and hour of the of the year based on the resource location, quantity and a capacity factor identified in the CPUC scoping memo. The ISO has summarized the plant locations used in each CPUC scenario and capacity factors by technology in support used for this analysis at Exhibit 2 attached to this testimony. This information can also be found on the ISO website at http://www.caiso.com/23bb/23bbc01d7bd0.

Q. How did the ISO develop the Step 0 profiles?

A. As I discuss below, wind and solar 1 minute and hourly profiles were developed using different methods. In addition, the solar method was further refined to develop profiles for small-scale photovoltaic (PV), defined in the CPUC scoping memo as small distribution solar at the wholesale level. Four types of small-scale PV were specified depending on size and location: 1) large rooftop (0-2MW), 2) large ground (5-20MW), 3) mid ground (2-5MW), and 4) small ground (0-2MW). Due to the relatively small quantity and size of mid and small ground, the ISO combined the mid and small ground into the large ground profile development. The ISO modeled customer-side PV as supply in order to capture the intermittent nature of these facilities. The ISO and Nexant consulted with ED staff and E3 to clarify information provided in the scoping memo prior to developing the profiles.

Q. Please provide additional detail about how the ISO developed the Step 0 wind profiles.

A. For existing wind plant, the ISO used actual historical wind production from 2005. Aggregate data for existing wind resources is available at http://www.caiso.com/2b53/2b53c0f95d330.csv

For new wind resources, the ISO used wind generation profiles that were developed based upon NREL mesoscale wind data for 2005.[5] For new plants, wind plant production modeling was based on NREL 10 minute data production data from the year 2005 for 21 distinct locations in California and 22 distinct locations throughout the remainder of the WECC where wind plants were identified in the CPUC study scenarios.[6]

Q. What steps did the ISO take to develop profiles for new wind resources?

A. The 1 minute wind data used for all new wind plants was developed using a methodology that included the following steps or processes:

First, a representative number of plants and their geographical locations were developed, whose total capacities (MW) matched the MW in each Competitive Renewable Energy Zone (CREZ), based on the resources included in each of the scenarios developed by the CPUC. To identify the number of units and locations for the projected additions the CPUC used data from the IOU procurement processes as a starting point and generic plant information from the Renewable Energy Transmission Initiative (RETI) process and other sources. The number of plants that were ultimately used to represent the wind generation were chosen so that no one plant represented more than about 5% of the total wind generation.

[5] Data for the year 2005 was used in the ISO 33% RPS Studies because 2005 was designated as a normal hydro year. Thus load, wind, solar and hydro run of river profiles were based on conditions (wind speeds, solar irradiance, and hydro flows) that existed in 2005.
[6] NREL production data is based upon a wind farm using Vestas V-90 3 MW generators.

Second, geographic information system (GIS) software was used to find one or more appropriate NREL data sites for each CREZ to represent wind plants in that CREZ . Multiple NREL data sets within a CREZ were used to capture the diversity within a CREZ where there were multiple plants within a CREZ in the study definition. In selecting the NREL points to use from among the many NREL mesoscale points available, wind sites that represented likely sites for wind farms (ridge location, etc.) and that had capacity factors that were as close as possible to the plants specified in the scenario definitions were carefully selected.

Third, the 10 minute production data sets for the selected sites were downloaded from the NREL website. These data sets were then shifted in time to Pacific Standard Time and then the days of the week were shifted to match the days of the week for the study year – 2020. Fourth, necessary if there were any capacity factors that did not closely match the study definition plant capacity factors, the resulting data was adjusted as necessary. These adjustments were minimal since the data sets were chosen to closely match the desired capacity factors.

Fifth, the 10 minute production data for each site was curve fit with a cubic spline curve fit function to produce 1 minute data without 1 minute variability.

Sixth, a statistical model was developed using historical ISO data from several existing wind farms to capture the 1 minute variability (compared to a 10 minute average) as a function of the size of the plant/wind farm. This statistical model captures the standard deviation of the 1 minute variability as it varies with wind farm size.

Finally, using this 1 minute statistical model, variability was then added to each 1 minute splined set of data using a process that adds variability randomly as a function of the wind farm size. The final data set of 1 minute wind farm data for each plant, which includes 1 minute variability, was then used for the Step 1 statistical model to determine operational regulation and load following requirements. The hourly wind generation profiles were developed by averaging the 60 - 1 minute production data over each hour of the year.

Q. How did the ISO develop the Step 0 profiles for solar resources?

A. The solar profiles were developed based on upon satellite irradiation data. The 1 minute solar data used for all new large solar plants was developed using a methodology that includes the following steps or processes:

First, a representative number of plants and their geographical orientation were developed whose totals match the technology and number of megawatts in each CREZ[7] in the CPUC study definition. The process to identify the number of units, types, and locations for the projected additions uses as a starting point the renewable additions identified as per the renewable portfolios being modeled and assumptions about the renewable net short. Similar to wind, solar plants have a maximum size to ensure that no single profile represented more than 10% of the total solar generation to capture diversity properly.

Second, selected representative half-hourly satellite solar irradiance data points available in the 2005 Solar Anywhere solar data set were identified for each plant to be modeled. Table 2, below, shows the number of square miles of land needed by a solar plant that produces from 60-80 MWs, depending on the technology and location. Thus for a plant of 140 MWs two 1 km square areas that are adjacent to each other would be selected from the Solar Anywhere irradiance data set.

[7] Used solar CREZ info from RETI study http://www.energy.ca.gov/reti/documents/index.html

Table 2: Plant Area by Technology

Plant Technology	Area Required in Square Miles for 10 MW Facility
Solar Thermal	0.0855 Square Miles[8]
Solar PV without Tracking	0.093 Square Miles
Solar PV with Tracking	0.093 Square Miles

Third, using this information about the land area needed for specific technologies, the third step was to download the half-hourly irradiance data from the Solar Anywhere[9] website for all of the 1 square kilometer areas needed to model all of the large solar plants.

Fourth, hourly production data was developed for the plant for the appropriate technology in each CREZ using hourly average Solar Anywhere irradiation data sets for 2005 for each plant as input to the NREL SAM. The SAM model was used to develop production data for six types of technologies – Solar PV with tracking, Solar PV without tracking and Solar Thermal using a Trough, Central Tower, Central Tower with Storage, or Stirling engine.

Fifth, 1 minute production data was synthesized from the plant hourly production data using a smooth cubic spline curve fitting function. This data did not yet represent the minute to minute production variability that can be present in the output of solar plants due to clouds or other factors. What it does represent is a plant that captures the hourly variation of irradiance over its full plant footprint.

Sixth, Clear Sky profiles were developed for each plant by calculating the maximum production for each hour for each month under clear skies (without clouds, fog, or

[8] Average of solar thermal tower and trough technology.
[9] The Solar Anywhere satellite solar irradiance data can be found at: https://www.solaranywhere.com/Public/About.aspx

other factors that would reduce the amount of irradiance that falls on earth's surface).

Seventh, variability was introduced into the smoothed 1 minute plant production data using a process that inserted the variability captured from historical 1 minute irradiance data from measurements collected by NREL's Measurement and Instrumentation Data Center (MIDC)[10] at the SMUD Anatolia site in Rancho Cordova, CA, Loyola Marymount University in Los Angeles, and the SolarCAT station in Phoenix, AZ. At this stage in the process, the 1 minute data captures the variability of a plant that occupies the full plant footprint. This step is discussed in more detail below.

Eighth, to reflect the fact that certain technologies have inherent time delays in their response to changes in irradiance, the data described in step 7 was processed in an inertial delay algorithm to arrive at the final 1 minute production data. This step was applied only to solar thermal plants as it is believed that solar PV plants have negligible time delay in their response to changes in irradiance. For the three types of solar thermal technologies (trough, tower and Stirling) three different characteristics were used as shown in Figure 22.

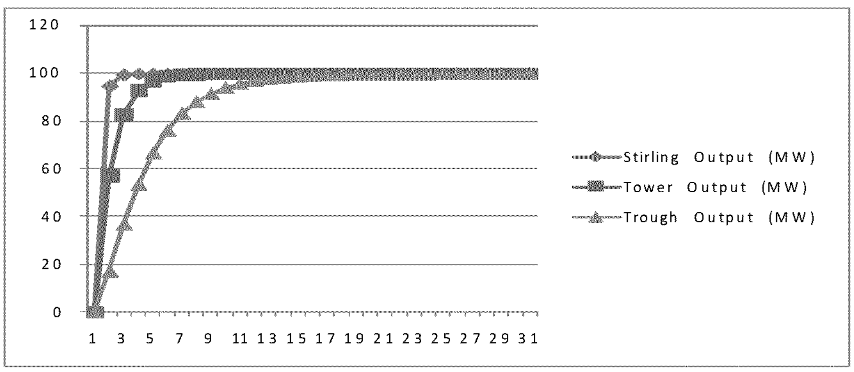


Figure 2: Response to Step Increase in Irradiance by Solar Thermal Technology v, Time in Minutes

[10] www.nrel.gov/midc

Q. Please provide additional detail about how the variability was introduced into the Step 0 solar profiles.

A. One minute variability is introduced into the smoothed 1 minute production data in Step 7 above. This step in turn is made up of several steps.

First, a Data Library was developed of 1 minute variability from historical 1 minute irradiance data collected by Sacramento Municipal Utility District (SMUD) in Sacramento, Loyola Marymount University in Los Angeles, and the SolarCAT in Phoenix, AZ. A summary plot of the raw historical irradiance data (in W/M^2) for the Sacramento sites for a single month is shown in Figure 3.

Second, this 1 minute data was converted to a normalized derate value by dividing the 1 minute actual irradiance data by the irradiance measurement that would have existed had there been no clouds in that minute (clear sky). The resulting data was a set of 1 minute historical per unit irradiance derate values that ranged from 0 to 1.0, with 0 representing full reduction from a clear sky level to a zero irradiance level and 1.0 representing no reduction from a clear sky level. Six different sets of this 1 minute derate data were developed for solar thermal and solar PV for the various sizes of plants (number of 1 kilometer squares in the plants footprint). A moving average was applied to each of the libraries, based on the number of 1km irradiance grids, to represent the 1 minute variability over the full footprint of the plant. Thus six libraries are developed for use in the subsequent steps.

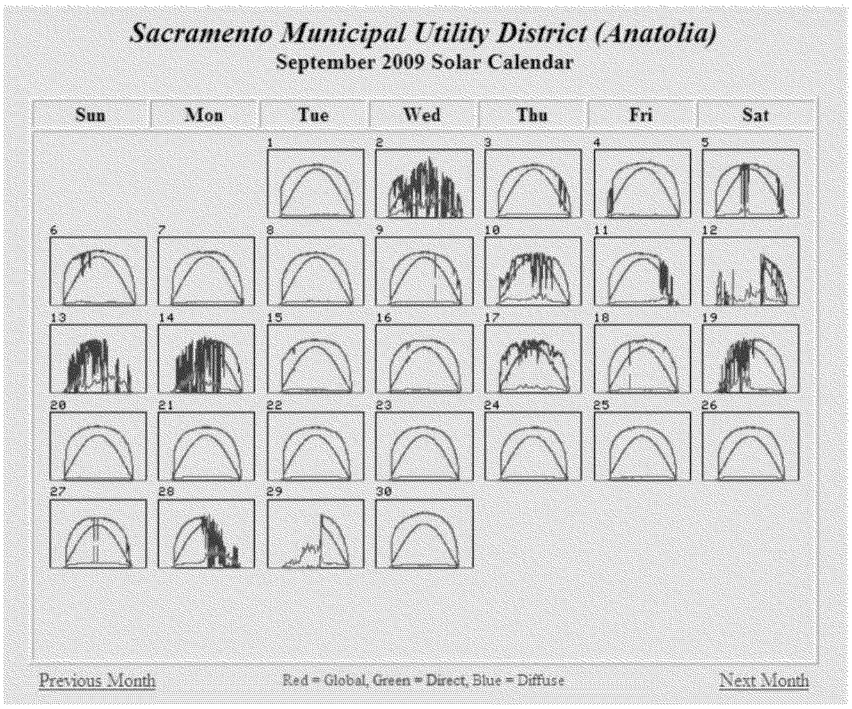


Figure 3: SMUD 1 Minute Irradiance Data for September 2009

The data plotted in the diagrams in Figure 3demonstrates that some days have little variability and other days have significant variability. Figure 4 shows the variability of a single day.

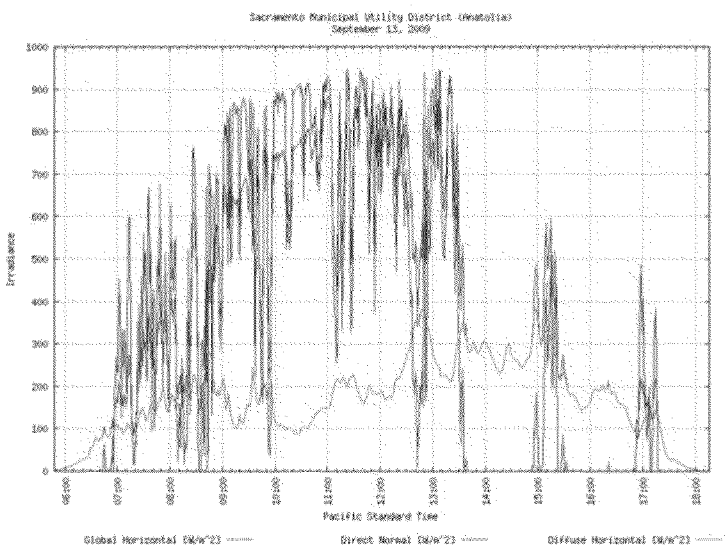


Figure 4: 1 Minute Irradiance for September 13, 2009

To capture the fact that some hours are cloudless and other hours have clouds which reduce the irradiance below its clear or cloudless sky level, variability was added to only those hours of production which show cloud cover impacts. The process first converted the 1 minute smoothed production data for the plant into 1 minute derate values that ranged from 0 to 1.0 similar to the 1 minute derate values in the irradiance data library discussed earlier. This was accomplished by dividing the smoothed 1 minute generation by the 1 minute generation that would have been produced if there were no clouds in that minute (clear sky).

Next, average production derate values were calculated on an hourly basis from the 1 minute derate values. Then for each hour of the year that had a derate value lower than 0.95, the 1 minute production derate values were replaced by an hour of irradiance derate values from the library developed that had the same hourly derate value. Which of the six libraries was used for this substitution depended on the plant size (number of 1 Kilometer squares in the plant footprint). This step added variability based upon historical data to the 1 minute production derate values while maintaining the average derate over the hour at the same level as in the production data.

Q. Did the ISO validate the variability results before finalizing the solar profiles?

Yes, we performed the following checks:

- To ensure that there were no significant step changes caused by the derate data substitution, the start minute and end minute derate values were tested to make sure they were within 1% of the minute before and the minute after the starting and ending minutes, respectively.

- To ensure that historical data was as representative as possible, substitution data was required to come from hours in the library that were within +/- 2 hours. For example, afternoon variability would not be applied to morning hours.

- To increase the number of library "hours" available for substitution, sets of 60 1 minute values (library hours) were created by shifting the start of the 60 minute period by 1 minute. For example, data from 2 hours could be used to construct 60 library hours.

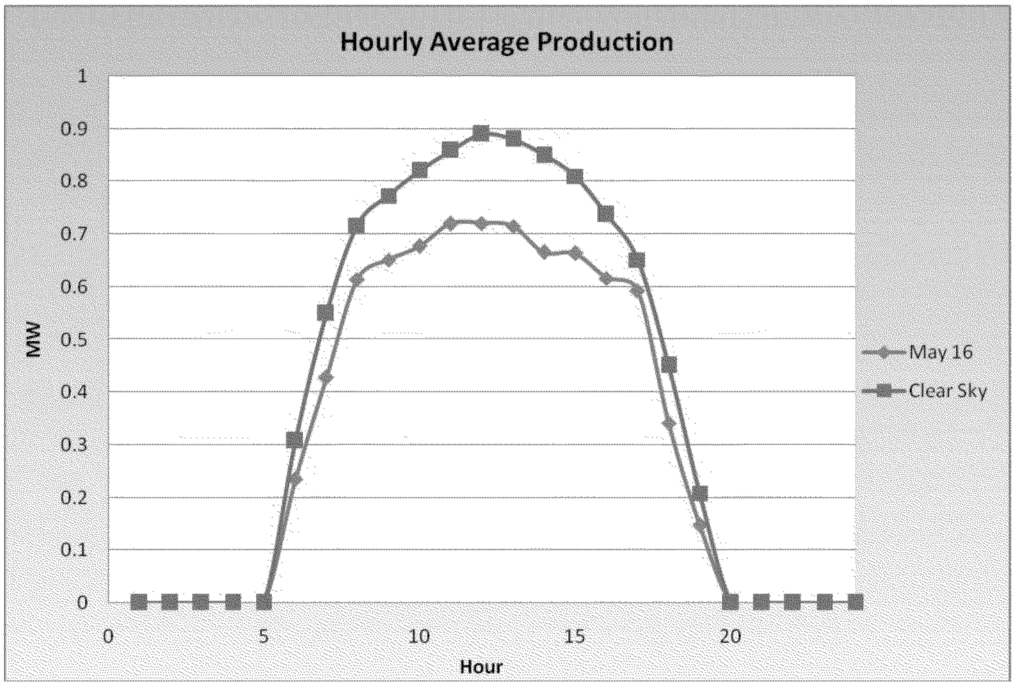
- To ensure that a bias was not introduced in the substitution process, a random selection process was used to find the derate data that met the end effects tolerances. This hourly process proceeded through the entire year to develop a full year of 1 minute production derate values.

Q. What was the final step in developing the variability results?

A. The final step converted the derate values into 1 minute production values by multiplying the derate values by the 1 minute production expected from a plant under clear sky conditions.

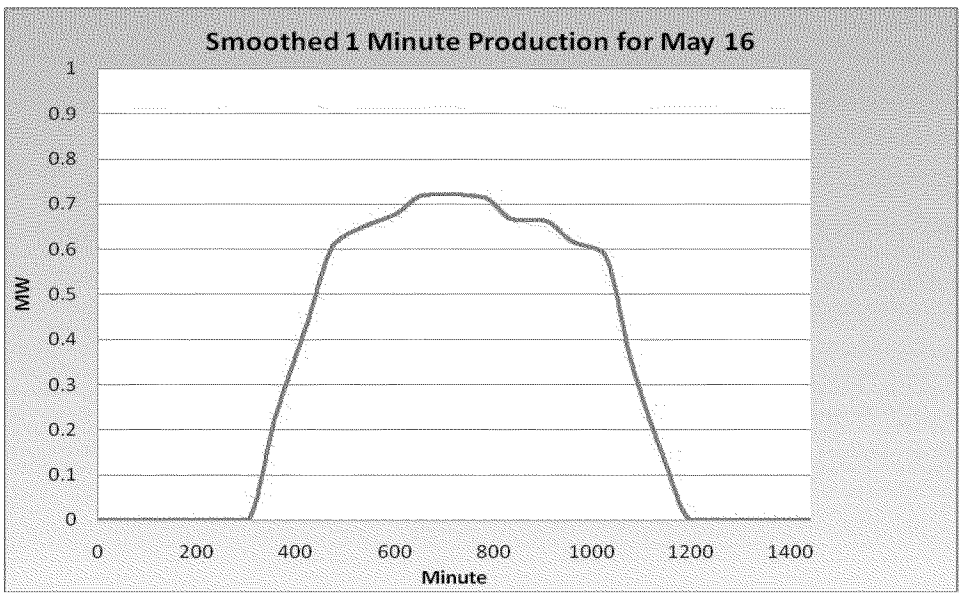
Q. Can you provide an example of the results of the variability process?

A. Yes. The results of this process are shown graphically in the figures below. Figure 5 shows the hourly production data output of the SAM for May 16, 2020. Figure 6 shows the smoothed 1 minute production data and Figure 7 shows the production data after historical variability has been added.



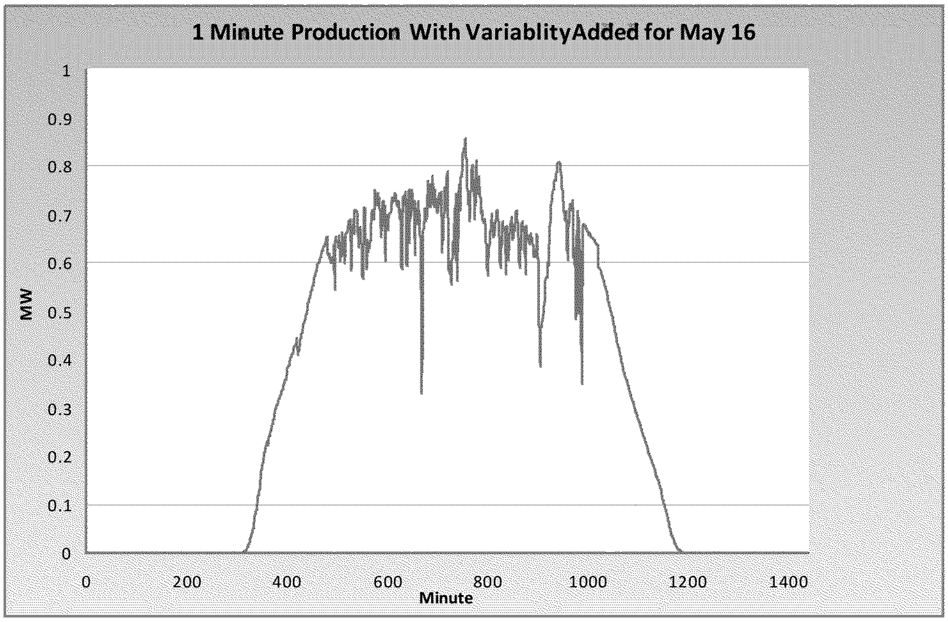
1 Minute Smoothed Production Data for a Tracking PV in the Mountain Pass/Tehachapi for May 16, 2020

Figure 5: Hourly Production Data Output from SAM Model



1 Minute Smoothed Production Data for a Tracking PV in the Mountain Pass/Tehachapi for May 16, 2020

Figure 6: Hourly Production Data Output from the SAM After Spline Fit



1 Minute Production Data With Historical Variability Added for a Tracking PV in the Mountain Pass/Tehachapi for May 16, 2020

Figure 7: Hourly Production Data Output from the SAM After Variability Is Added

Q. How did the ISO develop the Step 0 profiles for small solar PV?

A. Developing profiles for small solar PV resources presented a challenge. There are approximately 9000 MW of various types of small solar PV in the Environmentally Constrained Scenario and either 1000 MW or 2000 MW in the other scenarios. In addition, there are approximately 2000 MW of small PV on the customer side of the meter in all scenarios. The number of these plants is in the thousands, which precludes these plants from being analyzed or modeled on an individual plant basis. In addition, because of data confidentiality limitations, the supply side projects are not easily located geographically.

Q. What was the ISO's approach to modeling the small solar profiles?

A. Due to numbers, geographic and size diversity, and other factors, we decided to model these projects at an aggregate level.

For the supply side, we defined a number of rectangular geographical areas as shown in Table 3 below to cover about 4-500 MWs of generation in each rectangle. (The use of a predetermined shape allowed more efficient coding and data processing).

The numbers in the column labeled "Number of Sites" is not the actual number of sites, which are in the thousands, but the number of projects selected from RPS Calculator, each of which would be distributed over many sites. The first five columns of the Table contain clarifying information provided to Nexant by ED staff as the profiles were being developed. The last two columns, "grids" and "MWs/ grid," were developed by Nexant as part of their modeling effort.

Table 3: Small Supply Solar Projects as Defined by the CPUC

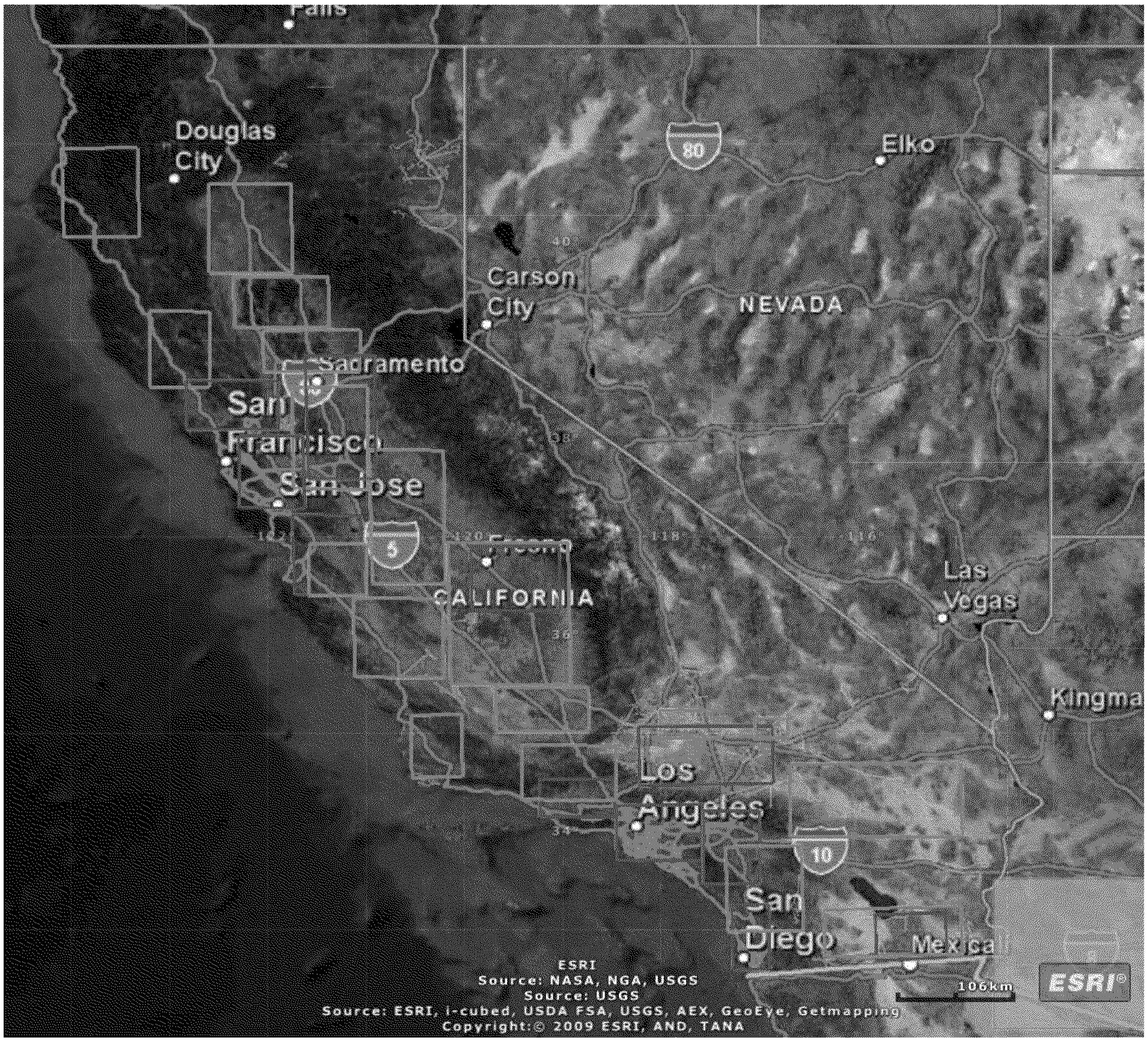
Location	Sub-Type	Number of Sites	Total MW	Capacity Factor	Grids	MWs/Grid
Central Valley	Large Ground	52	2677.7	23.56%	6	446
	Large Roof	7	710	20.37%	2	355
	Mid Ground	22	132.9	23.56%		Combine
	Small Ground	21	26.1	25.57%		Combine
Mojave	Large Ground	46	836.1	26.68%	2	418
	Large Roof	19	513.7	22.68%	1	514
	Mid Ground	21	12.5	26.68%		Combine
	Small Ground	21	3	29.36%		Combine
North Coast	Large Ground	31	725.2	21.87%	2	363
	Large Roof	19	929.9	19.56%	2	465
	Mid Ground	15	48.4	21.87%		Combine
	Small Ground	14	13.1	23.71%		Combine
South Coast	Large Ground	27	923.1	24.34%	2	462
	Large Roof	24	1517.7	21.17%	3	506
	Mid Ground	14	6.7	24.34%		Combine
	Small Ground	14	1.1	26.09%		Combine
Total		367	9077.2	Total	20	

For each square grid, we assumed that the plants are uniformly distributed over the grid. For the categories (rows) with relatively small amounts of generation, we decided that accuracy would not suffer if they were combined with other categories that had similar technologies and capacity factors. For example, under Central Valley there is 133 MW of Mid Ground and 26 MW of Small Ground. We determined that for modeling purposes these projects should be added to others in the same region with the same or similar characteristics.

Q. How were the grids distributed geographically?

Figure 8 shows the grids that are used for the 9000 MWs of solar PV.

Figure 8: Distributed Solar Geographic Areas



In this geographic representation, blue squares are for large ground projects and red squares are for large roof projects.

Q. Once the geographic boundaries were determined, what process did you follow to develop the profiles?

We selected 25 1 km by 1 km satellite irradiance data that was evenly distributed over the grid. For some grids this might be one every 5 km and others might be one every 20 km. That data was averaged on an hourly basis for each rectangle.

Next, we processed the averaged irradiance data in the SAM to develop hourly production for the MWs represented by the group. Using a cubic spline curve fit function on the hourly production, we then developed 1 minute profiles for each geographic area, which has no 1 minute variability.

We added 1 minute variability to the 1 minute production data using algorithms similar to those described above used for developing large solar plant profiles and, as the final step, we developed clear sky production for each geographic area in the same manner as with the large solar – by selecting the maximum production in each hour for each month.

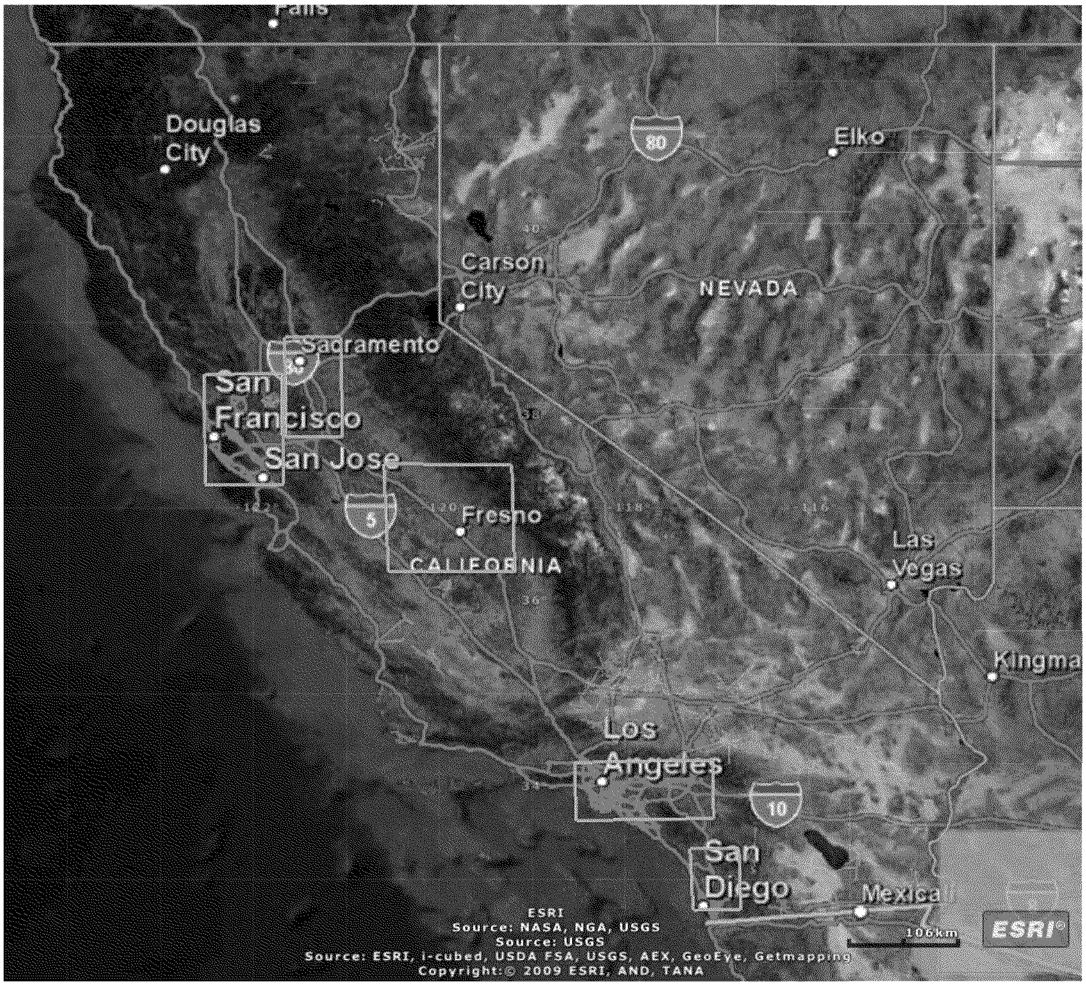
Q. What was the process used for developing small customer-side PV?

A. The process for small PV on the customer side of the meter was similar to the process used for small supply PV plants. Five grids were used, as presented on Figure 9. Table 4 provides the location, size and capacity factor planning assumptions for these customer side solar resources.

Table 4: Aggregated Customer Side Distributed Solar

Location	Profile Name	Size MW	Type	Capacity Factor
Central Valley	Distributed_Solar_1	349.9	fixed tilt	21.00%
Central Valley	Distributed_Solar_2	349.9	fixed tilt	21.00%
North Coast	Distributed_Solar_3	349.9	fixed tilt	21.00%
South Coast	Distributed_Solar_4	349.9	fixed tilt	21.00%
South Coast	Distributed_Solar_5	349.9	fixed tilt	21.00%

Figure 9: Customer Side PV Geographic Areas



Q. How were the 1-minute and hourly load profiles developed?

A. The 1-minute load profiles were developed from actual 1-2005 actual load data. The total system load was scaled up to match the hourly peak load in the CPUC defined scenarios. The 1-minute hourly data was then averaged over 60-minutes to produce an hourly load profile. The hourly load profiles were further adjusted to ensure the total energy over the year was consistent with the CPUC planning assumptions.

These load profiles were posted to the ISO website as the ISO conducted its Step 0 modeling: 1-minute load http://www.caiso.com/2b3e/2b3ed83725ee0.csv and hourly load: http://www.caiso.com/2b41/2b41d086444a0.zip.

B. STEP 1- MODELING LOAD FOLLOWING AND REGULATION REQUIREMENTS

Q. How did the ISO develop the Step 1 load following and statistical regulation requirements?

A. The Step 1 load following and regulation requirements were developed from the load, wind and solar 1 minute profiles developed in Step 0 along with distributions of load, wind and solar forecast errors. This step in the study uses a stochastic process developed by the ISO and PNNL that employs Monte Carlo simulation, a sampling over multiple trials or iterations used 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. A summary of the regulation and load following requirements produced by Step 1 analysis is provided on Slides 3 and 4 of Exhibit 1. The detailed Step 1 hourly results for the following scenarios are available at:

Scenario	Step 1 Results
Trajectory	http://www.caiso.com/2b49/2b4980da2f1e0.xls
Environmentally Constrained	http://www.caiso.com/2b49/2b49906560a70.xls
Cost Constrained	http://www.caiso.com/2b49/2b4980da2f1e0.xls
Time Constrained	http://www.caiso.com/2b4c/2b4c96c04f880.xls
Trajectory High Load	http://www.caiso.com/2b59/2b59ed4521ce0.xls

Q. Are the load, wind and solar forecast errors inputs into the Step 1 stochastic modeling process you described above?

A. Yes. As I describe below, the ISO developed distributions of forecast errors that are defined by the standard deviation and correlation of error from time interval to the next based on actual forecast and load data for load and based on a T-1 persistence method using the wind and solar profiles developed in Step 0.

Q. What are forecast errors and why is this data important to the Step 1 determination of grid operating characteristics?

A. Forecast errors quantify the magnitude of uncertainty one can expect when forecasting load or generation production from variable resources such as wind and solar resources. To ensure the ISO can balance supply and demand in real-time, the ISO must consider the difference between supply and demand that can arise in case actual conditions differ from forecasted conditions.

Q. Did you observe differences in the level of forecast errors between the 2009 vintage scenarios and the priority scenarios?

A. Yes. These differences are depicted on Slide 59 of Exhibit 1. For the load forecasts, we observed a significant reduction in hour ahead load forecast error. This reduction is because our forecast is now based on forecasts that are produced 75 minutes prior to actual operating hour. The load forecast errors in the vintage scenarios were based on load forecast that was produced 2 hours prior the operating hour. In addition, the ISO has made improvements to its load forecasting tools.

However, the 5 minute ahead forecast errors have increased some from prior analysis. The 5-minute ahead forecast errors affect regulation more than load following requirements.

The wind forecast errors determined using the T-1 persistence method discussed above resulted in modest reduction in forecast when compared the wind forecast error used in vintage scenarios. However, the forecast errors observed in the T-1 persistence method have the level observed when compared to current Participating Intermittent Resource Program (PIRP) resource wind forecast errors.

Depending the technology and clear sky index, the solar forecast errors are in some cases lower and other cases higher than the forecast errors used in the 2009 vintage scenarios.

Q. **How did the changes in forecast errors affect the Step 1 regulation and load following requirements?**

A. The lower hour ahead and wind forecast errors contributed to a reduction in the load following requirements observed in these priority scenarios when compared to the vintage scenarios results. Only modest reductions in regulation requirements were observed in part due to the offsetting effects of the high 5 minute load forecast errors.

Q. How were the load forecast errors determined?

A. The load forecast errors were determined for two different timeframes, the hour ahead and each 5-minute interval within the operating hour. For each timeframe, the forecast errors were calculated by taking the difference between the forecast demand for that timeframe and the actual average demand for the corresponding timeframe. Four probability density functions were approximated using a truncated normal distribution that is defined by using the mean and standard deviation for the forecast errors for each season. The hour ahead and 5-minute aggregated load forecast errors were calculated using actual and forecast data for 2010.

Q. What were the load forecast errors that were calculated?

A. The hour-ahead and 5-minute load forecast errors determined are presented on Slide 59 of Exhibit 1.

Q. How were the wind forecast errors determined?

A. The hour ahead wind forecast errors are based on a T-1 persistence analysis.

Q. What is T-1 persistence analysis?

A. T-1 persistence analysis compares the average production for an hour "t" with the actual production from the previous hour "T-1 hour." The basis for this approach is that a forecasting approach should be able to at least be no worse than an assumption that what is produced in one hour will persist and reflect what is produced the next hour.

Q. Why was a 1 hour comparison used?

A. 1 hour is used because currently the market structure and scheduling timelines in the west require occurring on an hourly basis and are determined approximately 1 hour ahead of the actual operating hour.

Q. What were the wind forecast errors that were calculated using the T-1 hour persistence method?

A. The hour-ahead wind forecast errors we determined are presented on Slide 61 of Exhibit 1.

Q. How were the solar forecast errors determined?

A. The solar forecast errors were determined based on a T-1 persistence analysis of the clearness index for hours 12 though 16, separately for different solar technologies- PV, solar thermal, distributed solar and customer side PV- using the profiles developed in Step 0, and broken down into 4 different clearness index categories.

Q. Why were the solar forecast errors separated into the technology and clearness index groupings you described above?

A. The solar forecast error analysis was separated due to different solar technology production patterns and variability as a function of solar irradiance. As a result, separating the forecast error analysis by solar technology and clearness index allows the ISO to better reflect the impacts of the relative quantity of different solar technology.

Q. Why was the solar forecast error analysis limited to hours 12-16?

A. The forecast error analysis was limited to hours 12-16 to avoid introducing errors that result from sunrise and sunset which would distort T-1 persistence error analysis. Hours 12-16 are hours where the clear sky solar irradiance is relatively stable from one hour to the next and better reflects forecast conditions.

Q. Did the methodology for developing forecast error consider dispatch or thermal inertial capabilities of solar thermal resources?

A. No. In the analysis of solar forecast errors conducted so far, the ISO recognized that there is further research needed to refine the impact on forecasting modeling of plant-scale effects, operational properties and performance characteristics and capabilities of different solar technologies, including startup-up in the morning and shutdown-down during the evening hours.

Q. Did you consult with others to develop the application of T-1 persistence forecast error analysis method?

A. Yes, this method was developed in collaboration with Andrew Mills, Principle Research Associate with LBNL, who provided consultation services to ED staff.

Q. What were the solar forecast errors that were calculated using the T-1 hour persistence method?

A. The hour-ahead solar forecast errors determined are presented on Slide 65 of Exhibit 1.

Q. Please provide additional details about how the Step 1 modeling process was used to calculate operational requirements.

A. A detailed description of the statistical analysis methodology is found in the technical appendix to the ISO's 20% RPS integration study that I discussed earlier in my testimony. 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. 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 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 forecast errors are modeled explicitly because of the more extreme morning and evening ramp periods for solar in 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.[11]

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).

C. <u>STEP 2 - USING PRODUCTION SIMULATION TO EVALUATE THE NETWORK AND DETERMINE OPERATIONAL NEEDS</u>

Q. Please describe how the Step 2 production simulation analysis is used to determine grid needs.

A. Step 2 production simulation is an hourly deterministic production simulation of the WECC, including California hourly dispatch with the objective of minimizing cost while meeting the hourly load, spinning reserves, non-spinning reserves, regulation requirements and load following requirements, subject to resource and inter-regional transmission constraints. The regulation and load following requirements are determined in the Step 1 analysis. If the production simulation is not able to meet one or more of these requirements, a shortfall is identified and generic resource capacity is introduced to resolve the shortfall. The generic resource additions are identified as "needs" because additional resource capacity was needed to meet the simultaneous requirements. A more detailed description of the production

[11] 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.

simulation and its formulation can be found in Section D of the Integration of Renewable Resources: Technical Appendix for California ISO Renewable Integration Studies[12]

Q. What model was used in the production simulation?

A. The Step 2 underlying model is a Plexos Solutions representation of the WECC Transmission Expansion Planning Policy Committee (TEPPC) model version PC0 dated March 21, 2011.

Q. Was this TEPPC PC0 model modified in any way to support these studies?

A. Yes, the California portion of the model had to be reconciled and modified to comply with the assumptions for the renewable scenarios described in the December 3, 2010 scoping memo.

Q. What specific modifications to the TEPPC model were made to comply with the scoping memo?

A. The load pattern in California was modified to reflect assumptions in the scoping memo including accounting for energy efficiency and demand response. Supply resources and patterns were modified to reflect the renewable resource build out as well as planned retirement additions specified in scoping memo including expected retirements of once through cooled (OTC) resources. The maximum import capability into California was modified to reflect expected condition. The natural gas prices in California were modified to reflect Market Price Referent (MPR) method specified in the CPUC scoping memo. The natural gas prices used in California can be found on slide 42 of Exhibit 1. CO2 price assumptions were used. The details of these changes can be found at slides 32-43 of Exhibit 1.

[12] http://www.caiso.com/282d/282d85c9391b0.pdf

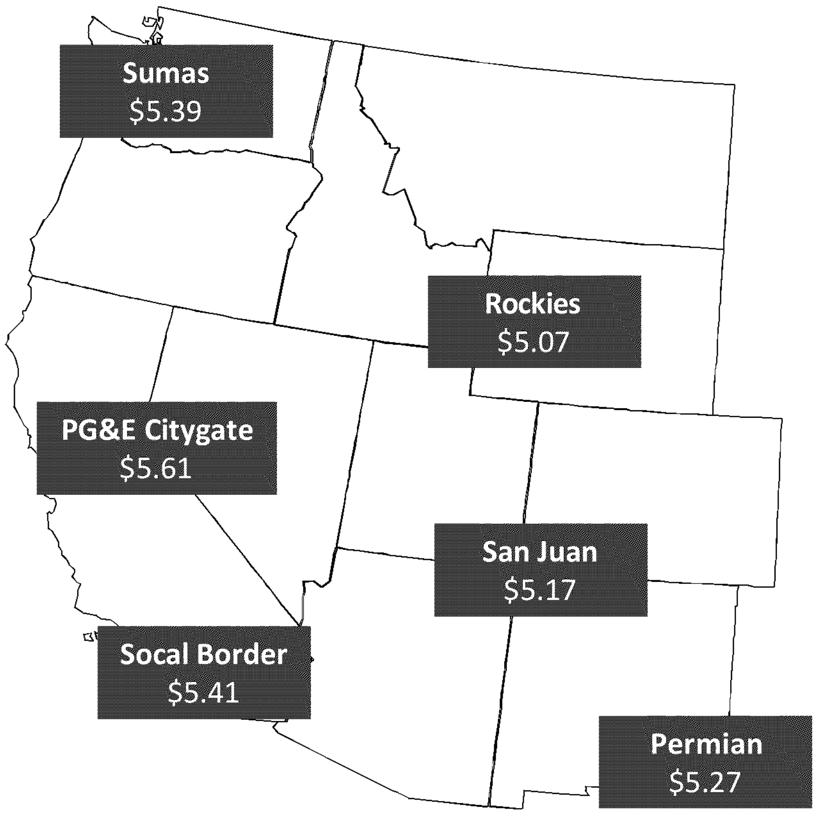
Q. Were there any other modification made to the model that were not specified in the CPUC LTPP scoping memo?

A. Yes. The allocation of regulation and load following reserves were distributed between ISO and municipal load. Generator operating characteristics, profiles and outage profiles were updated to reflect ISOs operational experience. Southern California Import Transmission (SCIT) and Path 26 interface limits were modified. Gas prices outside of California were updated to utilize a similar methodology used to develop the California gas prices. Coal resource assumptions, including planned retirements outside of California, were updated to reflect publicly available information about planned retirements. Details of these changes can be found at Slides 45-55 of Exhibit 1.

Q. Do you have any more detail regarding how the gas prices outside of California were developed?

A. Yes, the ISO found it necessary to extend the MPR methodology to develop natural gas prices for generators located outside of California. While the TEPPC PC0 case does have pre-loaded fuel prices for all generators, it was important to ensure that the natural gas prices used outside of California were consistent with those used inside of California in order to avoid introducing bias into the model's dispatch calculations. E3 assisted the ISO in developing these natural gas prices by obtaining basis spread prices from the New York Mercantile Exchange (NYMEX) for pricing points outside of California that are contemporaneous with the Henry Hub natural gas prices and basis spread prices used for California pricing points. The basis spread prices represent locational price differences between Henry Hub, Louisiana (the delivery location for the benchmark NYMEX natural gas futures contracts) and local market pricing points throughout the West: Sumas, Permian, San Juan, and Rockies. These basis spread prices are established through bilateral trading of basis "swaps," which are then cleared through the NYMEX Clearport clearing system. Figure 10, below, shows the wholesale natural gas prices derived using this methodology.

Figure 10: 2020 Average Wholesale Natural Gas Prices for Major Western Pricing Points (2010 Dollars per MMBtu, based on a Henry Hub price of $5.61/MMBtu)



E3 then applied the natural gas delivery charges from the TEPPC PC0 case, with two modifications to better reflect actual market conditions: (1) eliminated the TEPPC delivery charge for natural gas in British Columbia, and (2) established SoCal Border instead of Permian as the reference pricing point for Arizona. The table below shows the delivery charges applied in 2020.

Table 5: Natural Gas Delivery Charges in 2020 (2010 $/MMBtu)

Generator Location	Natural Gas Hub	Natural Gas Delivery Point	Delivery Charge (2010 $/MMBtu)
AESO	Rockies	AECO_C	-
APS	SoCal Border	Arizona	0.303
AVA	Sumas	Pacific_NW	0.094
BCTC	Sumas	Sumas	-
BPA	Sumas	Pacific_NW	0.094
CFE	SoCal Border	Baja	-
EPE	San Juan	San_Juan	-
IID	SoCal Border	SoCal_BurnerTip	0. 438
LDWP	SoCal Border	SoCal_Border	-
LDWP	SoCal Border	SoCal_BurnerTip	0.438
NEVP	SoCal Border	SoCal_Border	-
NWMT	Rockies	Idaho_Mont	0.512
PACE_UT	Rockies	Utah	0.271
PACW	Sumas	Pacific_NW	0.094
PG&E_BAY	PG&E Citygate	PGE_Citygate BB	0.069
PG&E_BAY	PG&E Citygate	PGE_Citygate LT	0.230
PG&E_VLY	SoCal Border	Kern_River	0.359
PG&E_VLY	PG&E Citygate	PGE_Citygate BB	0.069
PG&E_VLY	PG&E Citygate	PGE_Citygate LT	0.230
PG&E_VLY	SoCal Border	SoCal_BurnerTip	0.359
PGN	Sumas	Pacific_NW	0.094
PNM	San Juan	San_Juan	-
PSC	Rockies	Colorado	0.553
PSE	Sumas	Pacific_NW	0.094
SCE	SoCal Border	SoCal_BurnerTip	0.438
SDGE	SoCal Border	Baja	-
SDGE	SoCal Border	SoCal_BurnerTip	0.438
SMUD	PG&E Citygate	PGE_Citygate BB	0.069
SMUD	PG&E Citygate	PGE_Citygate LT	0.230
SPP	PG&E Citygate	Sierra_Pacific	0.167
SRP	SoCal Border	Arizona	0.303
TEP	SoCal Border	Arizona	0.303
TIDC	PG&E Citygate	PGE_Citygate LT	0.281
TREAS VLY	Rockies	Idaho_Mont	0.512
UT S	Rockies	Utah	0.271
WACM	Rockies	Wyoming	0.553
WALC	SoCal Border	SoCal_Border	-

In addition to the delivery charges, electric generators must pay state or local taxes in some areas. The following table lists these additional charges applied for the ISO's Step 2 analysis.

Table 6: Additional Natural Gas Costs (2010 $/MMBtu)

Natural Gas Delivery Point	Charge	Description
Arizona	5.6%	State excise tax
SoCal_BurnerTip	1.5%	Municipal Surcharge
PGE_Citygate BB	0.9%	Municipal Surcharge
PGE_Citygate LT	0.9%	Municipal Surcharge

The Natural Gas Prices in 2020 (2010 $/MMBtu) for locations external to California locations can be found on slide 52 of Exhibit 1.

Q. Were there any other modifications made to the model after the presentation of the preliminary results at the workshop May 10, 2011?

A. Yes. As I have previously described, certain proposed changes to the model were the basis for the ISO and IOU motion for extension of time to submit testimony and were described in the May 31, 2011 ALJ ruling. Details of these changes are presented in Slides 77-80 of Exhibit 1.

Q. Were there any production simulation methodology improvements incorporated into running these scenarios?

A. Yes. Based on what the ISO learned from running the 2009 vintage scenarios, the ISO worked with Plexos to develop improvements to the production simulation methodology to enhance performance. These improvements are presented in Slides 67-75 of Exhibit 1.

Q. How was the production simulation run used to produce results?

A. The production simulation was conducted for an 8760 hour/year long run using hourly time step intervals. The production simulation was first run to determine any shortfalls and incremental resource needs to resolve identified shortfalls. This run is referred to as the "need" run. For this "need" run, monthly maximum requirements for regulation and load following were used for each hour to ensure that the fleet had sufficient capability to meet a wide range of expected conditions for each month. After the "need" run was completed, a second production simulation run was performed to determine production costs, annual fuel burn, emissions and capacity factors. This second run is referred to as a "cost" run. For the "cost" run, the hourly regulation and load following requirements were used to better reflect the expected knowledge of requirements based on operational conditions.

Q. What was the ISO's involvement in Step 3?

A. The ISO provided the production simulation results to E3, who was consulting for the IOUs to perform the Step 3 metrics. The ISO did not independently perform or review the Step 3 metric analysis. As a working group member, E3 also performed reconciliation of the model and the resource planning assumptions, as well as developing the gas prices described above in my testimony. Because E3 produced its work product as part of the working group, the ISO had an opportunity to review the results and verify the reasonableness of the data before adopting it into the ISO's studies.

Q. Was the same load profile and distribution methodology used for the four priority scenarios?

A. Yes. For the peak demand calculation, Nexant consulted with ED staff and developed load profiles, based on the Statewide Net Peak Demand (70,964 MW) from Form 1.4[13] of the CEC's 2009 IEPR. Exhibit 3 attached to my testimony sets forth the load profile energy and demand assumptions and adjustments made to the Form 1.4 peak quantities:

[13] Form 1.4, Second Edition, http://www.energy.ca.gov/2009publications/CEC-200-2009-012/adopted_forecast_forms/Chap1Stateforms-Adopted-09.xls
Statewide Revised Demand Forecast Forms

- 1,131 MW of upward adjustment were made to account for behind the meter PV that was modeled as supply.
- 7005MW of downward adjustment was made to account for incremental energy efficiency.
- 1008MW of downward adjustment were made to account for behind the meter CHP.
- 327MW of downward adjustment was made to account for demand side programs.

Q. How was the load distributed in the model?

A. For the four priority scenarios, the load (hourly demand) was distributed on a pro-rata basis to the eight bubbles using allocation factors based, in part, on the energy data set forth on Exhibit 4 to this testimony. Exhibit 4 contains a set of data developed by the CEC which contains annual peak energy and demand data for each of the eight bubbles modeled in California. The peak energy values for each bubble were used after an adjustment for the customer side PV energy to calculate allocation factors for each of the eight bubbles used in the production simulation analysis. These allocation factors were then used to allocate the hourly California demand to the eight bubbles modeled. The customer side PV energy adjustment was made by allocating 52% of the total customer side PV energy to the Northern California bubbles and 48% to the Southern California bubbles based upon CEC historical data.

Q. Was the same load profile and distribution methodology used for the All Gas scenario?

A. No. For the All Gas scenario, the non-coincident peak demand for each bubble from Form 1.5b[14] was used. The total state wide, non-coincident peak demand in Form 1.5b is 70,799 MW. The load was adjusted to account for energy efficiency, CHP, demand response and customer side PV, using the same adjustments contained in Exhibit 3. Using this approach for the All Gas scenario resulted in a slightly lower total statewide load of 166MW versus the total load in the four CPUC priority scenarios discussed in the previous question.

Q. How was the Helms Pumps storage facility modeled?

A. The model contains the following assumptions about the Helms pumps:

- There are three pumps that can operate simultaneously from January to May and from October to December. There will be only one pump available for the rest of year 2020.
- PG&E provided the following pump and usage targets. The storage should reach reservoir maximum volume at the end of May.

Pump/Usage Target	Jan	Feb	Mar	Apr	May	Jun	Jul	Aug	Sep	Oct	Nov	Dec
Pump (GWh)				30.2	29.9							
Usage (GWh)						13.5	18.0	18.0	10.6			

- Based on that, the monthly initial and end storage volumes are set as follows:

Reservoir Storage	Jan	Feb	Mar	Apr	May	Jun	Jul	Aug	Sep	Oct	Nov	Dec
Initial Volume (GWh)	120	120	120	124	154	184	171	153	135	124	120	120
End Volume (GWh)	120	120	124	154	184	171	153	135	124	120	120	120

[14] Form 1.5b, Second Edition, http://www.energy.ca.gov/2009publications/CEC-200-2009-012/adopted_forecast_forms/Chap1Stateforms-Adopted-09.xls

Q. What was the basis for restricting Helms pumps in the scenarios?

A. Based on ISO transmission planning studies and planned transmission upgrades for 2020, the ISO determined that the Helms pumping window would be restricted to one pump due to the load level in the Fresno area.

IV. STUDY RESULTS

Q. Please describe the 33% integration study results for the four priority scenarios.

A. No upward incremental shortfalls were identified for the four priority scenarios, and, thus, no incremental needs of resources beyond capacity already planned were identified in any of these scenarios. However, the results show 506MW and 539MW shortfalls in downward load-following capacity in the Trajectory and Environmentally Constrained scenarios, respectively. No downward load-following shortfalls were observed in the Cost and Time Constrained scenarios. No regulation shortfalls were observed in any of the four priority scenarios. Slides 10 and 11 of Exhibit 1 provide additional details about these observations.

Q. Do you anticipate any resource needs resulting from the observed shortfalls in downward load following capacity?

A. No, not necessarily for these particular scenarios. Based on the magnitude and frequency of the observed shortfalls, storage or curtailment opportunities should be considered in lieu of additional capacity.

Q. Were any shortfalls or needs identified in the All Gas or Trajectory High Load scenarios that the ISO ran?

A. Yes. We observed 1400MW capacity need in the All Gas scenario and 4600MW capacity need in the High Load Trajectory scenario to resolve shortfalls in upward ancillary service and load following. No downward load following shortfall was observed in the All Gas. Downward load following shortfalls up to 856MW were observed in the Trajectory High Load scenario. Slides 10 and 11 of Exhibit 1 contain additional details about these observations.

Q. Can you explain why shortfalls are observed in the All Gas scenario and Trajectory High Load scenarios?

A. In the All Gas scenario, all new renewable resources were removed (except for 1750MW of customer side solar) while no additional resources were added from the base scenario. Due to the removal of such capacity, the flexible fleet capacity is being used to meet the load and does not remain available to meet the load following and regulation upward requirements. What this indicates is that qualified capacity in excess of the planning reserve margin in the four priority scenarios provides sufficient unloaded flexible capacity to meet the load following and regulation needs while the renewable resource capacity is meeting the load. In the All Gas scenario the planning reserve margin is significantly reduced while still maintaining the required planning reserve margin. In the Trajectory High Load scenario, the load was increased by 10% over Trajectory Base Load scenario. At these high load levels the flexible fleet capacity needs to produce energy to meet the load during higher load periods. As a result, remaining flexible capacity is insufficient to simultaneously meet the load following requirements.

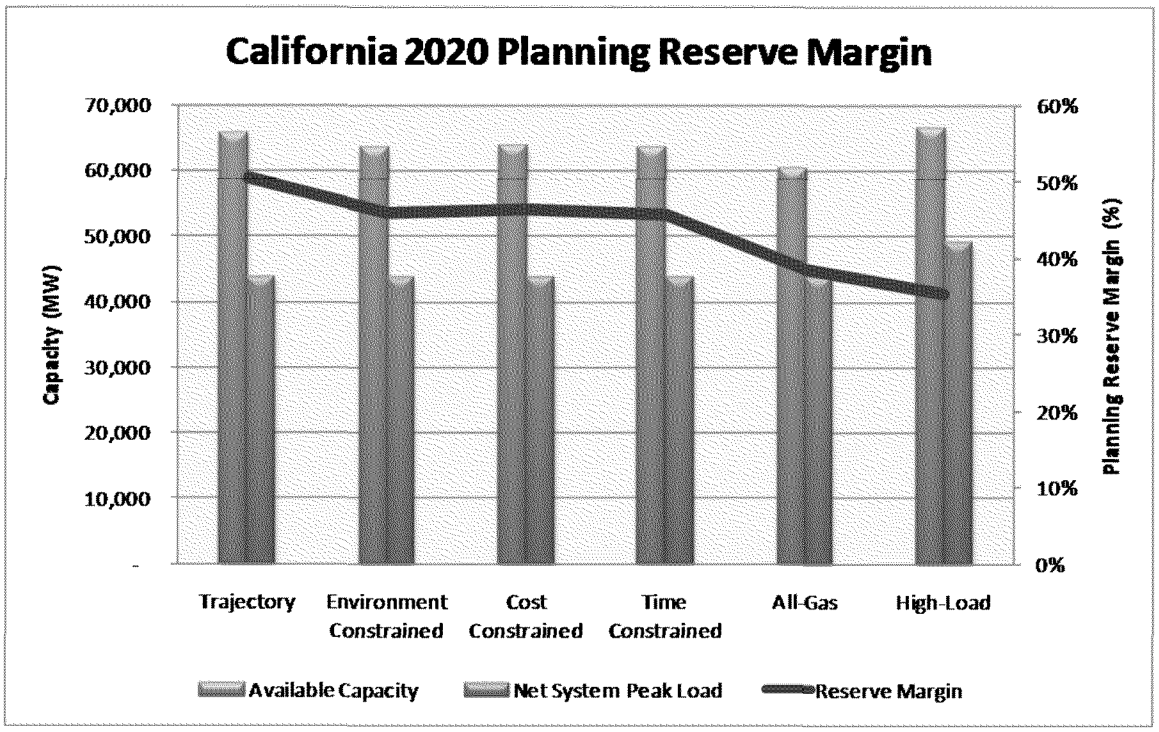
Q. Can you conclude from the four priority scenarios that no needs above planning reserve margin exist to meet renewable integration?

A. No. The four priority scenarios reflect scenarios with resource capacity in excess of the required planning reserve margin (PRM) of 15%-17%. Table 7 and Figure 11, below, show the planning reserve margin of the different scenarios as calculated by E3. As a result, the excess capacity above PRM provides sufficient flexible capacity to meet the simultaneous energy, operating reserve, regulation and load following requirements of these four scenarios. However, we cannot conclude from these results whether sufficient flexible capability would exist to meet the simultaneous energy, operating reserve, regulation and load following requirements if the available generation capacity was not in excess of the 15-17% PRM. For example, if the utilities contract for less import qualifying capacity, just meeting their PRM of 117%, the ISO may need to dispatch the capacity that is currently unloaded and providing flexibility services in these cases, and therefore may be short the needed flexible capacity. The four priority scenarios were not analyzed assuming the PRM would just be met but not exceeded.

Table 7: Planning Reserve Margin Calculated by E3

	Trajectory -Base Load	Environmentally Constrained	Cost Constrained	Time Constrained	All Gas	Trajectory -High Load
Planning Reserve Margin	51%	46%	46%	46%	39%	35%

Figure 11: Planning Reserve Margin



Q. Do the results of the Trajectory High Load scenario reflect a realistic bookend?

A. Not necessarily. As stated in the scoping memo, while the Trajectory High Load scenario may be more reflective of any combination of future uncertainties, such as increased load growth or programmatic performance, the scenario also does not account for the possible local capacity resources that may be needed due to retiring OTC resources and therefore may reflect an overly conservative supply scenario. Once the ISO's OTC studies are completed, it may be appropriate to consider repowering or scenarios that consider local capacity resources to assess what if any needs may exist in a higher load scenario.

Q. How did the total WECC-wide production cost compare among the scenarios?

A. The total production cost of the four priority scenarios are all within 0.3% of each other, with WECC wide production costs ranging from $18.85 billion for Environmentally Constrained scenario to $18.89 billion for the Cost Constrained scenario. The production costs to meet WECC load in the All Gas scenario were $ 20.79 billion. The production costs to meet WECC load in the Trajectory High Load scenario were $19.63 billion. This information can be found on Slide 14 of Exhibit 1.

Q. How did the production costs to meet California load compare among the scenarios?

A. The total production costs to meet the California load of the four priority scenarios were within 4% of each other. The Time Constrained scenario had the highest costs to meet California load ($7.45 billion), while the Environmentally Constrained scenario had the lowest cost to meet California load ($7.17 billion). The production costs to meet California load in the All Gas scenario were $8.37 billion. The production costs to meet California load in the Trajectory High Load scenario were $8.07 billion. This information can be found on Slide 18 of Exhibit 1.

Q. How did the total WECC-wide fuel usage compare among the scenarios?

A. The total WECC fuel usage for the four priority scenarios ranged from 5.366 billion MMBtu in the Time Constrained scenario to 5.375 billion MMBtu in the Environmentally Constrained scenario. The total WECC fuel usage in the All Gas scenario was 5.810billion MMBtu. The total WECC emission in the Trajectory High Load scenario was 5.544billion MMBtu. This information can be found on Slide 19 of Exhibit 1.

Q. How did the California fuel usage compare among the scenarios?

A. The total California fuel usage for the four priority scenarios ranged from 1.326 billion MMBtu in the Environmentally Constrained scenario to 1.341 billion MMBtu in the Time Constrained scenario. The total California fuel usage in the All Gas scenario was 1.417 billion MMBtu. The total WECC emission in the Trajectory High Load scenario was 1.437billion MMBtu. This information can be found on Slide 20 of Exhibit 1.

Q. How did the total WECC-wide emissions compare among the scenarios?

A. The total WECC emissions for the four priority scenarios ranged from 364,684 million metric tons at a cost of $13.238 billion in the Time Constrained scenario to 366,059 million metric tons at a cost of $13.287 billion in the Environmentally Constrained scenario. The total WECC emission in the All Gas scenario was 398,089 million metric tons at a cost of $14.450 billion. The total WECC emission in the Trajectory High Load scenario was 377,070 at a cost of $13.687 billion. This information can be found on Slides 21 and 22 of Exhibit 1.

Q. How did the emissions attributable to meet California load compare among the scenarios?

A. The Environmentally Constrained scenario reflects the lowest emissions of 76,101 million metric tons while the Time Constrained scenario had the highest among the four priority scenarios of 80,987 million metric tons. The Trajectory High Load scenario had 85,822 million metric tons attributable to meet California load. The all gas scenario has a 92,299 million metric tons meet California load. This information can be found on Slide 24 of Exhibit 1.

Q. How did the California net import compare between the scenarios?

A. The maximum imports between the four priority scenarios had similar maximum California net import of approximately 12,000MW. The Cost and Time Constrained scenarios had the highest average net imports due the higher imports renewable capacity. Slide 17 of Exhibit 1 provides a comparison of California average net import for the different scenarios.

Q. Did the Step 2 results provide any insight into start-ups and capacity factors of the fleet?

A. A higher average number of annual starts on California gas turbines of approximately 80-100 starts/year are observed versus 40-55 starts/year observed for the WECC. A lower average number of starts on California combined cycle resources of 40 starts/year versus 70-80 starts/year observed for the WECC. The capacity factor of WECC coal resources is approximately 60% in the scenarios. The capacity factor for combined cycle resources in California and WECC are both in the range of 40%. The capacity factor for gas turbines in California are approximately 6.4% versus 8% for WECC. Slides 25 and 26 of Exhibit 1 provide a comparison of start-up and capacity factors for California and WECC for the different scenarios.

Q. Were there any sensitivity runs performed assuming Helms could pump with 3 pumps year round?

A. Yes. As I discussed earlier in my testimony, the ISO performed a sensitivity run on the Trajectory Base Load scenario assuming Helms could pump with 3 pumps year round. The total annual production costs to meet California load was reduced by $2.3 million when Helms was not restricted. However, additional scenarios and benefit considerations are needed to fully evaluate the incremental benefit of having greater access to Helms pumping capabilities.

Q. How will these sensitivity results be used by the ISO?

A. These results, plus additional simulations and benefit analyses, will be provided to ISO transmission planning engineers for consideration in the 2011/2012 planning cycle.

V. NEXT STEPS

Q. Will the ISO continue to work on the 33% integration study?

A. Yes. The ISO recognizes that these 33% integration studies are based on a set of planning assumptions that will continue to evolve. The ISO intends to run additional scenarios and sensitivities that are relevant to the ISO's operational responsibilities. For example, as I discussed above, the ISO believes it is operationally relevant to consider a case with local capacity resources needed to meet local reliability needs to offset the retirement of OTC resources, once the ISO completes the OTC studies. In addition, the ISO expects to perform assessments of the resource adequacy fleet to assess whether the capacity and characteristics of the current resource adequacy fleet will be adequate to meet the changing flexibility needs of the system. Importantly, this resource adequacy assessment will consider only the generation under resource adequacy contract in order to capture the potential reality that generation capacity not under a resource adequacy contract will not be available due to lack of sufficient revenues. As the ISO completes these and potentially other operational scenarios, the ISO will make the results available and can provide updates in the next LTPP case.

Q. Does this conclude your testimony?

A. Yes, it does.

Exhibit 1

2010 CPUC LTPP Docket No. R.10-05-006

California ISO
Shaping a Renewed Future

Exhibit 1– 2010 CPUC LTPP Docket No. R.10-05-006

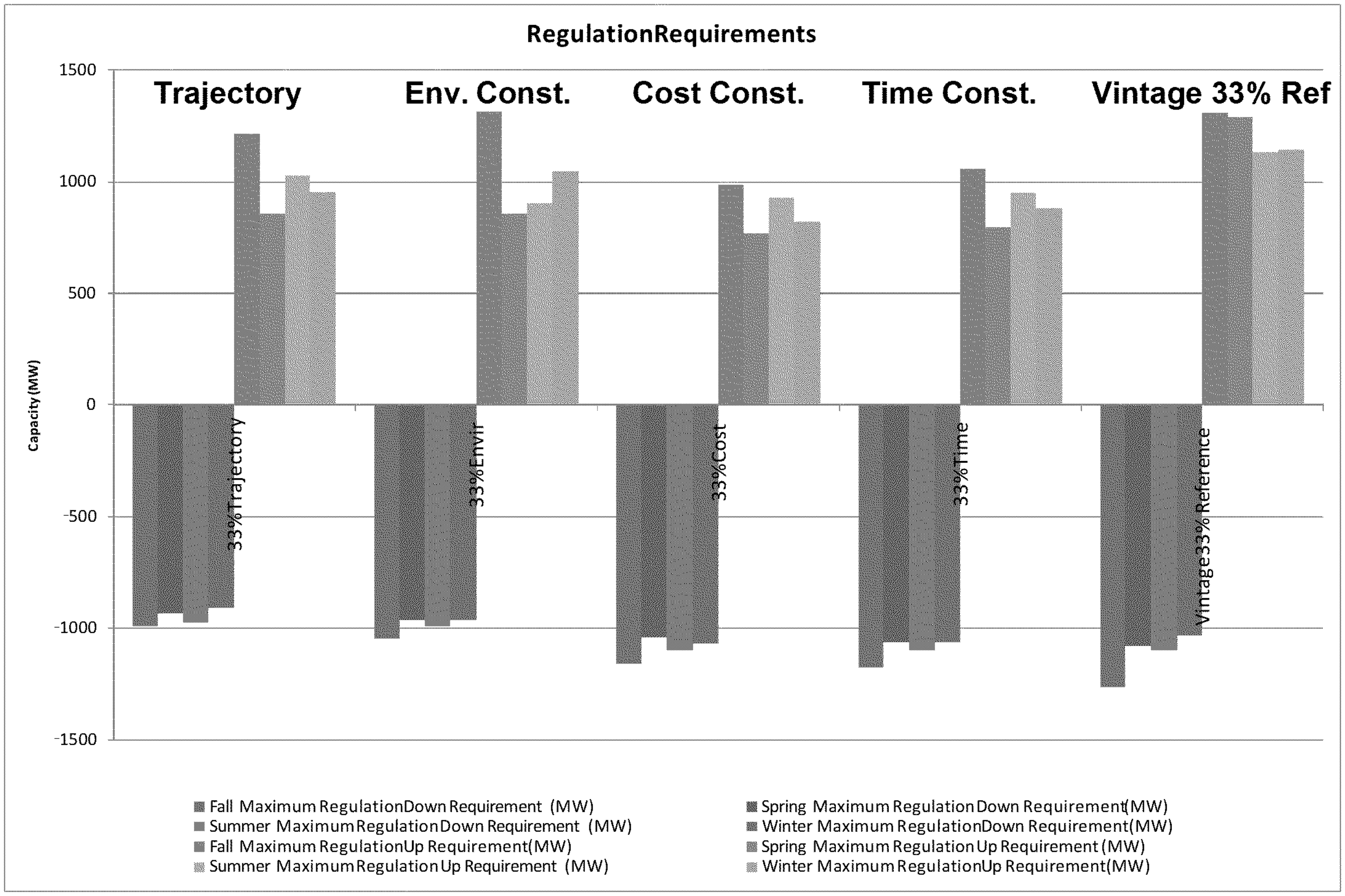
July 1, 2011

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

California ISO
Shaping a Renewed Future

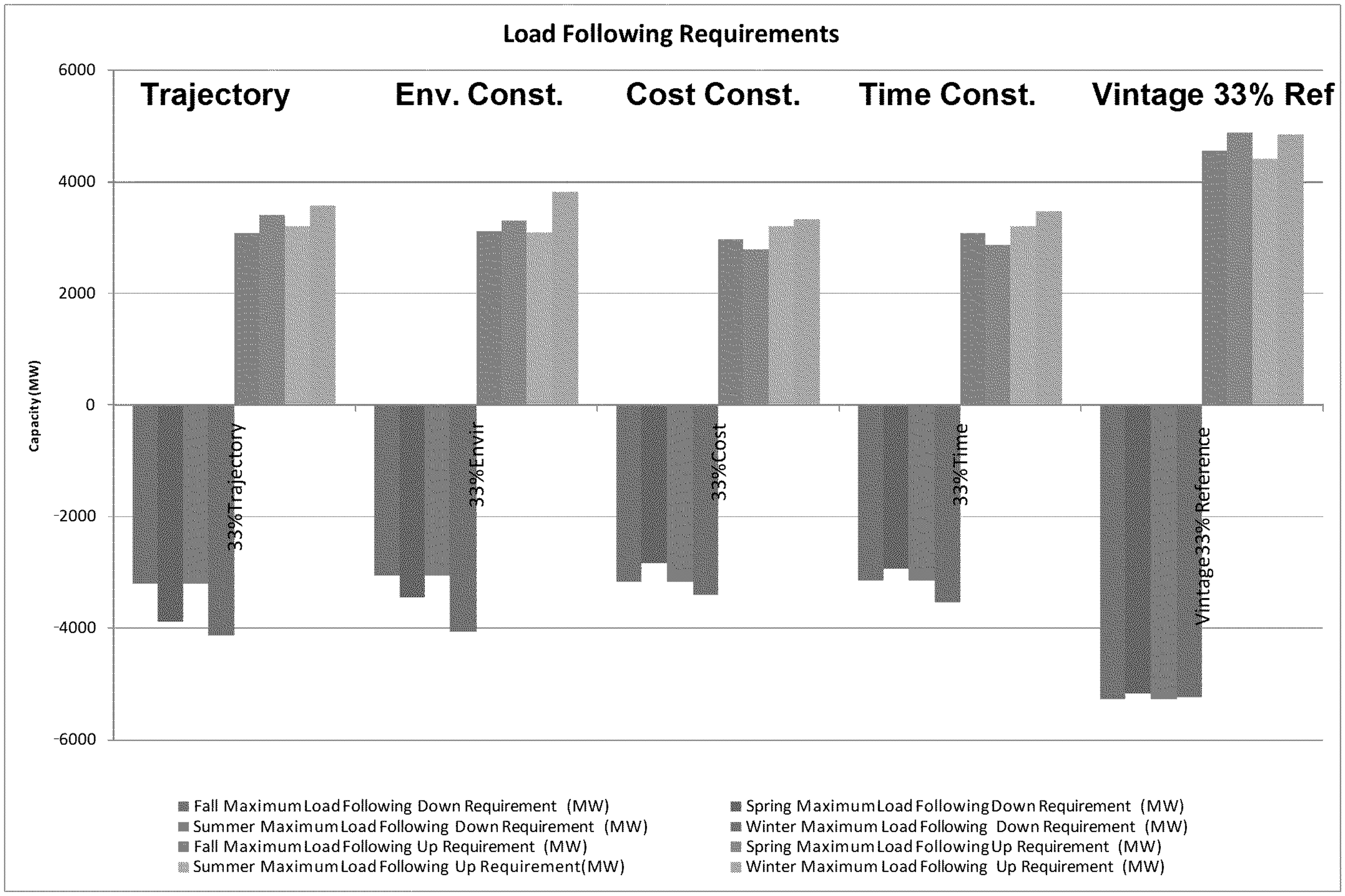
Step 1: Hourly regulation capacity requirements, by scenario



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



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

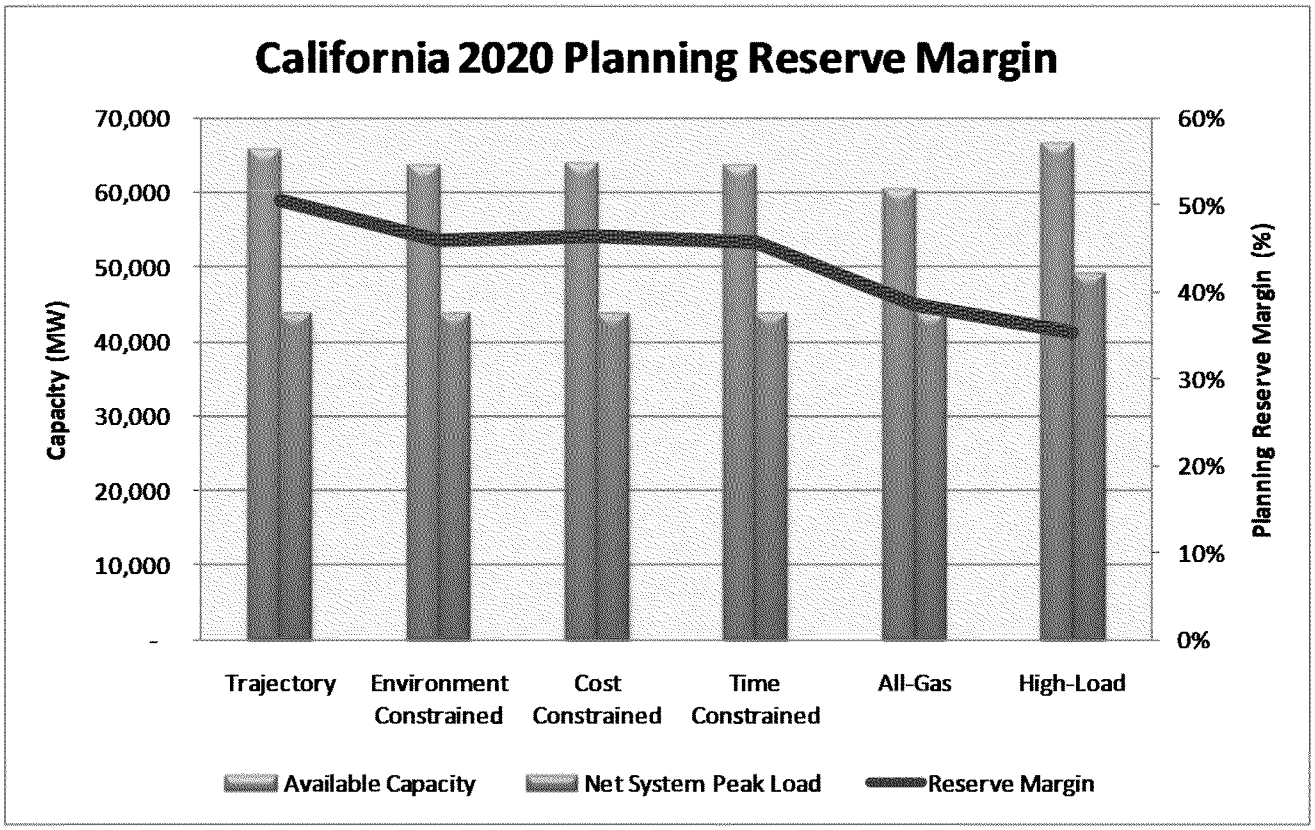
Renewable portfolios for 2020: 2010 LTPP Scenarios

Scenario	Region	Biomass/ biogas	Geothermal	SmallHydro	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**
High Load	CREZ-North CA	3	0	0	900	0	0	1,205	**2,108**
	CREZ-South CA	30	1,591	0	2,502	0	3,069	4,245	**11,437**
	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	1,745	16	4,024	1,052	3,989	9,599	**20,763**

Renewable portfolios for 2020: 2010 LTPP Scenarios

Capacity (MW)	33% Trajectory		33% Env Constrained		33% Cost Constrained		33% Time		33% Trajectroy Low		33% Trajectory High		20% Trajectory		2009 Vintage 33%	
	In-State	Out-of-State	In-State	Out-of-State	In-State	Out-of-State	In-State	Out-of-State	In-State	Out-of-State	In-State	Out-of-State	In-State	Out-of-State	In-State	Out-of-State
Biogas	178	0	178	66	168	73	172	73	178	0	178	0	178	0	1409	
Biomass	126	34	404	156	291	129	212	103	126	34	126	34	126	34		
Geothermal	667	154	240	270	797	202	0	158	617	154	1,591	154	113	154	2598	
Hydro	0	16	0	132	0	14	0	223	0	16	0	16	0	16	680	
Large Scale Solar PV	3,527	340	2,315	340	1,549	340	2,543	340	3,147	340	3,684	340	1,509	340	5432	534
Small Scale Solar PV	1,052	0	9,077	0	1,052	0	2,322	0	1,052	0	1,052	0	1,052	0		
Solar Thermal	3,589	400	1,072	400	1,279	400	1,084	400	1,790	400	3,589	400	1,034	400	6902	
Wind	5,034	4,149	4,426	1,454	5,559	5,639	4,895	7,276	4,006	4,149	5,450	4,149	3,877	1,454	11291	3302
Total	14,173	5,093	17,711	2,818	10,696	6,798	11,228	8,574	10,916	5,093	15,670	5,093	7,889	2,398	28312	

Planning Reserve Margin for 2020 Portfolios: 2010 LTPP Scenarios



Note: Planning reserve margin calculated by E3

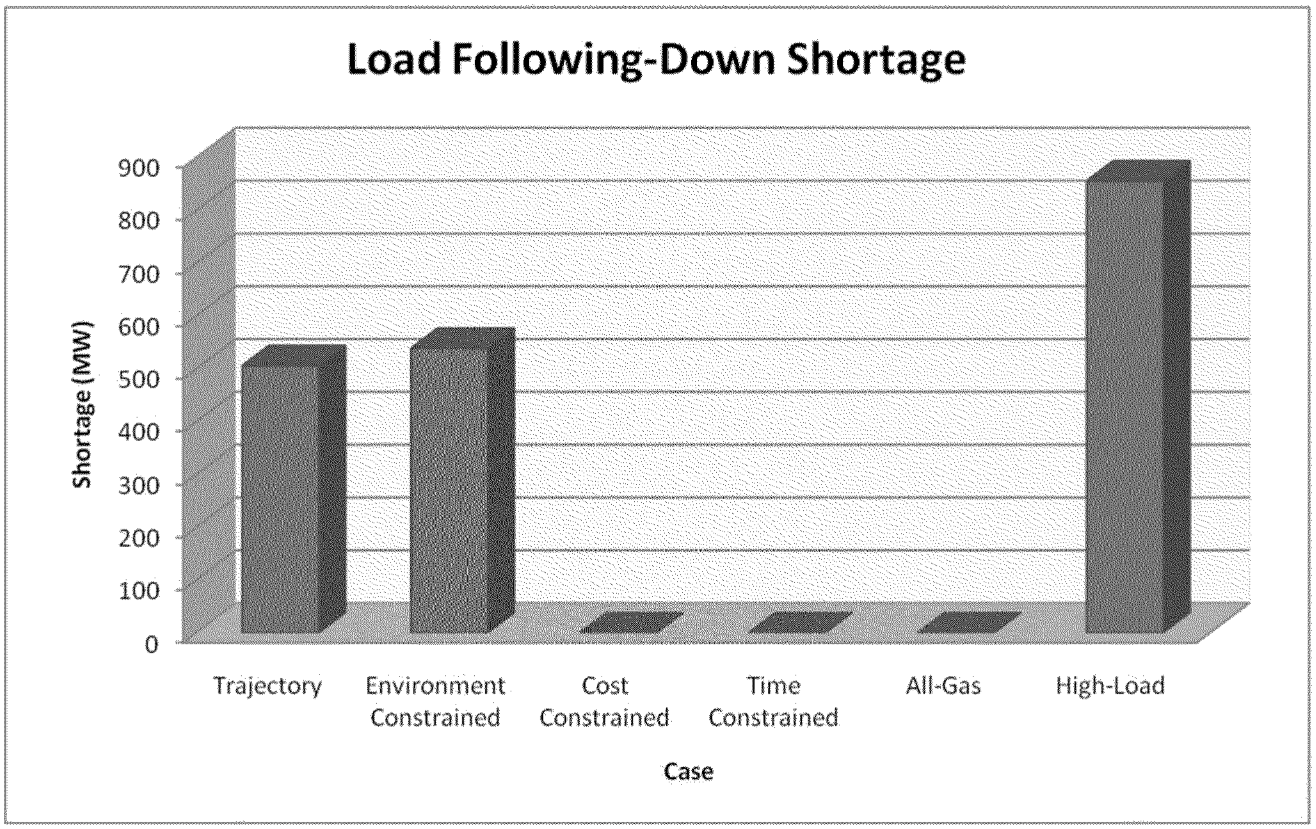
Production simulation results in this section reflect certain assumptions

- 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 an observed operational violations.

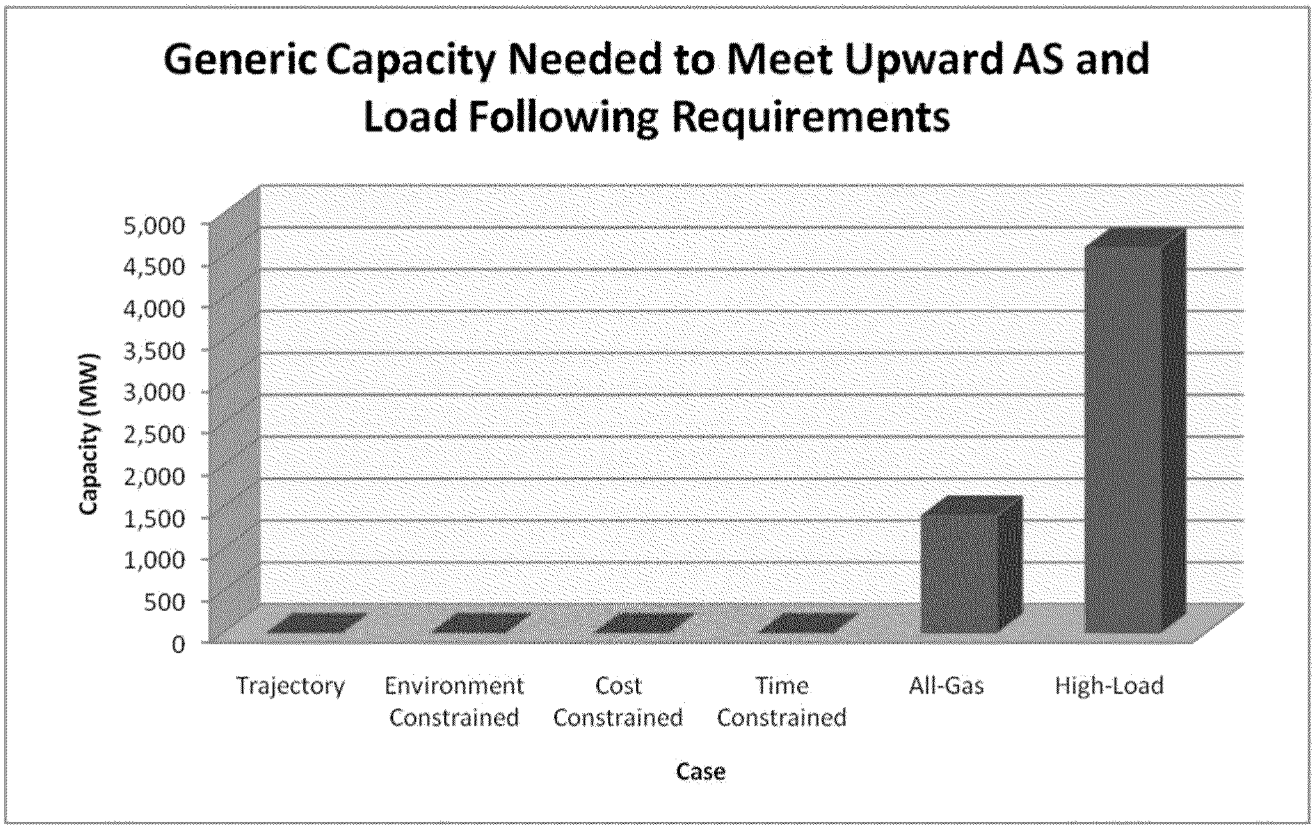
- LTPP analysis did not require adding any generic units to meet PRM because CPUC scoping memo assumptions create a 2020 base dataset that has a significant amount of capacity above PRM
- Next slide shows operational requirement shortages (constraint violations)
- Results for production costs, fuel use and emissions by scenario assume that these resources are added to generation mix

Under CPUC Scoping Memo assumptions, there are some hours with load following down shortages.



Note: No generic capacity is added to meet load following down shortage. Other measures, such as generation curtailment should be able to address this issue

Generic resources are added to meet upward ancillary services and load following requirements in the two additional cases.



Note: There is no upward ancillary service and load following shortage under CPUC Scoping Memo assumptions

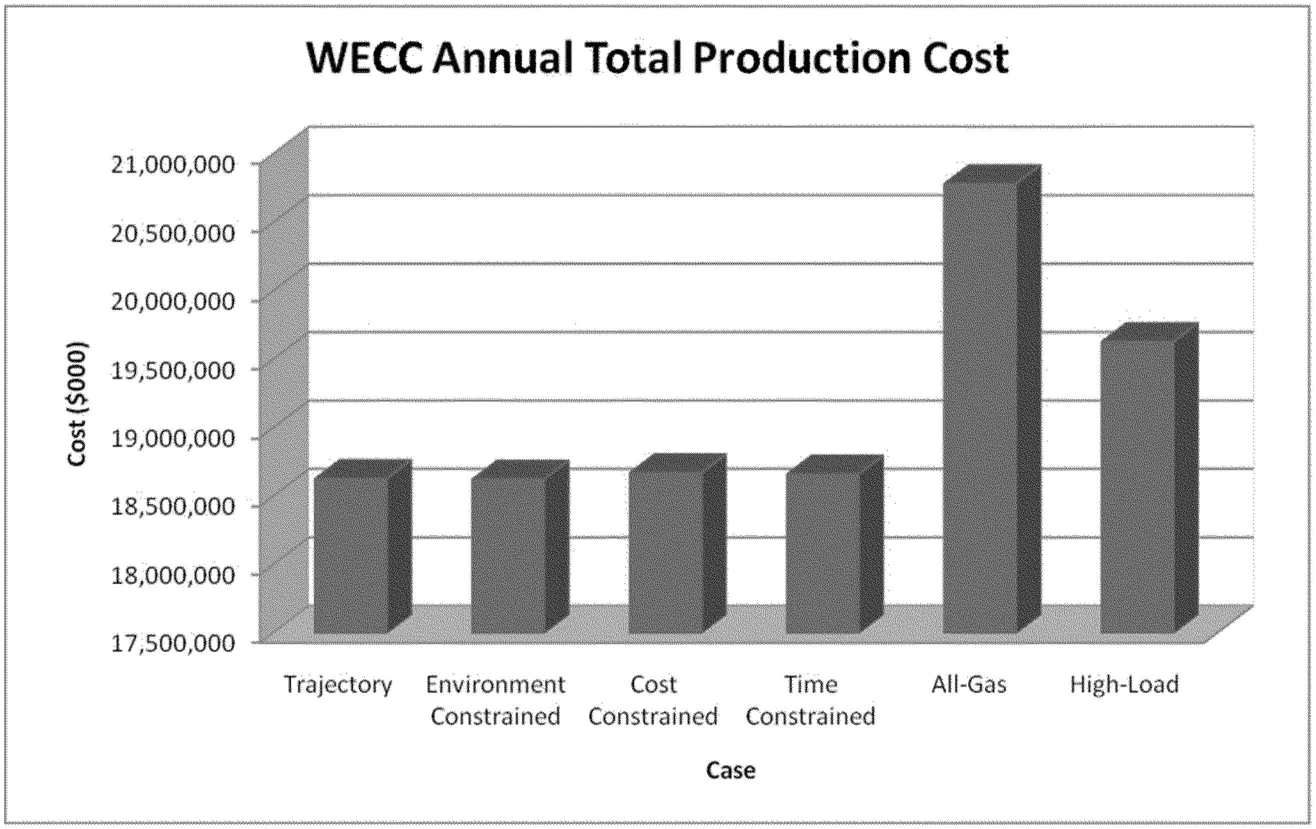
Discussion of results on additional resources

- 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

WECC (including California) annual production costs (in 2020 dollars) by case



Notes: production cost includes generation cost and startup cost

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)

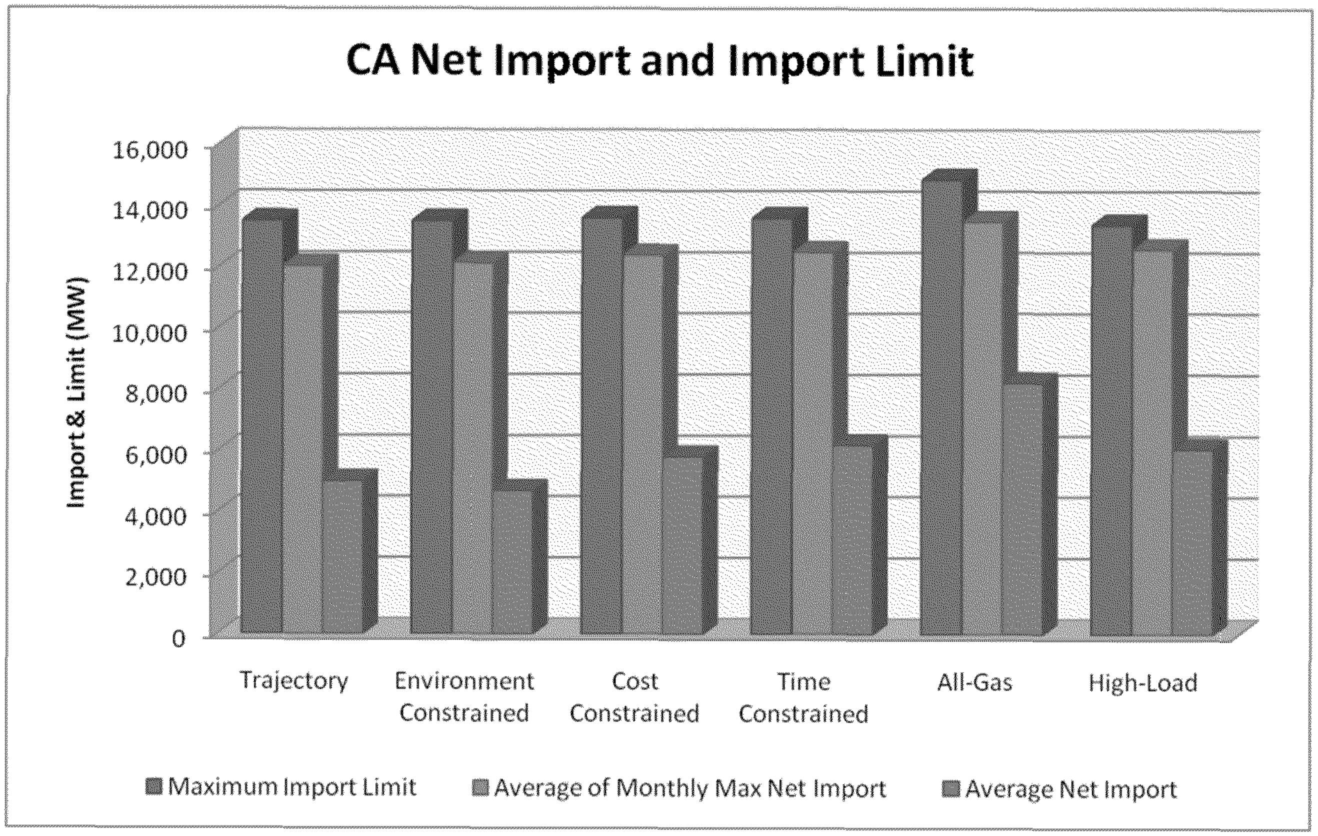
– Cost of Exported Power (out of CA)

- Undesignated (or non-dedicated) Export Costs

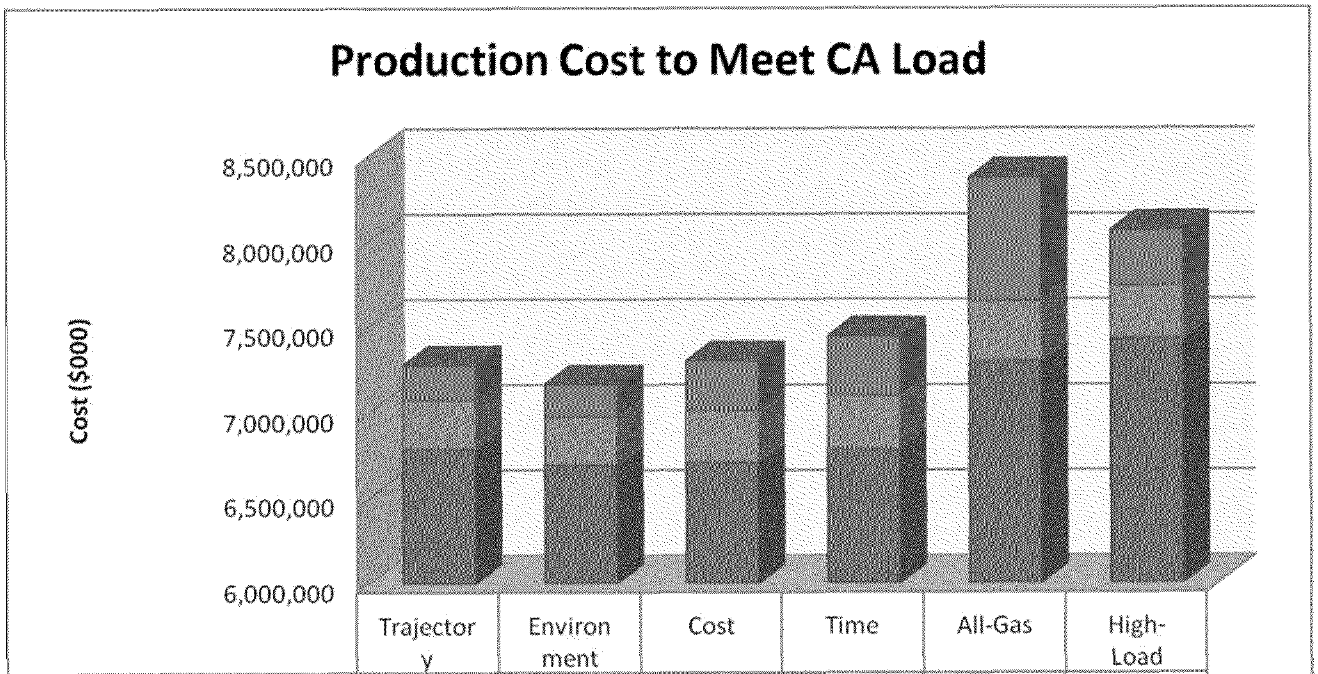
= Total Production Cost of meeting CA load

Note: Dedicated vs. Non-dedicated may also be known as specified or non-specified

California annual net import results by case



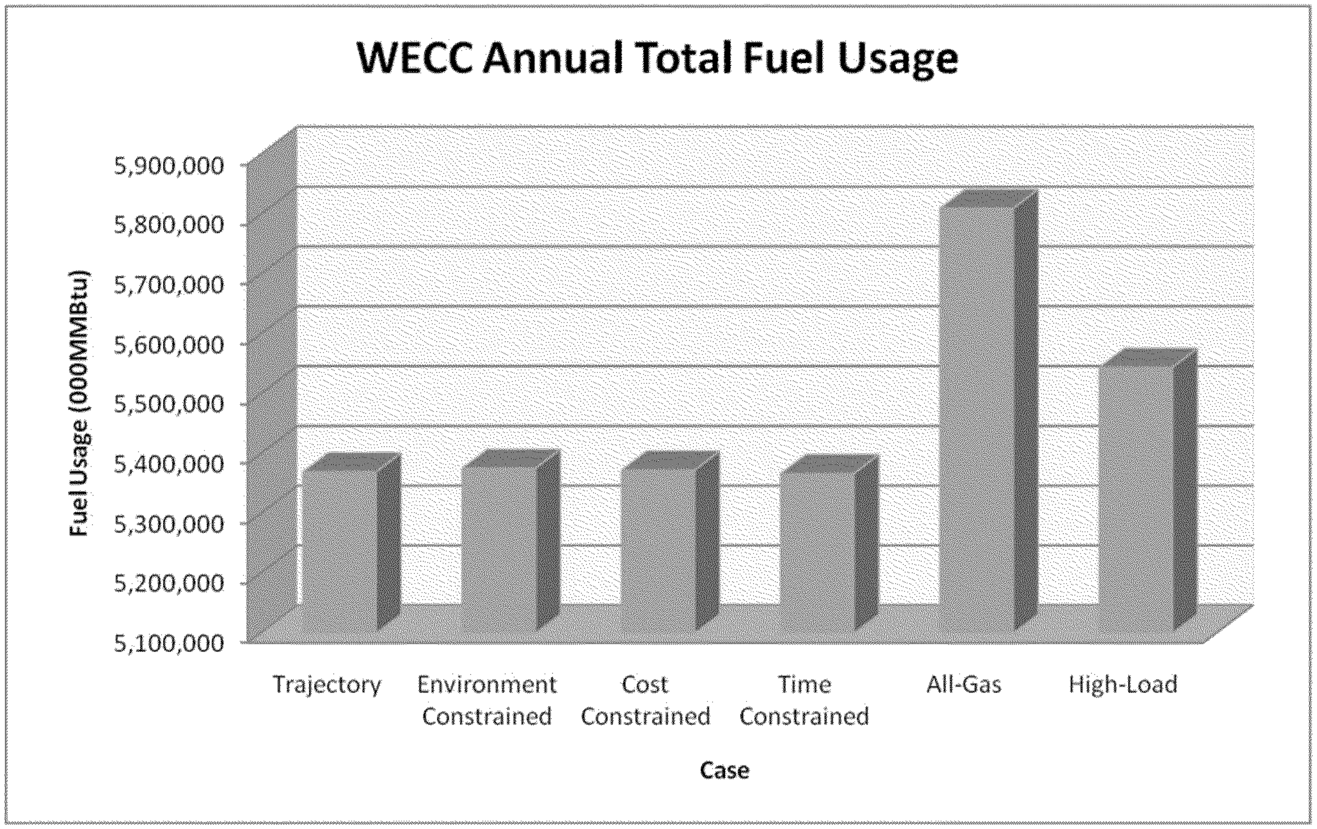
Annual production costs associated with California load (accounting for import/exports), by case



	Trajectory	Environment	Cost	Time	All-Gas	High-Load
Non-Dedicated Import	206,096	190,467	292,175	346,793	722,367	327,348
Dedicated Import	285,028	282,620	305,414	312,970	350,287	306,667
CA Generation	6,787,502	6,691,967	6,705,361	6,785,267	7,300,579	7,432,088

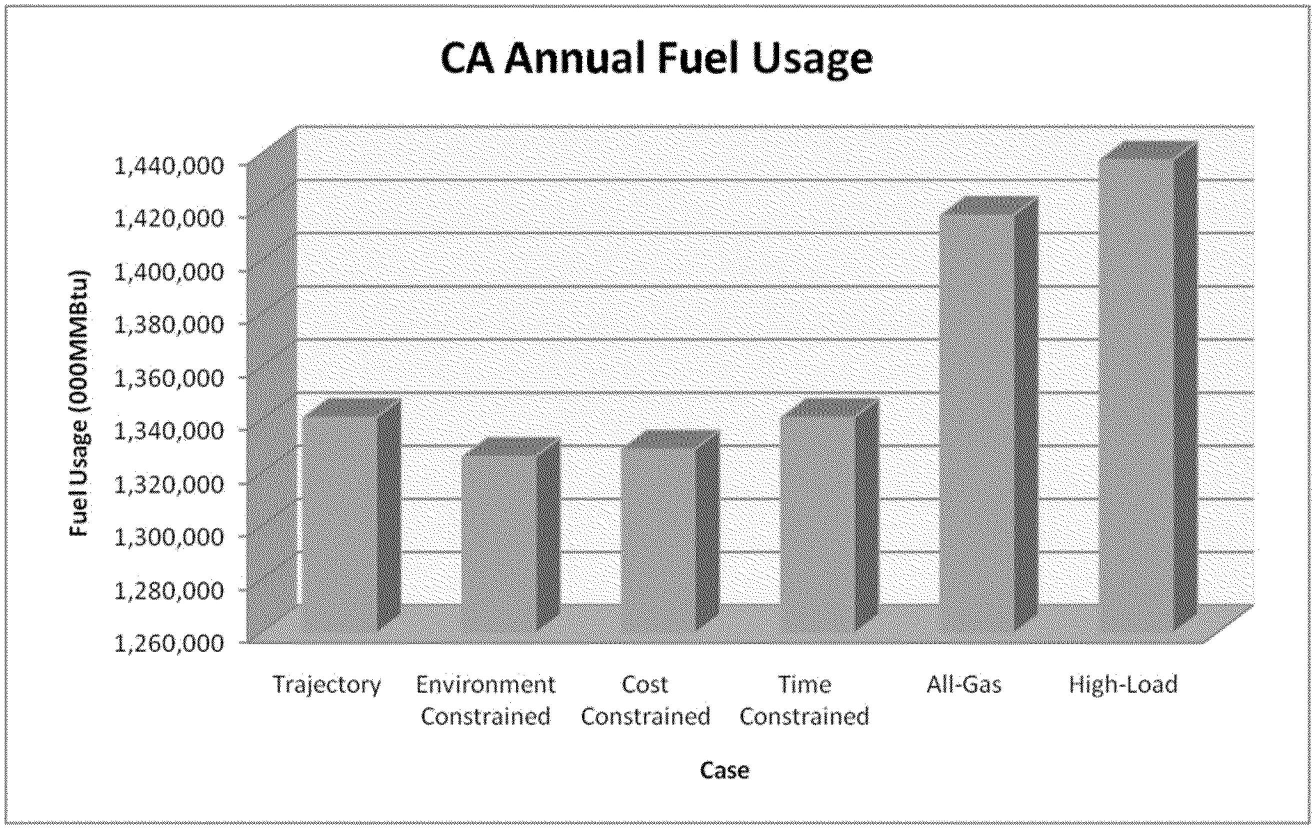
Note: Production cost associated with non-dedicated import is calculated based on the average cost ($/MWh) of each of the regions the energy is imported from; for dedicated import it is based on the actual production cost of each of the dedicated resource and its energy flows into CA

WECC (including California) annual fuel usage (MMBtu), by case



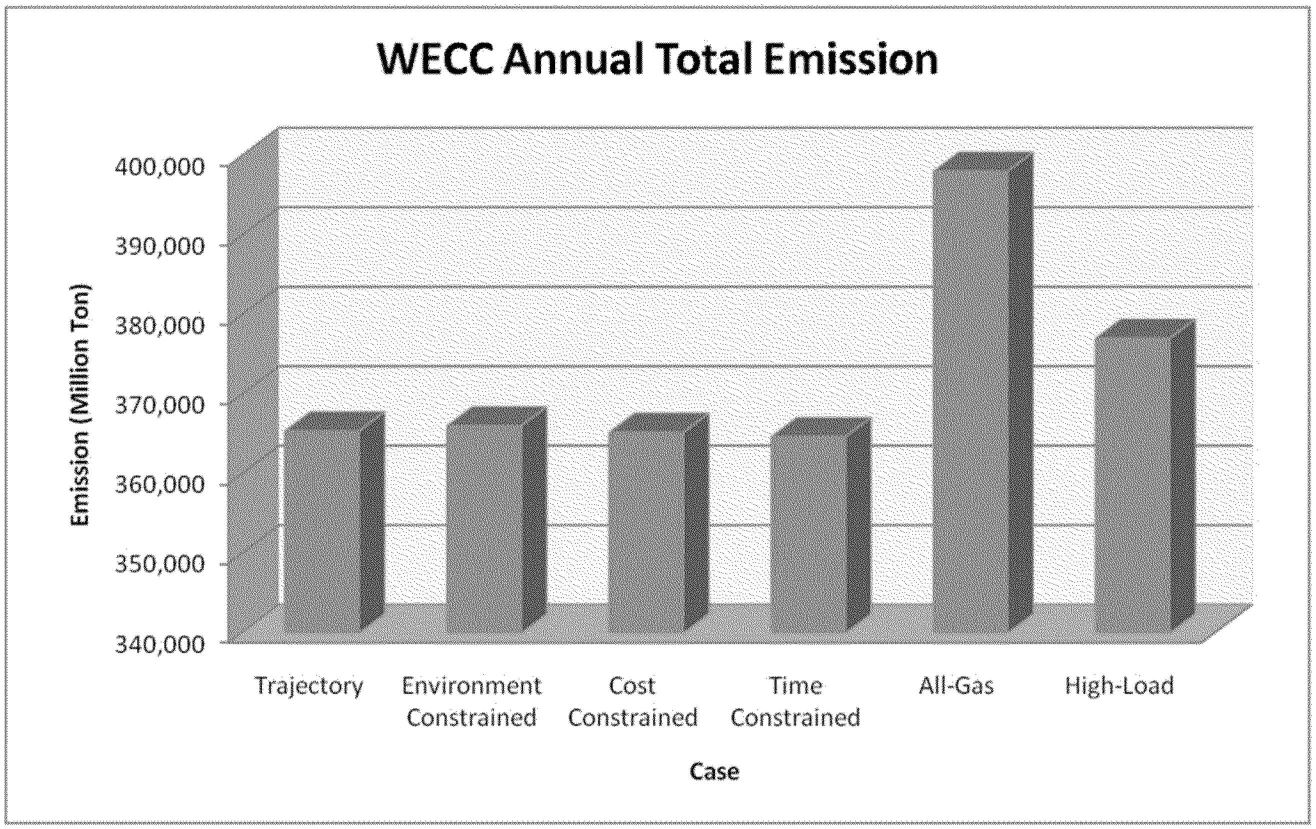
MMBtu = million BTU for conventional/fossil resources

California annual in-state generation fuel usage by case

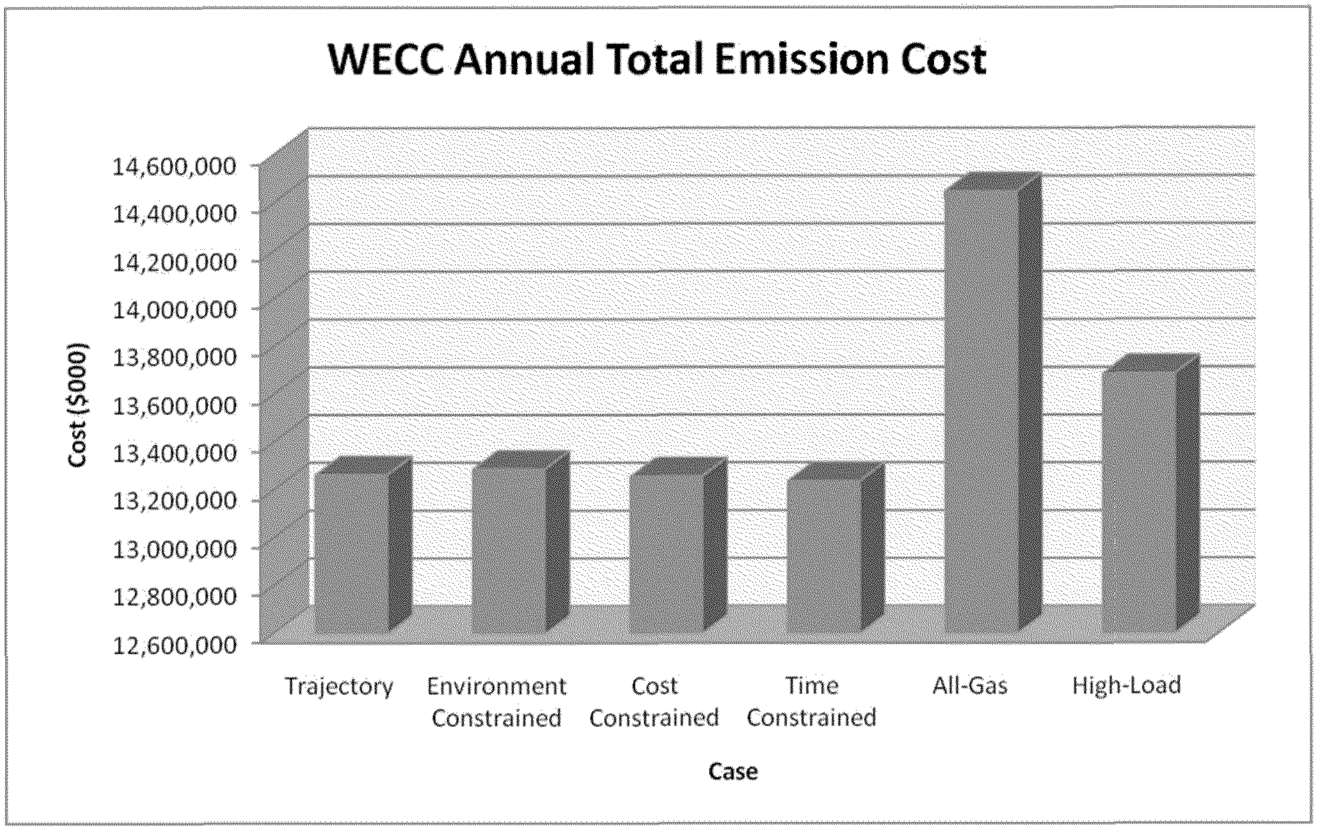


MMBtu = million BTU for conventional/fossil resources

WECC (including California) annual emissions by case



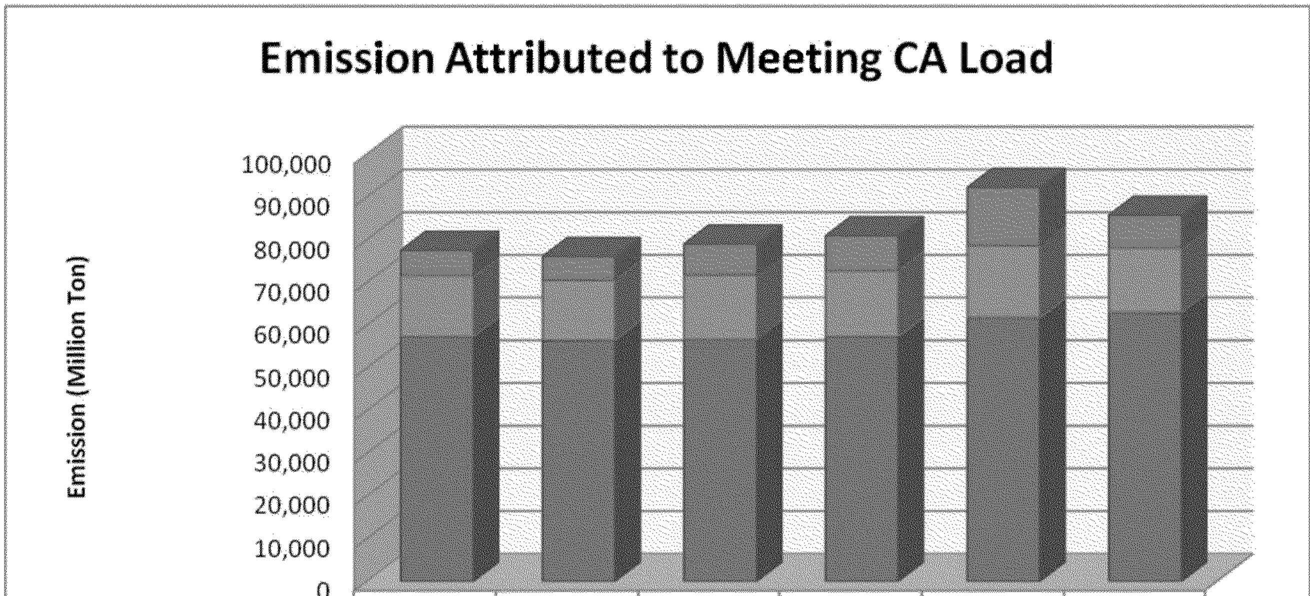
WECC (including California) annual emission costs by case



Calculation of emissions associated with California

- Production simulation modeling output includes GHG emissions (tons) per generator to capture WECC-wide emissions reductions, but:
  - The model solves production simulation for the WECC without considering contractual resources specifically dedicated to meet California load
  - Not all out of state (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)
- 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)

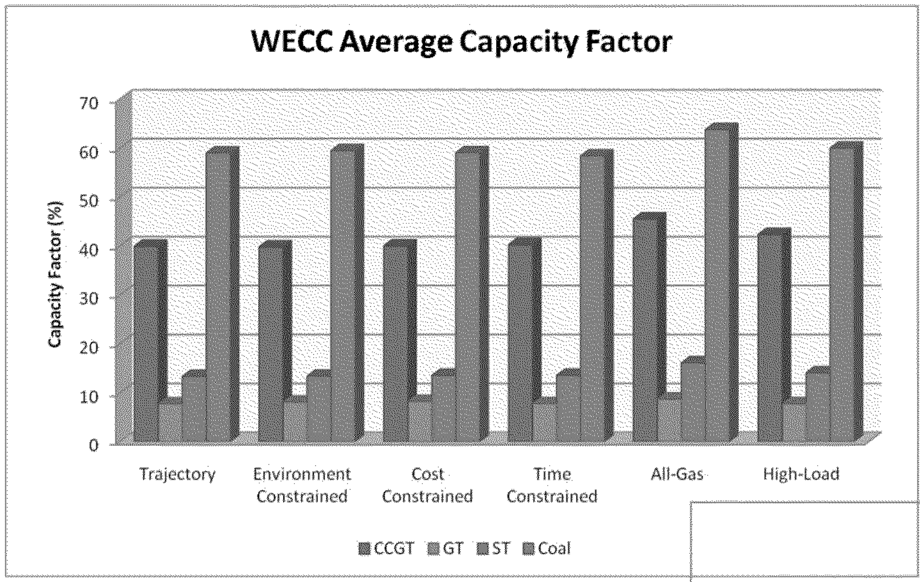
Emissions attributed to meet California load (accounting for Import/Exports), by scenario and emissions source

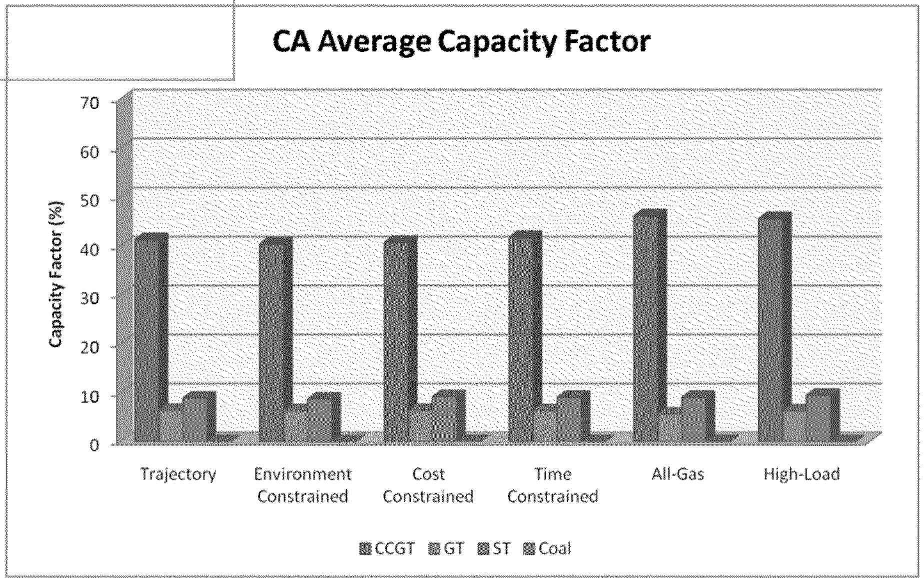


	Trajector y	Environ ment	Cost	Time	All-Gas	High-Load
Non-Dedicated Import	5,959	5,529	7,273	8,218	13,700	7,666
Dedicated Import	14,293	14,095	15,187	15,461	16,889	15,191
CA Generation	57,322	56,478	56,614	57,309	61,710	62,965

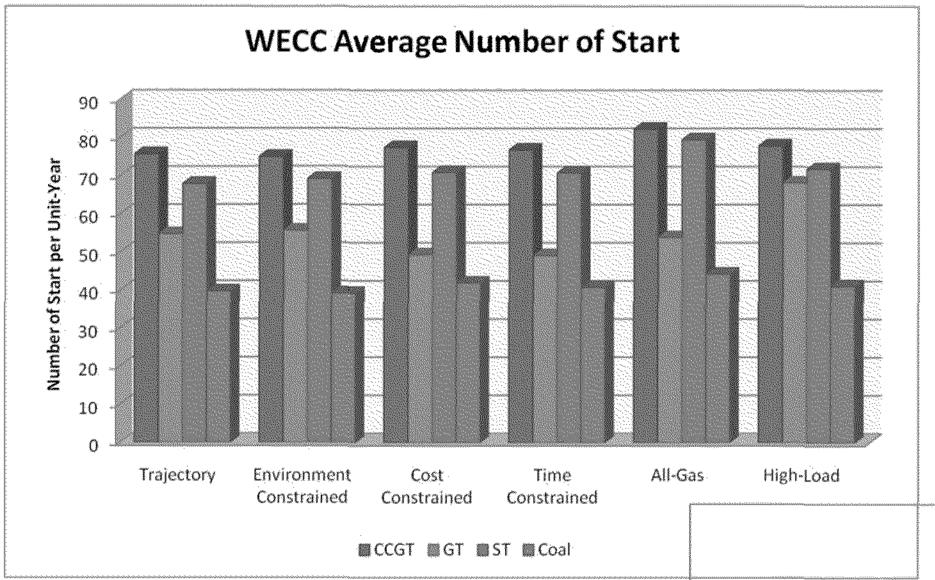
Note: Emissions associated with non-dedicated import is calculated based on the average emission rate (ton/GWh) of each of the regions the energy is imported from; for dedicated import it is based on the actual emission of each of the dedicated resource and its energy flows into CA

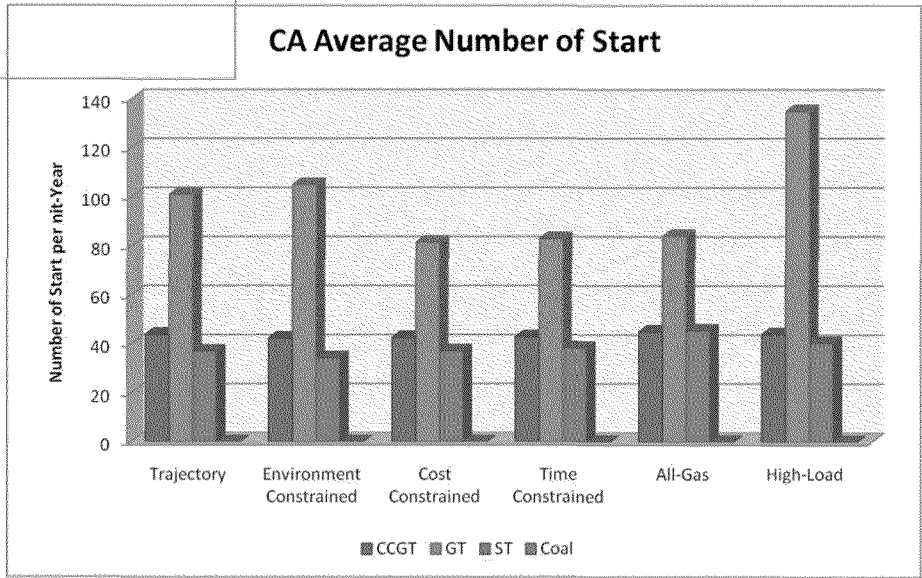
WECC and California annual average capacity factors by case





WECC and California annual average number of startup by case





Comparison of WECC (including CA) and CA results

Case	Trajectory	Environment	Cost	Time	All-Gas	High-Load
Annual Average Capacity Factor (%)						
WECC						
CCGT	39.9	39.8	40.0	40.3	45.5	42.3
GT	7.7	8.1	8.2	7.8	8.7	7.7
ST	13.3	13.4	13.5	13.5	16.1	14.1
Coal	59.0	59.5	59.0	58.4	63.7	60.0
CA						
CCGT	41.3	40.4	40.7	41.7	46.1	45.5
GT	6.4	6.3	6.4	6.3	5.6	6.3
ST	8.9	8.7	9.2	9.1	9.1	9.5
Coal	N/A	N/A	N/A	N/A	N/A	N/A

Number of Start per Unit per Year						
WECC						
CCGT	75.7	74.9	77.4	76.8	82.2	77.9
GT	54.7	55.6	49.3	49.0	53.8	68.1
ST	67.9	69.1	70.9	70.7	79.4	71.8
Coal	39.7	39.2	41.9	40.7	44.2	41.1
CA						
CCGT	43.9	42.3	42.6	42.8	44.9	44.0
GT	100.9	104.9	81.4	82.9	84.0	134.8
ST	37.0	34.2	37.1	38.4	45.5	40.4
Coal	N/A	N/A	N/A	N/A	N/A	N/A

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 demand response

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 Net Qualifying Capacity (NQC) as of August 2nd, 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
  - Combined cycle resources 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 Planning Reserve Margin 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 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
- Modeled Coolwater 3 and 4 instead of assumed retired.

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 4 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	12,726	10,290	11,331	8,405
Total California Import Limit	13,526	11,090	12,131	9,205
Environmental Case				
S. Cal Import Limit to be used for study	12,724	10,224	11,349	8,340
Total California Import Limit	13,524	11,024	12,149	9,140
Cost Case				
S. Cal Import Limit to be used for study	12,833	10,186	11,457	8,302
Total California Import Limit	13,633	10,986	12,257	9,102
Time Case				
S. Cal Import Limit to be used for study	12,819	10,224	11,427	8,340
Total California Import Limit	13,619	11,024	12,227	9,140
All-Gas				
S. Cal Import Limit to be used for study	14,086	10,735	12,110	8,851
Total California Import Limit	14,886	11,535	12,910	9,651
High-Load				
S. Cal Import Limit to be used for study	12,610	10,237	11,270	8,352
Total California Import Limit	13,410	11,037	12,070	9,152

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

California ISO
Shaping a Renewed Future

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	SmallHydro	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

California ISO
Shaping a Renewed Future

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 (Std Dev)

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

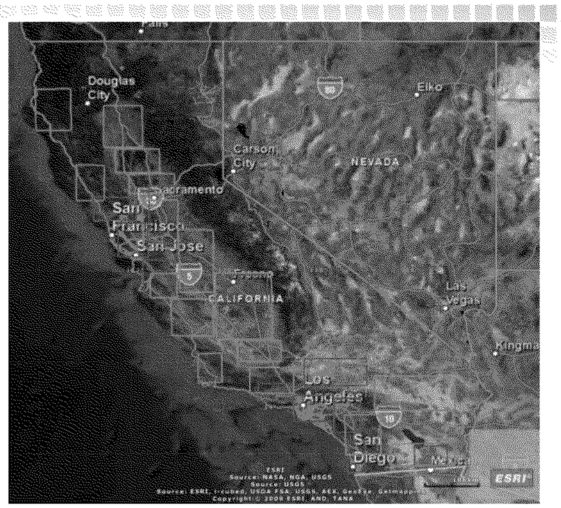
PIRP Forecast Error								
Region	Tech	MW	Persistent	Hour	Spring	Summer	Fall	Winter
CA	Wind	1005	T-2	All	11.1%	10.8%	8.1%	6.0%
CA	Wind	1005	T-1	All	8.4%	7.1%	5.3%	3.9%
CA	Wind	1005	PIRP	All	10.5%	8.9%	8.4%	6.7%

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-1 hr* persistence
- To address issues that arise using the *T-1 hr* 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

California ISO
Shaping a Renewed Future

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-minute upward ramp capability
  - Regulation-down provision is less than or equal to 10-minute downward ramp capability
- 20-minute constraint
  - The sum of upward AS and load following up provisions is less than or equal to 10-minute upward ramp capability
  - The sum of regulation-down and load following down provisions is less than or equal to 10-minute 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 tiered 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

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

ADDITIONAL CHANGES TO MODEL ASSUMPTIONS

California ISO
Shaping a Renewed Future

Additional changes were implemented based on May 31, 2011 ALJ ruling

- Corrected the calendar year for load profile, renewable profiles, and Step 1 requirements
- Reset heat rate of El Segundo plant and the minimum capacity of the LMS100 and LM6000 units based on public available information
- Added CoolwtrS3 and CoolwtrS4 units according to ISO transmission planning assumptions
- Disallowed existing GT to provide off-line non-spinning, new GT is allowed
- Created a generic unit reflective of storage or curtailment to absorb load following down shortage

Additional changes were implemented based on May 31, 2011 ALJ ruling (cont.)

- Updated transmission wheeling rates as follows:
  - Using TEPPC PC0 Case non-zero rate for paths outside CA
  - Using vintage rates for paths in CA and for paths outside CA where PC0 Case has zero rates
- Separated BC and AESO and applied a $48/MW wheeling rate (based on PC0 Case) to prevent large quantity of energy from flowing into AESO
- Switched the following dynamic resources to providing load following and ancillary services to meet the ISO requirements
  - APEX_2_MIRDYN (505 MW)
  - MRCHNT_2_MELDYN (439 MW)
  - MSQUIT_5_SERDYN (1,182 MW)
  - SUTTER_2_PL1X3 (500 MW)

Additional changes were implemented based on May 31, 2011 ALJ ruling (cont.)

- Changed modeling of coal units with capacity greater than 300 MW to subject to commitment decision (integer variable)
- Updated SCIT and CA import limits based the revised SCIT model
- Revised generator outage rates to match monthly average outage (MW) with the ISO 2010 monthly minimum outage , no maintenance from Nov to Feb in Humboldt area

Outage profile used compared with actual outage profile

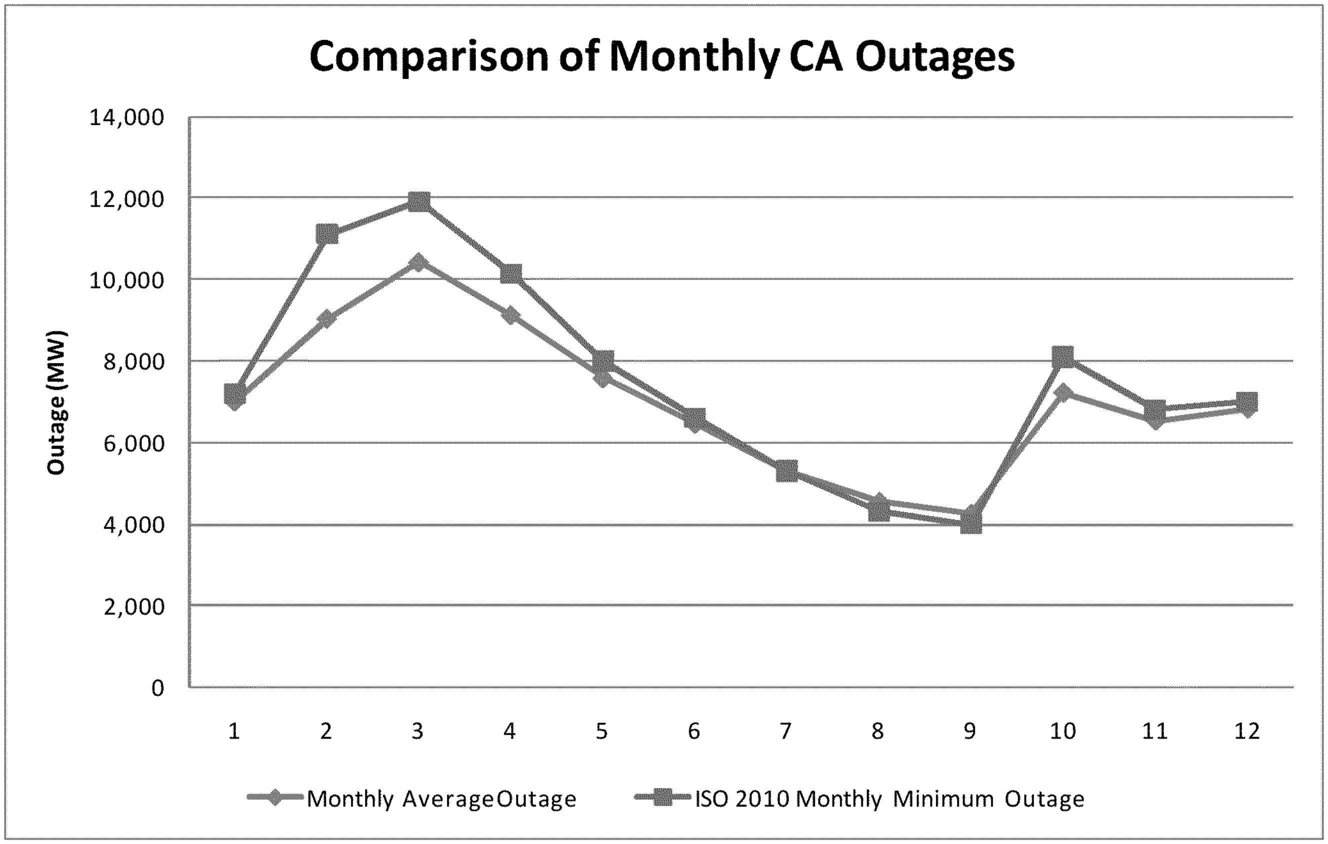


Exhibit 2

Large Solar Profiles (Spreadsheet 1)
Small Solar Profiles (Spreadsheet 2)
Projects All Cases – Final (Spreadsheet 3)

SOLAR - LARGE SCALE PV

CREZ Number	Location	Profile Name	Plant	Size MW	Type	E3 Cap. Factor	20%	33% Base	33% Enviro n.	33% High	33% Cost	33% Time	Geographical Location Latitude	Longitude
1	Alberta													
2	Arizona	Arizona_PV_1	2_PV_1	290	Crystalline Tracking	29.00%	x	x	x	x	x	x	32.886545	-114.90047
		Arizona_PV_2	2_PV_2	50	Crystalline Tracking	29.00%	x	x	x	x	x	x	33.663188	-114.72181
3	Carrizo South	Carrizo South_PV_1	3_PV_1	150	Thin-Film	23.50%	x	x	x	x	x	x	35.430045	-120.10157
		Carrizo South_PV_2	3_PV_2	400	Thin-Film	23.50%		x	x	x	x	x	35.392808	-120.06802
		Carrizo South_PV_3	3_PV_3	350	Crystalline Tracking	26.65%		x	x	x	x	x	35.337966	-120.00224
		Carrizo South_PV_4	3_PV_4	87.9	Crystalline Tracking	26.65%	x						same as PV_3	
		Carrizo South_PV_5	3_PV_5	238	Thin-Film	23.50%	x						same as PV_2	
4	Colorado													
5	Fairmont	Fairmont_PV_1	5_PV_1	38.8	Crystalline Tracking	29.00%				x			34.668333	-118.31013
6	Imperial	Imperial_PV_1	6_PV_1	174.4	Crystalline Tracking	29.00%				x			33.072536	-115.79915
		Imperial_PV_2	6_PV_2	55.8	Crystalline Tracking	29.00%		x					32.785496	-115.82318
		Imperial_PV_3	6_PV_3	49.4	Crystalline Tracking	29.00%					x		same as PV_2	
		Imperial_PV_4	6_PV_4	15.3	Crystalline Tracking	29.00%			x				same as PV_2	
7	Kramer													
8	Montana													
9	Mountain Pass	Mountain Pass_PV_1	9_PV_1	300	Crystalline Tracking	29.00%		x		x			35.465079	-115.53964
10	New Mexico													
11	Non CREZ*	Non CREZ_PV_1	11_PV_1	50	Crystalline Tracking	26.65%	x	x	x	x	x	x	35.803622	-120.06311
		Non CREZ_PV_2	11_PV_2	232	Crystalline Tracking	26.65%		x		x			35.649326	-119.81615
12	Northwest													
13	Palm Springs													
14	Pisgah	Pisgah_PV_1	14_PV_1	75	Crystalline Tracking	29.75%		x		x			34.857423	-116.86747
15	Riverside East	Riverside East_PV_1	15_PV_1	300	Thin-Film	26.63%	x	x	x	x	x	x	33.814102	-115.40466
		Riverside East_PV_2	15_PV_2	250	Thin-Film	26.63%	x	x	x	x	x	x	33.867651	-115.20561
		Riverside East_PV_3	15_PV_3	83	Crystalline Tracking	28.73%						x	33.770942	-115.25427
		Riverside East_PV_4	15_PV_4	375	Crystalline Tracking	27.42%						x	33.571726	-114.83828
16	Round Mountain													
17	San Bernardino-Lucern	San Bernardino-Lucerne_PV_1	17_PV_1	30	Crystalline Tracking	29.35%						x	34.396817	-116.8591
18	San Diego South													
19	Solano													
20	Tehachapi	Tehachapi_PV_1	20_PV_1	341	Thin-Film	23.50%		x		x			34.966646	-118.24769
		Tehachapi_PV_2	20_PV_2	341	Thin-Film	23.50%		x		x			35.063749	-118.22219
		Tehachapi_PV_3	20_PV_3	341	Thin-Film	23.50%		x		x			35.018323	-118.28698
		Tehachapi_PV_4	20_PV_4	341	Thin-Film	23.50%		x		x			35.215425	-118.02372
		Tehachapi_PV_5	20_PV_5	66	Crystalline Tracking	29.00%						x	34.881536	-118.39869
		Tehachapi_PV_6	20_PV_6	244.2	Thin-Film	23.50%						x	same as PV_1	
		Tehachapi_PV_7	20_PV_7	244.2	Thin-Film	23.50%						x	same as PV_2	
21	Utah-Southern Idaho													
22	Westlands	Westlands_PV_1	22_PV_1	400	Crystalline Tracking	25.42%			x				36.195572	-119.96354
		Westlands_PV_2	22_PV_2	400	Crystalline Tracking	25.42%			x				36.142356	-119.92725
23	Wyoming													
					Total PV		1416	3867	2655	4024	1889	2882		
					Total ST		1379	3989	1472	3989	1679	1484		
					Total Large		2795	7856	4127	8013	3568	4366		

SOLAR THERMAL

CREZ Number	Location	Profile Name	Plant	Size MW	Type	E3 Cap. Factor	20%	33% Base	33% Enviro n.	33% High	33% Cost	33% Time	Geographical Location Latitude	Longitude	
2	Arizona	Arizona_ST_1	2_ST_1	200	Solar Thermal	26.68%	x	x	x	x	x	x	32.9322548	-114.9322913	Used Imperial East CREZ
		Arizona_ST_2	2_ST_2	200	Solar Thermal	26.68%	x	x	x	x	x	x	33.7537524	-114.7514557	Used Riverside East CREZ
6	Imperial	Imperial_ST_1	6_ST_1	300	Solar Thermal	26.68%		x		x	x		33.2206533	-116.0048792	
		Imperial_ST_2	6_ST_2	92.7	Solar Thermal	26.68%			x				same as ST_1		
7	Kramer	Kramer_ST_1	7_ST_1	62	Solar Thermal	26.68%	x	x	x	x	x	x	35.1084332	-117.7163435	
9	Mountain Pass	Mountain Pass_ST_1	9_ST_1	110	Solar Thermal	26.68%		x		x			35.5866729	-115.446041	
		Mountain Pass_ST_2	9_ST_2	300	Solar Thermal	26.68%		x		x			35.4923461	-115.3113427	
11	Non CREZ*	Non CREZ_ST_1	11_ST_1	150	Solar Thermal with storage	36.00%	x	x	x	x	x	x	34.0444487	-114.81998	Rice Solar Energy Project (Central Receiver)
		Non CREZ_ST_2	11_ST_2	370	Solar Thermal	26.68%		x		x			35.0333172	-117.2707933	
14	Pisgah	Pisgah_ST_1	14_ST_1	250	Solar Thermal	26.68%		x		x			34.8126127	-116.4471117	
		Pisgah_ST_2	14_ST_2	250	Solar Thermal	26.68%		x		x			34.8416388	-116.552886	
		Pisgah_ST_3	14_ST_3	275	Solar Thermal	26.68%	x		x		x	x	same as 1		
		Pisgah_ST_4	14_ST_4	400	Solar Thermal	26.68%		x		x			34.8248006	-116.5620832	
		Pisgah_ST_5	14_ST_5	400	Solar Thermal	26.68%		x		x			34.7943576	-116.3915522	
		Pisgah_ST_6	14_ST_6	400	Solar Thermal	26.68%		x		x			34.7681692	-116.4275202	
15	Riverside East	Riverside East_ST_1	15_ST_1	250	Solar Thermal	26.68%	x	x	x	x	x	x	33.7016856	-115.2151098	
		Riverside East_ST_2	15_ST_2	242	Solar Thermal	26.68%	x	x	x	x	x	x	33.626464	-114.977981	
20	Tehachapi	Tehachapi_ST_1	20_ST_1	105	Solar Thermal	26.68%		x		x		x	35.0600689	-117.9914446	
							1379	3989	1472	3989	1679	1484			

Exhibit 2
Projects

Technology:	Large Ground	fixed tilt - 25 degrees cadmium telluride
	Large Roof	fixed tilt - 15 degrees polycrystalline

SMALL SOLAR

Area Number	Location	Profile Name	Plant	Size MW	Type	Number of Sites	E3 Cap. Factor	20%	33% Base	33% Envir	33% High	33% Cost	33% Time	Geographical Location Latitude X1	Latitude X2	Longitude Y1	Longitude Y2	Notes
1	Central Valley	Large_Ground_1	1_LG_1	406.5	fixed tilt - 25 degre	13	23.56%	x	x	x	x	x	x	35.486	36.921	-120.133	-118.954	
		Large_Ground_2	1_LG_2	461.9	fixed tilt - 25 degre	15	23.63%			x				36.516	37.86	-120.928	-120.215	(302.9+132.9+26.1)
		Large_Ground_3	1_LG_3	418.9	fixed tilt - 25 degre	5	23.56%			x				37.484	38.518	-121.732	-120.991	
		Large_Ground_4	1_LG_4	530.1	fixed tilt - 25 degre	1	23.56%			x				38.671	39.096	-122.031	-121.065	
		Large_Ground_5	1_LG_5	387.9	fixed tilt - 25 degre	2	23.56%			x				39.119	39.624	-122.332	-121.396	
		Large_Ground_6	1_LG_6	174.1	fixed tilt - 25 degre	9	23.56%			x			x	35.011	35.452	-119.676	-118.744	
		Large_Ground_7	1_LG_7	457.4	fixed tilt - 25 degre	6	23.56%			x				39.68	40.572	-122.591	-121.769	
		Mid_Ground		132.9		22	23.56%							merged with Large_Ground_2				
		Small_Ground		26.1		21	25.57%							merged with Large_Ground_2				
		Large_Roof_1	1_LR_1	165.2	fixed tilt - 15 degre	2	20.37%			x			x	36.237	36.888	-119.919	-119.047	
		Large_Roof_2	1_LR_2	544.8	fixed tilt - 15 degre	5	20.37%			x				37.584	38.838	-121.586	-120.92	
	Mojave	Large_Ground_8	2_LG_1	120	fixed tilt - 25 degre	7	26.68%	x	x		x	x	x	34.939	35.215	-117.999	-117.405	
		Large_Ground_9	2_LG_2	48.1	fixed tilt - 25 degre	9	26.68%			x			x	34.939	35.135	-117.035	-116.716	
		Large_Ground_10	2_LG_3	367.6	fixed tilt - 25 degre	14	26.68%			x				33.941	34.687	-116.682	-114.951	355.1+12.5
		Large_Ground_11	2_LG_4	433	fixed tilt - 25 degre	14	26.68%			x				32.71	33.227	-116.332	-114.944	
		Mid_Ground		12.5		21	26.68%			1				merged with Large_Ground_10				
		Small_Ground		3						1				not included				
		Large Roof		17.8	fixed tilt - 15 degre	5	22.80%	1	1	1	1	1	1	merged with Large_Roof_8				
		Large_Roof_3	2_LR_1	115.4	fixed tilt - 15 degre	4	22.80%			x			x	32.683	33.162	-115.803	-115.105	
		Large_Roof_4	2_LR_2	380	fixed tilt - 15 degre	10	22.80%			x				34.455	35.069	-118.216	-116.871	
	North Coast	Large_Ground_12	3_LG_1	88.5	fixed tilt - 25 degre	5	21.87%	x	x	x	x	x	x	36.395	36.908	-121.578	-120.999	
		Large_Ground_13	3_LG_2	59.6	fixed tilt - 25 degre	6	21.87%			x			x	38.518	39.272	-123.97	-122.603	
		Large_Ground_14	3_LG_3	356.6	fixed tilt - 25 degre	16	21.87%			x				35.563	36.349	-121.106	-120.228	
		Large_Ground_15	3_LG_4	302	fixed tilt - 25 degre	4	21.87%			x				40.056	40.951	-124.067	-123.326	240.5+48.4+13.1
		Mid_Ground		48.4		15	21.87%			1				merged with Large_Ground_15				
		Small_Ground		13.1		14	23.71%			1				merged with Large_Ground_15				
		Large Roof		18	fixed tilt - 15 degre	5	19.56%	1	1	1	1	1	1	merged with Large_Roof_8				
		Large_Roof_5	3_LR_1	212.2	fixed tilt - 15 degre	4	19.56%			x			x	38.092	38.582	-122.819	-121.893	
		Large_Roof_6	3_LR_2	341.2	fixed tilt - 15 degre	7	19.56%			x				37.291	38.001	-122.274	-121.643	
		Large_Roof_7	3_LR_3	358.6	fixed tilt - 15 degre	3	19.56%			x				36.416	37.2	-121.718	-121.071	
	South Coast	Large Ground		20		1	24.34%	1	1	1	1	1	1	merged with Large_Ground_12				
		Large_Ground_16	4_LG_1	151.2	fixed tilt - 25 degre	6	24.34%			x			x	34.543	35.18	-120.534	-120.031	
		Large_Ground_17	4_LG_2	424.7	fixed tilt - 25 degre	17	24.34%			x				34.309	34.85	-119.418	-118.454	
		Large_Ground_18	4_LG_3	335	fixed tilt - 25 degre	3	24.34%			x				32.977	33.837	-117.314	-116.581	
		Mid & Small Ground		7.8		28	24.34% and 26.1%			1				merged with Large_Ground_18				
		Large_Roof_8	4_LR_1	430	fixed tilt - 15 degre	15	21.17%	x	x	x	x	x	x	33.692	34.261	-118.449	-117.58	
		Large_Roof_9	4_LR_2	261.4	fixed tilt - 15 degre	4	21.17%			x			x	34.141	34.523	-119.226	-118.466	
		Large_Roof_10	4_LR_3	453.9	fixed tilt - 15 degre	4	21.17%			x				33.456	34.196	-117.559	-117.002	
		Large_Roof_11	4_LR_4	408.2	fixed tilt - 15 degre	7	21.17%			x				32.588	33.24	-117.261	-116.909	
					Total Small PV			1,045	1,045	9,074	1,045	1,045	2,232					

Exhibit 2
Projects - Final

	MW	Energy
Total DG	1749.28	3218
	Nameplate at CF=21.0%	

DISTRIBUTED SOLAR

Area Number	Location	Profile Name	Plant	Size MW	Type	Number of Sites	E3 Cap. Factor	20%	33% Base	33% Enviro	33% High	33% Cost	33% Time	Geographical Location Latitude X1	Latitude X2	Longitude Y1	Longitude Y2
	Central Valley	Distributed_Solar_1	1_DS_1	349.9	fixed tilt		21.00%	x	x	x	x	x	x	37.765	38.824	-121.638	-121.065
	Central Valley	Distributed_Solar_2	1_DS_2	349.9	fixed tilt		21.00%	x	x	x	x	x	x	36.308	37.45	-120.542	-119.224
	North Coast	Distributed_Solar_3	3_DS_1	349.9	fixed tilt		21.00%	x	x	x	x	x	x	37.248	38.435	-122.512	-121.706
	South Coast	Distributed_Solar_4	4_DS_1	349.9	fixed tilt		21.00%	x	x	x	x	x	x	33.631	34.278	-118.523	-117.067
	South Coast	Distributed_Solar_5	4_DS_2	349.9	fixed tilt		21.00%	x	x	x	x	x	x	32.661	33.32	-117.26	-116.781

Exhibit 3

CAISO 33% RPS Study Series
2020 Load Profile Parameters
High and Base Net Load Sensitivity 2011 Cases

Exhibit 3

CAISO 33% RPS Study Series
2020 Load Profile Parameters
High and Base Net Load Sensitivity 2011 Cases

Development of High and Base Net Load Sensitivity Profile for 2020 For Use in Analysis

Net Energy Calculations and Assumptions

Table 1 summarizes the assumptions for Gross Generation to be used in Base Load Case. This table is taken from the CEC's Form 1.2, Statewide Revised Demand Forecast Forms, Second Edition.

Table 1 Assumptions for Gross Generation to be used in Base Load Case

Year	Gross Generation	Non-PV & PV Self Generation	Net Energy For Load
2,020	341,778	14,896	326,882

The other adjustments made to the Total Generation to calculate the Total Net Energy to be used in the Load Profiles for Base Load and High Load cases are shown in Tables 2, 3, 4, and 5.

Table 2 Adjustments for Incremental Energy Efficiency for IOUs (CPUC's Technical Attachment V5)

	PG&E	SCE	SDG&E
Total Including Losses	**6,811**	**6,713**	**1,357**
Total	**6,214**	**6,286**	**1,267**
IOU Programs	2,805	3,599	722
Goals AB1109	846	613	169
Goals Standards	556	620	129
BBEES (Low)	754	916	177
Decay Replacement	1,253	538	70

The assumption for Line Loss factor Used in the above table is shown in Table 3

Table 3 Energy Efficiency (Line Loss Factors) (CPUC's Technical Attachment V5)

North	South	San Diego
9.6%	6.8%	7.1%

Energy Efficiency adjustments for Non-IOUs was calculating by subtracting the Decay Replacement component of EE savings for the IOUs and multiplying the resulting total for each IOU by 0.25. Table 4 summarizes the total EE related adjustments.

Table 4 Total Adjustments for Incremental Energy Efficiency (CPUC's Technical Attachment V5)

Total IOUs	Total Non- IOUs	Total EE Adjustment
14,881	3,214	18,095

The total adjustment for CHP is shown in Table 5.

Table 5 Total Adjustments for CHP (CPUC's Technical Attachment V5)

Year	Demand-side	Total including Losses
2020	7,556	8,198

The Net Energy to be used in the Base Load case is summarized in Table 6 and the Net Energy to be used in both Case Load case and High Load case is summarized in Table 7.

Exhibit 3

Table 6 Base Load Energy To Be Used in the Load Profiles

Case	Energy before adjustments(GWH)	Adjustments for PV behind the meter which will be modeled as generators (GW H)	Adjustments for Incremental EE (GWH)	Adjustments For Behind the Meter CHP (MW)	Adjustments for demand side (GWH)	Net Energy (GWH)
Base Load Case	326,882	(+) 3218	(-)18,095	(-)8,198	Assumed to have no energy impact	303,806

Table 7 Summary of Base Load and High Load Case Energy To Be Used in the Load Profiles

Case	Net Energy Load To BE Used in Profiling (GWh)
Base Load Case	303,806
High Load Case	334,187[1]

Peak Demand Calculations and Assumptions

According to CEC's 2009 IEPR, the maximum 2020 peak demand for the State of California is 70,964 MW[2] as shown in the following table.

CEC's 2020 Peak Demand from Tab Form 1.4

Year	Total End Use Load	Net Losses	Gross Generation	Non-PV Self Generation	PV Self Generation	Total Private Supply	Net Peak Demand
2020	67,993	5,716	73,709	1,935	810	2,745	70,964

[1] For High Load case, the net energy is assumed to be 110% of the net energy for Base Load case.
[2] Form 1.4, Second Edition, http://www.energy.ca.gov/2009_energypolicy/documents/, Statewide Revised Demand Forecast Forms

The "Net Peak Demand" was then adjusted to account for Incremental Energy Efficiency, EE (MW), Behind the Meter CHP (MW), Demand Response Programs, and PV Behind the Meter assumed for this project. These adjustments are explained in Tables 8, 9, 10, and 11. These three tables are taken from the CPUC's Technical Attachment Spreadsheet v5.xls.

Table 8 Assumptions Incremental Uncommitted EE (MW) for Year 2020 for IOUs (From CPUC Technical Attachment Spreadsheet v5.xls)

	PG&E	SCE	SDG&E
Total*	2,496	2,648	544
Total Before Line Loss	**2,275**	**2,461**	**496**
IOU Programs	853	951	270
Goals AB1109	119	93	23
Goals Standards	412	500	75
BBEES (Low)	648	792	114
Decay Replacement	243	125	14

* Totals are grossed up (by CPUC) to include line loss.

Table 9 Assumptions Incremental Uncommitted EE (MW) for Year 2020 (From CPUC Technical Attachment Spreadsheet v5.xls)

Total IOUs	Total Non- IOUs	Total EE Adjustment
5,687	1,318	7,005

Table 10 Assumptions Incremental Uncommitted DR (MW) for Year 2020 for IOUs (From Technical Attachment Spreadsheet v5.xls)

	PG&E	SCE	SDG&E
*Total DR**	313	14	0
Non-Event Based DR (PLS/TOU)	280	13	0

* Totals are grossed up to include line loss.

Table 11 Assumptions Incremental State-wide CHP (MW) (From Technical Attachment Spreadsheet v5.xls)

Year	Demand-side CHP (MW)	Total Including Losses (MW)
2020	936[3]	1,008

The peak demand to be used in the load profiles is shown in Table 12.

Table 12 Peak Demand To Be Used in the Load Profiles

Maximum Demand Before Adjustments (MW)	Adjustments For PV Behind the Meter (MW)	Adjustments For Incremental EE (MW)	Adjustments For Behind the Meter CHP (MW)	Adjustments For Demand Side Programs	Net Demand to be Profiled for Base Load Case (MW)	Net Demand to be Profiled for High Load Case (MW) (=Base Load *1.1)
70,964	(+)1,131	(-)7,005	(-)1,008	(-)327	63,755	70,131

Field Code Changed

Minimum Demand Calculations and Assumptions

Since minimum demand was not available, the minimum demand for the load profiles was calculated from the minimum demand used in previous study (CPUC 2009 Cases). For High Load case the minimum demand for the last study was 23,962 MW.

The calculation for minimum demand from previous demand is show n in Tables 13 for High Load Case and Base load case respectively.

[3] It is assumed that the supply side CHP will be modeled as generation in the Step 2 (Plexos) modeling.

Table 13 Calculation of Minimum Demand for High Load Case

Case	Peak Demand Used in 2010 Study (For High Load Case)	Peak Demand To be Used in 2011 Study	% reduction in Peak Demand	Assumed % change in Min. Demand (50 % of the change in Peak Demand)	Min. Demand Used in 2010 Study (for High Load Case)	Calculated Min. Demand for 2011 Study
Base Load Case	70,180	63,755	9.2%	4.6%	23,962	22,865
High Load Case	70,180	70,131	0.1%	0.05%	23,962	23,954

The minimum demand to be used in this study is shown in Table 14.

Table 14 Minimum Demand To Be Used in the Load Profiles

Case	Net Minimum Load To Be Used in Profiling (MW)
Base Load Case	22,727
High Load Case	23,801

Final 2020 Net High Load Profile Parameters

Table 15 Final 2020 Net High Load Profile Parameters

Year /Case	Peak (MW)	Energy(GW-hr)	Minimum(MW)
2020/Base	63,755	303,806	22,865
2020/High	70,131	334,187	23,954

Exhibit 3

Allocation of Energy and Demand to Production Simulation Bubbles

The methodology described below will be used unless there is more recent information from the CEC.

It is proposed to allocate the energy and demand on a pro-rate basis using the energy data in the CEC Spreadsheet CED 2010-2020 SumtoBubble Dated 10/20/2009 and with 52% of the PV energy for PV on the customer side of the meter to Northern California bubbles and the remainder to Southern California bubbles. These geographical allocation factors come from the PV energy analysis of the CEC contained in the file PV final IEPRo9 cappeak factors AT 10 14 09.xls.

Exhibit 4

California Energy Demand 2010 – 2020
Staff Forecast

California Energy Demand 2010-2020 Staff Revised Forecast

Summary by WECC Bubble

1-in-2 Net Peak Demand (MW)	2008	2009	2010	2011	2012	2013	2014	2015	2016	2017	2018	2019	2020	Average Annual Growth
PGE Bay	8,981	8,639	8,675	8,768	8,880	8,988	9,060	9,133	9,209	9,294	9,372	9,448	9,537	1.0%
PGE Valley	12,978	12,900	13,019	13,220	13,449	13,680	13,864	14,052	14,245	14,456	14,658	14,862	15,088	1.5%
TIDC	647	640	648	660	674	687	699	711	723	736	749	762	776	1.8%
SMUD/WAPA Control Area	4,552	4,512	4,541	4,604	4,684	4,764	4,830	4,892	4,950	5,009	5,068	5,130	5,196	1.4%
SCE TAC Area	22,558	23,248	23,479	23,785	24,142	24,518	24,823	25,149	25,482	25,833	26,169	26,509	26,875	1.4%
SDG&E	4,371	4,487	4,516	4,578	4,658	4,738	4,797	4,856	4,911	4,973	5,032	5,094	5,157	1.3%
Total LADWP Control Area	6,608	6,450	6,428	6,488	6,579	6,644	6,681	6,718	6,755	6,792	6,829	6,869	6,912	0.7%
Imperial Irrigation District	977	965	985	1,012	1,042	1,067	1,090	1,114	1,141	1,169	1,197	1,226	1,256	2.5%
Net Energy for Load (GWH)	2,008	2,009	2,010	2,011	2,012	2,013	2,014	2,015	2,016	2,017	2,018	2,019	2,020	
PGE Bay	47,244	45,025	45,044	45,450	45,989	46,583	46,956	47,322	47,703	48,122	48,503	48,876	49,269	0.9%
PGE Valley	61,482	61,506	61,788	62,545	63,446	64,479	65,266	66,050	66,863	67,739	68,583	69,431	70,322	1.3%
TIDC	2,694	2,615	2,631	2,668	2,718	2,768	2,804	2,841	2,879	2,919	2,959	2,999	3,041	1.5%
SMUD/WAPA Control Area	18,712	18,044	18,100	18,359	18,715	19,073	19,347	19,600	19,841	20,085	20,322	20,563	20,816	1.4%
SCE TAC Area	110,618	108,057	108,123	109,141	110,505	112,165	113,417	114,727	116,068	117,453	118,783	120,134	121,538	1.2%
SDG&E	22,085	21,599	21,695	21,941	22,284	22,680	22,978	23,283	23,556	23,845	24,130	24,434	24,740	1.3%
Total LADWP Control Area	30,604	29,644	29,523	29,814	30,309	30,707	30,968	31,214	31,461	31,697	31,939	32,186	32,437	0.9%
Imperial Irrigation District	3,712	3,692	3,763	3,857	3,969	4,077	4,169	4,265	4,369	4,479	4,590	4,705	4,828	2.5%
Load Factor														
PGE Bay	0.600	0.595	0.593	0.592	0.591	0.592	0.592	0.591	0.591	0.591	0.591	0.591	0.590	-0.1%
PGE Valley	0.541	0.544	0.542	0.540	0.539	0.538	0.537	0.537	0.536	0.535	0.534	0.533	0.532	-0.2%
TIDC	0.475	0.466	0.463	0.461	0.461	0.460	0.458	0.456	0.455	0.453	0.451	0.449	0.447	-0.4%
SMUD/WAPA Control Area	0.469	0.457	0.455	0.455	0.456	0.457	0.457	0.457	0.458	0.458	0.458	0.458	0.457	0.0%
SCE TAC Area	0.560	0.531	0.526	0.524	0.523	0.522	0.522	0.521	0.520	0.519	0.518	0.517	0.516	-0.2%
SDG&E	0.577	0.550	0.548	0.547	0.546	0.546	0.547	0.547	0.548	0.547	0.547	0.548	0.548	0.0%
Total LADWP Control Area	0.529	0.525	0.524	0.525	0.526	0.528	0.529	0.530	0.532	0.533	0.534	0.535	0.536	0.2%
Imperial Irrigation District	0.434	0.437	0.436	0.435	0.435	0.436	0.437	0.437	0.437	0.437	0.438	0.438	0.439	0.1%
Minimum (MW)														
PGE Bay	3,460	3,298	3,299	3,329	3,368	3,412	3,439	3,466	3,494	3,524	3,552	3,580	3,608	0.9%
PGE Valley	4,450	4,452	4,472	4,527	4,592	4,667	4,724	4,781	4,839	4,903	4,964	5,025	5,090	1.3%
TIDC	180	175	176	178	182	185	187	190	192	195	198	200	203	1.5%
SMUD/WAPA Control Area	1,277	1,231	1,235	1,253	1,277	1,302	1,320	1,338	1,354	1,371	1,387	1,403	1,421	1.4%
SCE TAC Area	8,335	8,142	8,147	8,224	8,327	8,452	8,546	8,645	8,746	8,850	8,950	9,052	9,158	1.2%
SDG&E	1,623	1,587	1,594	1,612	1,638	1,667	1,689	1,711	1,731	1,752	1,773	1,796	1,818	1.3%
Total LADWP Control Area	2,267	2,196	2,187	2,208	2,245	2,275	2,294	2,312	2,330	2,348	2,366	2,384	2,403	0.9%
Imperial Irrigation District	201	200	204	209	215	221	226	231	237	243	249	255	261	2.5%

Source: CALIFORNIA ENERGY DEMAND 2010-2020 STAFF REVISED FORECAST
October 2009, CEC-200-2009-012-
SF