Rulemaking No.: 13-12-010
Exhibit No.:
Witness: Dr. Shucheng Liu

Order Instituting Rulemaking to Integrate and Refine Procurement Policies and Consider Long-Term Procurement Plans.	)))	Rulemaking 13-12-010

PHASE I.A. DIRECT TESTIMONY OF DR. SHUCHENG LIU ON BEHALF OF 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 13-12-010

PHASE I.A. DIRECT TESTIMONY OF DR. SHUCHENG LIU ON BEHALF OF THE CALIFORNIA INDEPENDENT SYSTEM OPERATOR CORPORATION

I. BACKGROUND

Q. What is your name and who is your employer?

A. My name is Shucheng Liu and I am employed by the California Independent System Operator Corporation (CAISO) as Principal, Market Development.

Q. Please describe your educational and professional background.

A. I am the Principal, Market Development of the CAISO in the Market Quality and Renewable Integration Division. Over the past three years I have led the CAISO renewable integration study supporting the CPUC Long-Term Procurement Plan (LTPP) proceeding.

Prior to joining the CAISO in 2007, I held various positions with BMC Consulting, Henwood Energy Services, Navigant Consulting, and Global Energy Decisions consulting for the electricity industry.

I received a B.S. degree in Nuclear Engineering and an M.S. in Management Science from Tsinghua University of China, an M.S. and a Ph.D. in Engineering-Economic Systems and Operations Research from Stanford University.

Q. What is the purpose of your testimony?

A. I describe the CAISO's 2014 LTPP deterministic study, including the overall structure, methodologies, assumptions, and key results, of four renewable portfolio scenarios and one sensitivity case described in the February 27, 2014 Assigned Commissioner Ruling (ACR). Specifically, the CAISO analyzed the Trajectory, High Load, Expanded Preferred Resources, and 40% RPS in 2024 scenarios. Consistent with the ACR, the CAISO also conducted an additional sensitivity study that consists of the Trajectory scenario without the Diablo Canyon facility. For the purposes of this testimony, I will refer to all of these scenarios and sensitivity cases as "scenarios." Consistent with the ACR directives, the CAISO conducted ten year studies focusing on grid needs in 2024.

Q. How has the CAISO participated in this proceeding?

A. The CAISO worked closely with the Energy Division staff and staff from the California Energy Commission (CEC) in developing the planning assumptions and scenarios that these agencies presented to the parties at a workshop held at the Commission on December 18, 2013. Since that time, the CAISO presented information about study methodologies and assumptions at the April 24 and June 6, 2014 workshops. The CAISO posted its datasets for the studies described in this testimony on our ftp, as this information became available, and shared preliminary results from the trajectory scenario studies with the advisory group on July 29, 2014.

Q. Please describe how your testimony is organized.

A. First, I provide an overview of the CAISO's LTPP study and describe the scenarios the CAISO considered, including how the CAISO modeled the input assumptions for each scenario. Second, I provide background information on the study methodologies the CAISO uses to conduct its system flexibility study. Finally, I summarize the study results for each scenario and describe next steps in the CAISO's study process.

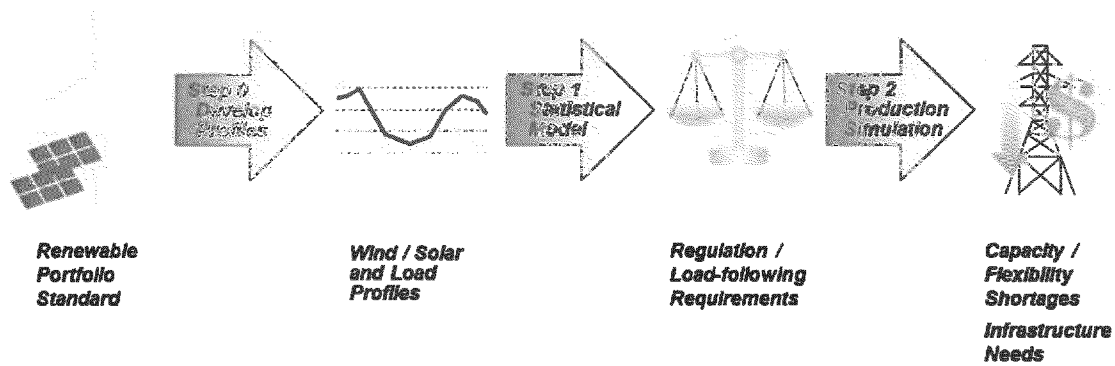
CAISO witness Dr. Karl Meeusen provides policy conclusions and recommendations based on these study results in his testimony.

II. OVERVIEW OF THE CAISO LTPP STUDY

Q. Please provide an overview of the CAISO LTPP study?

A. The CAISO LTPP study is divided into three steps: Steps 0, 1, and 2. In Step 0, the CAISO developed load, wind, and solar profiles, based on the load forecast and resource assumptions provided by the Commission for each scenario. In Step 1, the CAISO conducted the statistical analysis to calculate regulation and load following requirements using the profiles developed in Step 0. In Step 2, the CAISO conducted the production simulation using the requirements derived in Step 1, along with the hourly profiles from Step 0 and other operating reserves (spinning and non-spinning). Figure 1 shows the key steps of the study process

Figure 1: The CAISO LTPP Study Process



Q. What modeling tools and resources did you use to conduct the study?

A. In the Step 1 analysis, the CAISO used a statistical analysis tool developed by the Pacific Northwest National Laboratories' (PNNL). For Step 2, the CAISO used Energy Exemplar's PLEXOS production simulation package and also consulted with Energy Exemplar to develop the models and run production simulations.

Q. Please describe the scenarios the CAISO studied.

A. The February 27, 2014 ACR defined five planning scenarios and one sensitivity case for system flexibility study. The scenarios are Trajectory, High Load, Expanded Preferred Resources, 40% RPS in 2024, and High Distributed Generation (DG). Consistent with the ACR the CAISO also conducted an additional sensitivity case, which consists of the Trajectory scenario without the Diablo Canyon nuclear plant.

The Trajectory scenario is a conservative expected scenario using system planning assumptions that are common to both the CAISO LTPP and Transmission Planning P.(TPP) studies. It includes 1-in-2 peak load assumption and mid energy use forecast, and 33% Renewable Portfolio Standard (RPS). The scenario assumes there is little change in existing policies.

The High Load scenario is essentially the same as the Trajectory scenario except that it has high energy use forecast.

The Expanded Preferred Scenario has the same assumptions as the Trajectory scenario but includes a higher RPS requirement -- 40%. This scenario also includes more Additional Achievable Energy Efficiency (AAEE), behind the meter customer Photo Voltaic (PV), and Combined Heat and Power (CHP) resources. According to the ACR this scenario best reflects achievement of the State's preferred resources policies.

The 40% RPS in 2024 scenario also consists of the Trajectory scenario, with a 40% RPS assumption. It assumes a high penetration of large central station renewables.

Given timing constraints, the CAISO worked closely with the CPUC and CEC staff to determine four scenarios (Trajectory, High Load, Expanded Preferred Resources, 40% RPS in 2024) and one sensitivity case (Trajectory scenario without Diablo Canyon) that CAISO would study in LTPP phase 1a.

III. STUDY METHODOLOGIES – STEP 0 AND 1

Q. What is the purpose of Step 0?

A. The purpose of Step 0 is to create full-year hourly and 1-minute chronological profiles for California loads and solar and wind generation. First, the CAISO created hourly profiles and then created 1-minute profiles based on the hourly profiles using different methodologies for load, solar, and wind. A more detailed discussion of the Step 0 methodologies is available in a report that the CAISO published on its website at http://www.caiso.com/282d/282d85c9391b0.pdf.

Q. What inputs did you use to create the 2014 LTPP study Step 0?

A. For each scenario, the CAISO created the hourly load profiles for each of the modeling zones (see discussion about zones below) based on the adjusted load forecasts in the CPUC LTPP scenario definition and the 2005 actual load shapes.

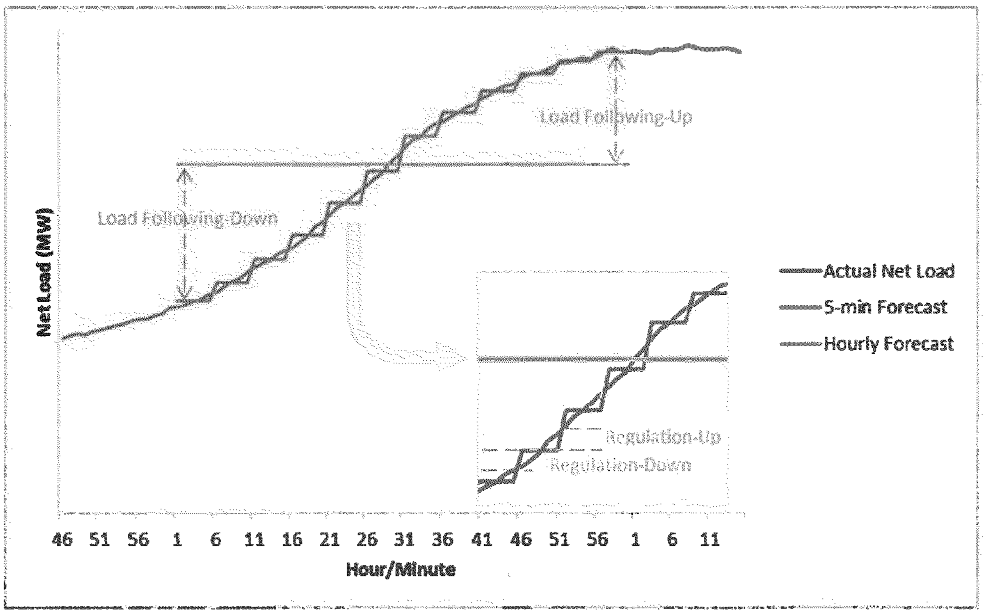
The LTPP scenario definition, specifically the RPS Calculator, provided location, quantity, and capacity factor information for each of the new RPS projects in each scenario. The CEC provided this information for existing RPS projects. The LTPP scenario definition also specified the amount of customer photo voltaic to consider because these are not considered RPS resources. The base shapes of the generation profiles, which are based on 2005 weather conditions, were from the TEPPC 2024 Common Case (version updated on May 12, 2014). The CAISO created the hourly solar and wind generation profiles based on this information for the various projects and aggregated profiles by technology and by zone and included the customer photo voltaic resources in the solar profiles.

Q. How did you calculate regulation and load following requirements in Step 1?

A. Step 1 mimics the effect of variability and uncertainty between the CAISO scheduling process, which moves from hourly schedules in the day-ahead and hour-ahead markets, to the 5-min real-time dispatch process in the real-time market, and then to actual operations. The Step 1 process produced the regulation and load following requirements that provide the capacity headroom needs to be reserved in the hourly production simulation in Step 2 (see discussion below).

In hourly scheduling, the CAISO commits and dispatches generation resources economically to meet hourly average net load (native load minus solar and wind generation) based on forecast. The hourly schedules should also reserve sufficient upward and downward ramping headroom for the CAISO to use in real-time dispatch within the hour. In the real-time dispatch, the CAISO dispatches generation resources economically to meet the 5-minute average forecasted net load, which is usually different than the hourly forecasted net load. The ramping headroom reserved in the hourly schedules must be sufficient to cover the maximum net load difference between 5-minute and hourly forecasts within the hour. The headroom in the model is called load following capacity. In operation the actual net load changes constantly. The CAISO must balance Load's deviation from the 5-minute schedules using regulation reserve. Regulation requirements should be able to cover the largest deviation for each 5-minute interval. Figure 2 illustrates the concepts of load following and regulation requirements without forecast errors.

Figure 2: Illustration of Regulation and Load Following Requirements



Q. Please describe the Step 1 process.

Step 1 is a stochastic process that considers random forecast errors in load, solar and wind generation. With forecast errors, the 5-minute and hourly forecasts are not the averages of actual net load, but vary independently around the average of actual net load. The CAISO conducted Monte Carlo simulations using the PNNL statistical tool to calculate the requirements for regulation and load following. The final (deterministic) requirements were determined based on the probability distribution of the simulation results. The Step 1 methodologies are discussed in detail in the CAISO report at http://www.caiso.com/282d/282d85c9391b0.pdf.

Q. What were the inputs for Step 1?

A. In Step 1 the CAISO used the 1-minute profiles created in Step 0 and forecast errors.

Q. What Step 1 assumptions were specific to the studies conducted in this 2014 LTPP compared to studies in prior years?

A. The CAISO changed the following Step 1 assumptions in the 2014 LTPP study.

- Changed the Trading Hour (T)-1 hour forecast errors to T-30 minute forecast errors.

- Changed the assumptions about out-of-state RPS resource characteristics, as shown in Table 1.
  - RPS resources with dynamic schedules may change output minute by minute, same as the resources in California. Their forecast errors are considered in Step 1..
  - Resources with 15-minute schedule have output fixed over 15 minutes. The CAISO assumed they would not have any forecast error.
  - The CAISO did not include resources with hourly schedules or unbundled Renewable Energy Credits (RECs) in Step 1 calculation.

Table 1: Assumptions about Out-of-State RPS Resources Import Scheduling

LTPP Study	Dynamic Schedule	15-min Schedule	Hourly Schedule	Unbundled RECs
2014	15%	35%	20%	30%
2010	15%	15%	40%	30%

Q. What were the forecast errors used?

A. Table 2, Table 3 and Table 4 show load, solar, and wind forecast errors, respectively, used in the Step 1 calculation. Solar and wind forecast errors were calculated based on the profiles of each of the four scenarios.

Table 2: Load Forecast Errors (standard deviation, MW)[1]

Scenario	Load	Time	Hour	Spring	Summer	Fall	Winter
All	RTPD	t-30 min	All	228	333	410	252
All	RTD	t-5 min	All	103	189	258	118

Table 3: Solar Forecast Errors[2]

Scenario	Type	Persistent	Hour	0<=CI<0.2	0.2<=CI<0.5	0.5<=CI<0.8	0.8<=CI<=1
Trajectory	DG PV	t-30 min	H12-16	1.12%	1.92%	1.85%	0.95%
Trajectory	Small PV	t-30 min	H12-16	1.16%	1.99%	1.79%	0.96%
Trajectory	Large PV	t-30 min	H12-16	1.54%	3.08%	2.81%	1.39%
Trajectory	Solar Thermal	t-30 min	H12-16	2.91%	6.33%	5.96%	2.33%
High Load	DG PV	t-30 min	H12-16	1.12%	1.92%	1.85%	0.95%
High Load	Small PV	t-30 min	H12-16	1.30%	1.81%	1.70%	0.95%
High Load	Large PV	t-30 min	H12-16	1.27%	2.51%	2.26%	1.13%
High Load	Solar Thermal	t-30 min	H12-16	2.84%	6.18%	5.82%	2.27%
Expanded Preferred Resources	DG PV	t-30 min	H12-16	1.12%	1.91%	1.84%	0.95%
Expanded Preferred Resources	Small PV	t-30 min	H12-16	1.08%	2.13%	1.87%	0.98%
Expanded Preferred Resources	Large PV	t-30 min	H12-16	2.16%	4.34%	3.98%	1.97%
Expanded Preferred Resources	Solar Thermal	t-30 min	H12-16	3.08%	6.69%	6.30%	2.46%
40% RPS in 2024	DG PV	t-30 min	H12-16	1.12%	1.91%	1.84%	0.95%
40% RPS in 2024	Small PV	t-30 min	H12-16	1.05%	2.08%	1.83%	0.96%
40% RPS in 2024	Large PV	t-30 min	H12-16	1.28%	2.58%	2.37%	1.17%
40% RPS in 2024	Solar Thermal	t-30 min	H12-16	2.84%	6.18%	5.82%	2.27%

Table 4: Wind Forecast Errors

Scenario	Type	Persistent	Hour	Spring	Summer	Fall	Winter
Trajectory	Wind	t-30 min	All	1.86%	1.59%	1.67%	2.03%
High Load	Wind	t-30 min	All	1.79%	1.53%	1.61%	1.96%
Expanded Preferred Resources	Wind	t-30 min	All	2.02%	1.72%	1.81%	2.21%
40% RPS in 2024	Wind	t-30 min	All	1.79%	1.53%	1.60%	1.95%

Q. Can you provide a summary of the regulation and load following requirements calculated in Step 1?

A. Yes. These requirement values vary from hour-to-hour, day-to-day. The only statistics that may be meaningful to show here are the maximum values, which define the upper boundaries of the requirements. Table 5 provides the monthly maximum values of CAISO regulation and load following requirements. As you can see from the table, the regulation and load following requirements in the

[1] Load forecast errors were calculated based on the CAISO 2012 operation data.
[2] "CI" is clearness index

summer months are lower than other months because renewable generation tends to be less volatile in the summer.

Table 5: Maximum CAISO Regulation and Load-Following Requirements

(MW)	1	2	3	4	5	6	7	8	9	10	11	12	Annual
Trajectory													
Regulation Up	480	481	423	416	411	564	558	575	792	803	796	481	803
Load Following Up	2,336	2,246	2,422	2,190	2,056	1,922	1,967	2,053	2,517	2,552	2,573	2,320	2,573
Regulation Down	551	554	743	651	688	647	688	690	995	1.109	915	540	1,109
Load Following Down	2,535	2,451	2,127	2,119	2,087	1,959	1,948	1,962	2,643	2,646	2,669	2,521	2,669
High Load													
Regulation Up	505	508	431	430	433	600	595	624	872	886	836	485	886
Load Following Up	2,326	2,296	2,579	2,312	2,270	2,083	2,089	2,269	2,571	2,697	2,613	2,329	2,697
Regulation Down	568	579	806	729	805	657	714	717	1,030	1,162	958	568	1,162
Load Following Down	2,521	2,516	2,286	2,290	2,282	2,056	2,078	2,077	2,860	2,892	2,874	2,526	2,892
Expanded Preferred Resources													
Regulation Up	516	512	462	463	464	627	620	665	911	929	838	495	929
Load Following Up	2,428	2,448	3,066	2,679	2,631	2,197	2,516	2,517	3,155	3,225	3,206	2,445	3,225
Regulation Down	611	608	804	755	801	702	878	827	1,092	1,182	1,091	611	1,182
Load Following Down	2,800	2,764	2,599	2,566	2,597	2,327	2,458	2,461	3,087	3,135	3,127	2,766	3,133
40% RPS in 2024													
Regulation Up	578	583	502	503	503	639	640	712	1,026	1,026	907	557	1,026
Load Following Up	2,734	2,702	3,483	3,113	3,015	2,448	2,779	2,885	3,490	3,532	3,482	2,740	3,532
Regulation Down	694	691	1,042	900	1,038	745	893	865	1,234	1,413	1,136	693	1,413
Load Following Down	3,101	3,081	2,838	2,849	2,806	2,631	2,545	2,626	3,415	3,529	3,519	3,095	3,529

IV. STUDY METHODOLOGIES – STEP 2

Q. Please describe how the production simulation analysis in Step 2 evaluates the sufficiency of system capacity and flexibility?

A. In the Step 2 production simulation, the CAISO used a WECC-wide model. The CAIOS's analysis mimicked the methodologies implemented in the CAISO market and operational practices for enforcing operational constraints, including chronological simulation with minimum-cost optimization, unit commitment, time-based ramping limitations, minimum up and down time, start-up and shut-down time, random forced outages and planned maintenance outages, etc.

The simulation co-optimizes for energy, ancillary services, and load following requirements to achieve minimum cost solutions. The simulation captures shortfalls when there is insufficient capacity or flexibility to meet the load, ancillary service, and load following requirements. The simulation reports such shortfalls in detail, by category. In particular, it identifies what product is short (*e.g.*, load following, ancillary services, or energy); the level of the shortfall; and, what caused the shortfall. This information is also useful for evaluating solutions to the shortfalls.

Q. What optimization methodology does the production simulation model use?

A. The model uses Mixed-Integer Linear Programing (MIP) optimization for unit commitment and dispatch. The simulation runs chronologically to co-optimize generation dispatch, ancillary services and load following requirements, subject to various operational and availability constraints. The outcome of the co-optimization is a least-cost solution that meets load, ancillary service and load following requirements simultaneously. When there is insufficient capacity or flexibility to meet one or more of the requirements, the optimization captures and reports the shortfalls. The chronological simulation can run in hourly or sub-hourly intervals; although, the CAISO's study only conducted hourly simulations.[3]

Q. How does the simulation capture system capacity shortfalls?

A. In the simulation, shortfalls occur when supply is insufficient to meet the combination of load, ancillary services, and load following requirements. If all available resources, including demand response and import capability, are depleted during these hours, the shortfalls are capacity shortfalls since there is no more capacity available for use. Alternatively, there are cases in which there is still unused capacity available but that capacity is not capable of following load ramp. These are referred to flexibility shortfalls.

A shortfall may occur either in meeting ancillary service or load following requirements, or in meeting load. The model sets a priority order for shortfall, similar to that in the CAISO market scarcity pricing mechanism. The order from

[3] 5-min chronological simulation was conducted using the model in the study for the CPUC 2010 LTPP proceeding.

high to low is energy, regulation-up, spinning, non-spinning, and load following-up on the upward side, and dump power, regulation-down, and load following-down on the downward side. That means when there is an upward shortfall, the shortfall occurs first in load following-up. If the shortfall is large enough, it will spill over to non-spinning, spinning, regulation-up and finally to unserved energy (loss of load).

Q. Can the simulation capture system flexibility shortfalls?

A. Flexibility shortfalls occur mostly when the system net load has fast ramping in either upward or downward direction. The fast ramping is usually caused by the intermittencies and special patterns of renewable generation. If the renewable generation is dispatchable (or curtailable) the net load curve may be balanced. The requirement for system flexibility is significantly reduced and a flexibility shortfall may not occur at all, depending on the level of renewable generation that can be curtailed. Thus, there is a trade-off between the dispatchability of renewable generation and requirements for system flexibility.

In the 2014 LTPP Phase 1a study, the CAISO assumed that all the California RPS solar and wind generation is curtailable, based on the guidance from the CPUC. Therefore the production simulation was not able to capture flexibility shortfalls. Further studies may be needed in 2014 LTPP Phase 1b to explore the interplay between renewable dispatchability and system flexibility requirements to ensure that if a sufficient quantity of dispatchable renewables does not materialize, a flexibility shortage does not result.

Q. Please describe the structure of the production simulation model.

A. The production simulation model is a WECC-wide zonal model. There are 25 zones in total; eight in California divided by planning areas. The California zones are Imperial Irrigation District (IID), Los Angeles Department of Water and Power (LADWP), PG&E_Bay Area, PG&E_Valley, SCE, SDG&E, Sacramento Municipal Utility District (SMUD), and Turlock Irrigation District (TIDC).

The zones are connected through transmission paths. The transmission limits (path ratings) between zones, in both directions, are enforced. The transmission limits between any two adjacent zones reflect the maximum simultaneous transfer capabilities between the two zones. The zonal model assumes no transmission limits within each zone. This does not mean there are no transmission constraints within a zone. Such constraints may require local resources to be committed and dispatched and the zonal model does not capture this requirement. Such a requirement for local resources may exacerbate the over-generation conditions and quantity curtailment.

There is a wheeling charge for each direction on each transmission path. It reflects the Transmission Access Charge and transmission loss of energy (in financial term). The study did not model transmission loss quantities (MWh) explicitly, but it assumed they wereincluded in the load forecasts.

Each zone has a full-year chronological load profile. Some California zones have an additional profile for pump load. The zones also have ancillary services and load following requirements, either as fixed profiles or a certain percent of their loads. Some zones share ancillary services and load following requirements. For example, the CAISO has total ancillary service and load following requirements for PG&E, SCE, and SDG&E together. The California municipals (IID, LADWP, SMUD, and TIDC) also share ancillary service and load-following requirements.

The load of a zone can be met by local generation plus import. The ancillary service and load following requirements can be met by local resources and from resources outside the zone as designated in the model. A resource can provide ancillary services and load following only to one designated zone or zones sharing ancillary services and load-following requirements.

Q. What transmission related constraints did you model?

A. Besides the transmission paths as described above, the model also enforced the following additional transmission related constraints: the Southern California Import Transmission (SCIT) and California import limits; the CAISO zero net export limit; and local generation requirement constraints.

Q. How are the SCIT and California import limits determined?

A. The CAISO and SCE developed a tool a few years ago to assess the simultaneous import capability of the SCIT area (in the model the SCIT area includes LADWP, SCE, and SDG&E) reflecting the Southern California nomogram constraint. The tool also calculates total California simultaneous import capability. The tool was updated with the assumptions of each of the four scenarios in this study.

All energy imports plus the ancillary services provided by out-of-state resources are subject to the California import limits.

Q. Why did the CAISO implement a zero net import limit in the studies?

A. This limit restricts the CAISO from net exporting in any given hour. It impacts the system only when there is over-generation in the CAISO. For the purpose of this study, the CAISO imposed this limit because, .

historically, the CAISO has never been a net exporter of energy even during times over-generation conditions were occurring. Rather, the CAISO's lowest net import has been about 2,000MW. In part the CAISO remains a net importer of energy because there are some dedicated dynamic imports from out-of-state RPS renewable resources and from some out-of-state non-RPS resources owned by the California investor owned utilities.

In the CAISO market, imports and exports schedules are mostly established in the day-ahead market. Moving into the real-time market, forecasts become more accurate, but the CAISO observes limited movement of import and export schedules from the day-ahead level, even when the CAISO energy prices go to negative. In other words, imports and exports do not always respond to real-time prices, and this often results in excessive imports.

One major cause of this phenomenon may be the lack of a west-wide jointly cleared day-ahead market. The CAISO usually does not detect over-generation in the day-ahead market, in part because not all supply is being scheduled in the day-ahead. When additional supply is delivered in the real-time market, the price starts to become negative reflecting over-generation conditions. At that time, only the market participants offering to back off from their day-ahead schedules or willing to consume more, help relieve the over-generation conditions. In real-time neighboring balancing authority areas have limited ability to back or decommit resources. Indeed, neighboring balancing areas may be also experiencing over-generation. The Energy Imbalance Market (EIM) is a positive step because it helps facilitate neighboring balancing authority areas to absorb over-generation based on the real-time imbalance and pricing conditions. However, the EIM still has limited capability to address over-generation because it cannot decommit long start resources that have already been committed through neighboring balancing areas day-ahead operational planning process. Ideally there should be a west-wide jointly cleared market with both day-ahead and real-time scheduling processes. That could produce a coordinated resource plan recognizing forecasted renewable supply. Such a west-wide coordinated approach would greatly improve the capability to address over-generation and potentially mitigate renewable generation curtailment issues.

Q. What are the regional generation requirement constraints?

A. The balancing area generation constraint requires at least 25% of load to be met by generation from local resources (except renewable, demand response, and battery storage). This constraint applies to the CAISO, IID, LADWP, SCE, SDG&E, SMUD, and TIDC.

The constraint is necessary for the balancing authority to comply with the NERC control performance standards. A balancing authority must have at least 25% of its internal generation on-line with adequate available capacity for dispatch or risk non-compliance. Within the CAISO's footprint, a contingency that results in the tripping of Path 26 would separate the north from the south. Without a minimum amount of generation in southern California, there is a risk that the CAISO could completely lose the load if Path 26 were to open. Similarly, if the ties between SDGE and SCE were to open, there is a risk of losing SDGE's load.

Q. What is a "dedicated import"?

A. Dedicated import is must-take import. Dedicated imports include two categories. The first is the import of 70% generation by the out-of-state RPS renewable resources. California parties own portions of some out-of-state non-renewable resources, such as Hoover, Palo Verde, etc. The other category of dedicated import is the import of generation by these resources that belongs to the California parties.

Q. How did you model thermal resources?

A. We modeled thermal resources with all characteristics. The characteristics include maximum and minimum capacity, minimum up/down time, start-up and shut-down time, heat rate and fuel, variable operations and maintenance (VOM) cost, start-up cost, maintenance outage rate and forced outage rate, etc. The operation of a thermal resource is constrained by the characteristics.

Forced outages of each resource are generated randomly using uniform distribution function and the forced outage rate of the resource. Maintenance outages are generated with consideration of seasons, time-of-day, system supply and demand situation, minimum time to repair, etc. High load months have significantly fewer maintenance outages than other months.

When the resource is dispatched below its minimum capacity during start up, it can produce energy, but cannot provide ancillary services or load following. When the resource is dispatched above minimum capacity, the resource may be able to provide ancillary services and load following, but is subject to the ramping constraints. That is, in upward direction, its total provision of ancillary services cannot exceed its 10-minute ramping capability (10 minutes times ramp rate) and unused capacity; total provision of ancillary services and load following cannot exceed its 20-minute ramping capability and unused capacity; and the sum of energy ramping and provision of ancillary services and load following cannot exceed its 60-minute ramping capability and unused capacity. In the downward direction, dispatch above its minimum capacity limits the resource's provision of regulation-down and load following-down.

Q. How did you model renewable resources?

A. We modeled all renewable resources, except the solar thermal plant with storage, with hourly generation profiles. The generation of some solar and wind resources may be curtailed in the simulation (see discussion below). The solar thermal plant with storage also has an hourly profile as its energy source from the collectors. Its dispatch can be controlled with its storage capability. The hourly profiles of solar and wind were created in Step 0. The profiles of other renewable resources, such as geothermal, biogas, etc., are constant from hour-to-hour.

Renewable resources cannot provide ancillary services or load following, but can be disptachable (through curtailment). The study assigned a -$300/MWh cost to the California RPS solar and wind resources. When there is over-generation that pushes energy price down to -$300/MWh, these solar and wind resources will be curtailed.

For RPS resources located outside California, the study modeled 70% of their generation as dedicated import.

Q. How did you model hydro and pumped storage resources?

A. There are two types of hydro resources. Run-of-river hydro resources each has a fixed generation profile equal to actual generation in 2005. These resources cannot provide ancillary services or load following. Dispatchable hydro resources have minimum and maximum capacities. Each of the resources has a weekly energy limit equal to its weekly generation in 2005. In the simulation, the weekly energy is first allocated to each day in the week through an initial run. Then the resource is dispatched optimally in each day with the energy limit. Dispatchable hydro resources can provide ancillary services and load following. The hydro resources were aggregated by zone in the model. They do not have outages since the outages were reflected in the 2005 actual hydro generation already.

Pumped storage resources' pumping and generation schedules are optimized with constraints on capacity, water inflow, reservoir storage volume (for some resources the water level specified for the beginning of each month) and pumping efficiencies. In generation mode, pumped storage resources can provide all ancillary services and load following. Some new pumped storage resources with variable speed pumps can also provide ancillary services and load following in pumping mode. Pumped storage resources are modeled individually. They have forced and maintenance outages.

Q. How did you model other storage resources?

A. We modeled new California energy storage target resources, except pumped storage, as battery storages. Battery storage can provide ancillary services, and load following in both charging and discharging modes if it is connected to the transmission or distribution network. The CAISO implemented a round-trip efficiency for each of the storage resources.

Q. How did you model demand response resources?

A. We modeled demand response resources with high triggering prices. When the energy price reaches the triggering price, the demand response resources' loads are dropped. The triggering prices are high enough so that the demand response resources will not be triggered more frequently than is realistic. Some demand response resources have a monthly energy limit representing how many hours the resources can be triggered in a month. In the model, demand response resources cannot provide ancillary services or load following in the model.

Q. How did you model CO2 emission?

A. We assigned a fuel to each fossil generation resource. Each fuel has a CO2 emission rate. Therefore, the total emission of a fossil generation resource is the sum of the hourly product of the resource's total generation, heat rate, and the fuel's emission rate for the year hours.

In the model, there is a CO2 emission price. In California, the emission cost per MWh (emission price times heat rate times emission rate of the fuel) is added to the fossil generation resource's variable cost. For fossil generation resources outside California, the study did not add the emission cost to their generation variable cost. Instead, the study added a CO2 emission cost adder, calculated based on the emission price and average generation emission rate, to the wheeling rate on all import paths of California. All imports, except the California dedicated imports, are subject to the CO2 emission cost adder.

V. DATA SOURCES AND MODELING ASSUMPTIONS

Q. What are the sources of data for this study?

A. There are several data sources for this study. Figure 3 shows the main sources.

The CEC IEPR forecasts provided load forecast and other load adjustments, including AAEE, customer photo voltaic, demand-side CHP, and pump load. IEPR forecasts also provided natural gas prices and CO2 emission price forecasts.

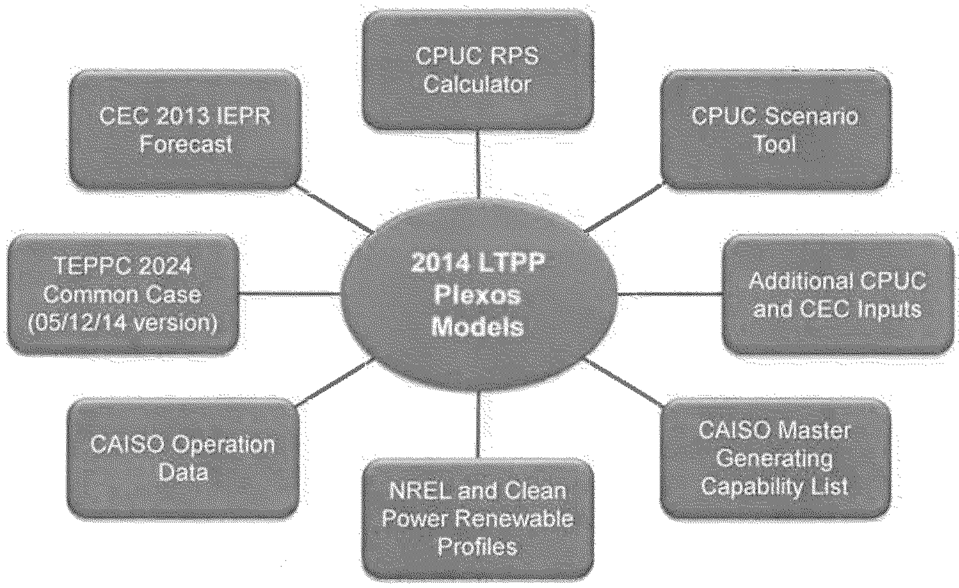
The CPUC RPS Calculator has project specific information for the new RPS resources. The CEC provided existing RPS resource information.

Conventional generation resource information came from the CPUC Scenario Tool and the CAISO Master Generating Capacity List (for the CAISO resources), as well as the TEPPC 2024 Common Case (version updated on May 12, 2014, for the rest of WECC).

The TEPPC Common Case also provided prices of fuels except natural gas, path rating and wheeling rates for the whole WECC, load, ancillary services and flexibility reserve requirements for the zones outside California. All renewable generation profiles were from the Common Case.

The information about demand response programs and storage modeling assumptions came from the CPUC.

Figure 3: Data Sources for the CAISO 2014 LTPP Study



Generation resources ramp rates were calculated based on the CAISO Master File data; forced and maintenance outages rates were calculated based on the CAISO 2006-2010 operation data. California pump load shapes were developed based on the CAISO 2009-2011 operation data.

NREL and Clean Power Research provided multi-year simulated historical solar and wind generation profiles for developing stochastic model.

Q. What are the aggregated supply and demand assumptions for each studied scenario?

A. Table 7 shows load forecasts, load adjustments, new resource additions and resource retirements for the CAISO. The planning reserve margin (PRM) ranges from 117% for the High Load scenario to 141% for the Expanded Preferred Resources scenario. The PRMs were calculated based on the net qualified capacity (NQC). The NQC for renewable resources may not accurately reflect the resources' output during high load hours.

Table 6: CAISO 2024 Aggregate Supply and Demand Forecast[4]

CAISO-2024	Trajectory	High Load	Expanded Preferred Resources	40% RPS in 2024
Demand (MW) *				
IEPR Net Load	56,044	59,006	56,044	56,044
AA-EE	5,042	5,042	8,286	5,042
Managed Demand Net Load	51,003	53,964	47,758	51,003
BTM resources modeled as Supply (MW)				
1: Inc. Small PV	0	0	1,647	0
2: Inc. Demand-side CHP	0	0	1,832	0
Supply (MW)				
3: Existing Resources	51,878	51,878	51,878	51,878
4: Resource Additions	7,468	8,440	9,202	11,754
Non-RPS (Conventional Expected)	329	329	329	329
RPS	5,939	6,911	7,673	10,225
Authorized Procurement	1,200	1,200	1,200	1,200
5: Imports	13,396	13,396	13,396	13,396
6: Inc. Supply-side CHP	0	0	0	0
7: Dispatchable DR	2,176	2,176	2,176	2,176
8: Energy Storage Target	913	913	913	913
9: Energy Storage Other	0	0	0	0
10: Resource Retirements	13,708	13,708	13,708	13,708
OTC Non Nuclear	11,685	11,685	11,685	11,685
OTC Nuclear	0	0	0	0
Solar + Wind	0	0	0	0
Geothermal + Biomass	0	0	0	0
Hydro + Pump	0	0	0	0
Other (non-OTC thermal/cogen/other)	2,023	2,023	2,023	2,023
Net Supply = sum[1:9] - 10	62,122	63,094	67,335	66,408
Planning Reserve Margin	22%	17%	41%	30%

Please also note that the table includes only 913 MW of the new energy storage target. However, the CAISO's model actually includes all 1,285 MW of new storage (1,325 minus 40 MW of the Lake Hodges pumped storage resource).

Q. How did you adjust the load forecasts?

A. We adjusted the load forecast from the CEC IEPR forecasts according to the scenario definitions.

Each scenario has certain amount of AAEE not included in the IEPR load forecast. The amount of AAEE was treated as reduction to peak load and energy forecasts.

[4] Data is from the CPUC Scenario Tool.

The IEPR forecasts embed the impact of behind-the-meter customer photo voltaic. To model it more accurately, the customer photo voltaic was removed from load forecasts and modeled as supply resources with fixed generation profiles. Load forecast were adjusted up accordingly based on the peak load impact of the customer photo voltaic.

We also removed pump load embedded in IEPR forecast from the forecasts and modeled it as separate load with profiles developed based on the CAISO 2009-2011 operation data.

Table 7 shows the load adjustments for the trajectory scenario. The adjustments for other scenarios are included in the Appendix.

Table 7: The CAISO 2024 Load Adjustment for Trajectory Scenario

Trajectory	Load Forecast*	AAEE**	Embedded Small PV**	Pumping Load**	Total Load
Load Forecast (MW)					
IID	1,241	0	0	0	1,241
LDWP	7,208	0	0	0	7,208
PG&E_BAY	9,614	-998	499	0	9,115
PG&E_VLY	15,569	-1,292	646	-614	14,308
SCE	26,882	-2,308	732	-421	24,885
SDGE	5,357	-567	251	0	5,041
SMUD	5,240	0	0	-143	5,097
TIDC	721	0	0	0	721
CAISO	**57,422**	**-5,165**	**2,127**	**-1,035**	**53,349**
CA	**71,833**	**-5,165**	**2,127**	**-1,178**	**67,617**
Load Forecast (GWh)					
IID	4,777	0	0	0	4,777
LDWP	32,618	0	0	0	32,618
PG&E_BAY	51,511	-4,134	1,696	0	49,073
PG&E_VLY	68,832	-5,767	2,366	-4,556	60,875
SCE	119,137	-10,239	2,696	-5,700	105,894
SDGE	24,271	-2,425	958	0	22,805
SMUD	20,117	0	0	-1,455	18,662
TIDC	2,978	0	0	0	2,978
CAISO	**263,751**	**-22,565**	**7,716**	**-10,256**	**238,646**
CA	**324,241**	**-22,565**	**7,716**	**-11,711**	**297,681**

* CEC 2014 IPER Form 1.5a and 1.5b. All scenarios have Mid (1-in-2) except High Load scenario, which has High (1-in-2) forecast
** CEC 2014 IPER

Q. Please describe the Renewable Net Short for each scenario and how you calculated that number.

A. Each of the scenarios needs to meet a specific RPS goal (33% or 40%). The renewable energy needed for RPS goals is calculated based on statewide electricity retail sales, not the forecasted load modeled.

Behind-the-meter customer photo voltaic does not count toward meeting the RPS goals. The calculation was done in the CPUC RPS Calculator, which also provides project specifications of new RPS projects. Table 8 has the calculation of renewable net short for the four scenarios.

Table 8: RPS Portfolio Net Shorts Calculation

	All Values in GWh for Year 2024	Formula	Trajectory	High Load	Expanded Preferred Resources	40% RPS in 2024
1	Statewide Retail Sales - Dec 2013 IEPR		300,516	317,781	300,516	300,516
2	Non RPS Deliveries (CDWR, WAPA, MWD)		9,272	9,272	9,272	9,272
3	Retail Sales for RPS	3=1-2	291,244	308,509	291,244	291,244
4	Additional Energy Efficiency		24,410	24,410	36,713	24,410
5	Additional Rooftop PV		0	0	5,360	0
6	Additional Combined Heat and Power		0	0	16,016	0
7	Adjusted Statewide Retail Sales for RPS	7=3-4-5-6	266,834	284,099	233,156	266,834
8	**Total Renewable Energy Needed For RPS**	8=7*33% or 7*40%	**88,055**	**93,753**	**93,262**	**106,734**
	Existing and Expected Renewable Generation					
9	Total In-State Renewable Generation		42,909	42,909	42,909	42,909
10	Total Out-of-State Renewable Generation		10,639	10,639	10,639	10,639
11	Procured DG (not handled in Calculator)		2,204	2,204	2,204	2,204
12	SB 1122 (250 MW of Biogas)		1,753	1,753	1,753	1,753
13	**Total Existing Renewable Generation for CA RPS**	13=9+10+11+12	**57,504**	**57,504**	**57,504**	**57,504**
14	**Total RE Net Short to meet 33% or 40% RPS in 2024**	14=8-13	**30,551**	**36,249**	**35,758**	**49,230**

Source: CPUC RPS Calculator

The "Total Renewable Energy Needed for RPS" in row 8 of Table 9 is exactly the renewable energy needed to meet the RPS goals of the scenarios. If renewable energy is curtailed, even for just 1 MWh, in the simulation, the RPS goals set for the scenarios will not be met.

Q. What is the renewable technology mix that you used for each scenario?

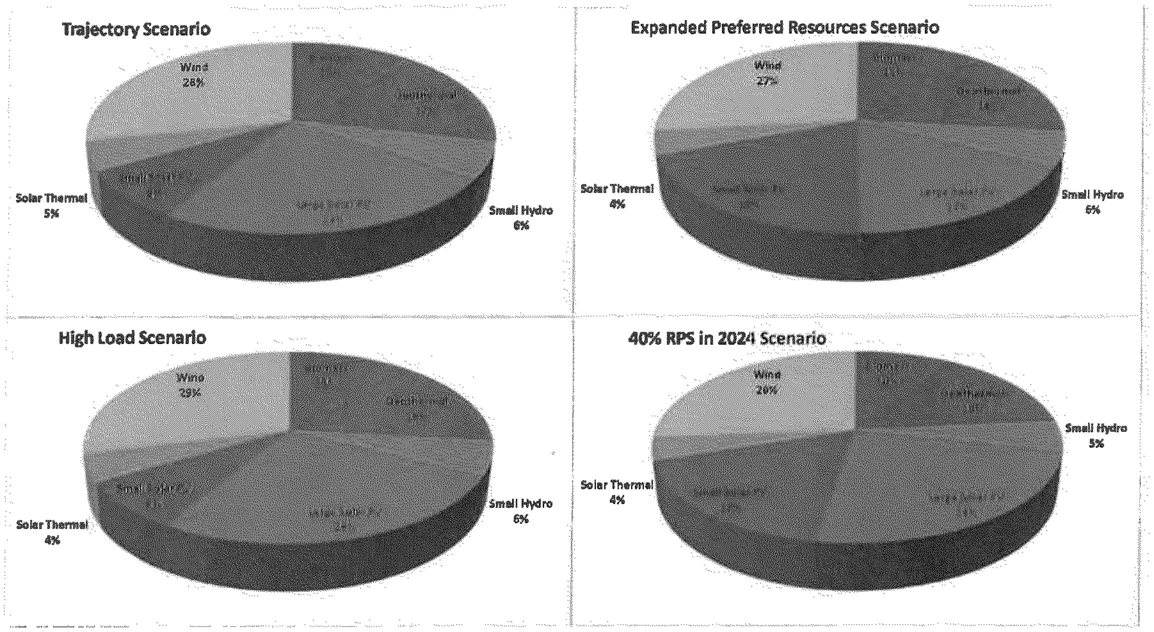
A. The technology mix of renewable resources for each scenario was from the CPUC RPS Calculator. Table 9 sets forth the information about the mix in NQC and energy.

Table 9: Renewable Portfolios by Scenario

	Biomass	Geothermal	Small Hydro	Large Solar PV	Small Solar PV	Solar Thermal	Wind	Total
Trajectory Scenario								
Capacity (MW)	1,623	2,999	3,017	9,087	3,564	1,802	11,146	33,239
Energy (GWh)	10,096	15,003	5,334	21,091	7,312	4,322	24,899	88,056
In-State Energy	9,534	13,645	5,294	17,787	7,312	4,322	15,701	73,595
Out-State Energy	562	1,358	40	3,304	0	0	9,198	14,461
High Load Scenario								
Capacity (MW)	1,626	2,999	3,017	10,615	3,705	1,802	11,904	35,668
Energy (GWh)	10,117	15,003	5,334	24,326	7,611	4,322	27,040	93,753
In-State Energy	9,555	13,645	5,294	21,022	7,611	4,322	17,842	79,292
Out-State Energy	562	1,358	40	3,304	0	0	9,198	14,461
Expanded Preferred Resources Scenario								
Capacity (MW)	1,623	2,999	3,017	6,849	8,942	1,660	11,111	36,201
Energy (GWh)	10,096	15,003	5,334	15,895	18,145	3,990	24,800	93,263
In-State Energy	9,534	13,645	5,294	12,591	18,145	3,990	15,601	78,801
Out-State Energy	562	1,358	40	3,304	0	0	9,198	14,461
40% RPS in 2024 Scenario								
Capacity (MW)	1,626	2,999	3,017	11,195	9,115	1,802	12,189	41,943
Energy (GWh)	10,117	15,003	5,334	25,597	18,518	4,322	27,844	106,734
In-State Energy	9,555	13,645	5,294	22,293	18,518	4,322	18,646	92,273
Out-State Energy	562	1,358	40	3,304	0	0	9,198	14,461

Figure 4 compares the renewable portfolios of the scenarios by resource type mix. Among the four scenarios, 40% RPS scenario has the highest share of solar energy (45%). The next is the Expanded Preferred Resources scenario (40%). The latter also has large amount of customer photo voltaic energy (5,360 GWh, see Table 8) that is not included in the pie chart. Solar generation has highest output in the middle of the day and drops off quickly in early evening. These two scenarios may have high renewable generation curtailments and some shortfall in upward capacity.

Figure 4: Comparison of Renewable Portfolios of the Scenarios



The solar resources also have different technologies. Each technology has its own generation patterns. For example, solar thermal with storage also has an hourly profile as its energy source from the collectors, as other solar resources in the model. However, its thermal storage can hold the collected energy until a later time. The resource becomes dispatchable and can provide ancillary services and load following. That is very different from solar photo voltaic and solar thermal without storage. Table 10 shows the mix of different solar technologies for the Trajectory scenario.

Table 10: Solar Resources Technology Mix – Trajectory Scenario

New Large Solar PV

	Capacity (MW)	Energy (GWh)
Crystalline Tracking	1,437	3,432
Thin-Film	5,974	13,672
Total	**7,411**	**17,104**

New Solar Thermal

	Capacity (MW)	Energy (GWh)
Solar Thermal with Storage	150	473
Solar Thermal without Stoı	1,200	2,804
Total	**1,350**	**3,277**

Q. What were the assumptions about modeling renewable generation?

A. As discussed above, we modeled all renewable resources with fixed generation profiles. We developed solar and wind profiles in Step 0 using base shapes with 2005 weather condition and energy forecasts from the CPUC RPS Calculator. Small hydro uses 2005 actual generation as base shape for profile development. Geothermal and bio gas have flat profiles.

We assumed that California RPS solar and wind generation were to be fully dispatchable (curtalable), and assigned a -$300/MWh cost to such resources. When there is over-generation and energy price drops to -$300/MWh, these resources may be curtailed. Table 11 identifies the curtailable solar and wind resources.

Table 11: List of Curtailable Solar and Wind Resources

Existing Solar_IID	Existing Wind_SCE	Small_SolarPV_PG&E_VLY
Existing Solar_LDWP	Existing Wind_SDGE	Small_SolarPV_SCE
Existing Solar_OOS	Existing Wind_SMUD	Small_SolarPV_SDGE
Existing Solar_PGE_BAY	Large_SolarPV_IID	Solar_Thermal_SCE
Existing Solar_PGE_VLY	Large_SolarPV_PG&E_VLY	Wind_AESO
Existing Solar_SCE	Large_SolarPV_SCE	Wind_CFE
Existing Solar_SDGE	Large_SolarPV_SDGE	Wind_LDWP
Existing Solar_SMUD	Large_SolarPV_SPP	Wind_SCE
Existing Wind_OOS	Large_SolarPV_SRP	Wind_SDGE
Existing Wind_PGE_BAY	Small_SolarPV_IID	
Existing Wind_PGE_VLY	Small_SolarPV_PG&E_BAY	

For RPS renewable resources located outside of California, 70% of their generation was modeled as dedicated import.

Q. How did you model the resource procurement in southern California that the Commission authorized in the prior LTPP, R.12-03-014?

A. The model includes a portion of the Track 1 authorized capacity. Specifically, we added three 100 MW GT (Pio Pico) and 10 MW capacity increase to the MMC Escondido Aggregate repower to SDG&E. The CAISO added one 900 MW CCGT and thee 100 MW GT to SCE. The CAISO also included a 50 MW storage in SCE in the 1,285 MW total energy storage target. The CAISO did not include Track 4 reauthorized capacity in the model. In total, the CAISO did not model 2,315 MW Track 1 and Track 4 authorized capacity. The assumption about modeling Track 1 and Track 4 authorized resources was based on the guidance from the CPUC. The capacity should be considered in evaluating the capacity shortfall and renewable generation curtailment under the various scenarios.

Q. What were the assumptions about demand response modeling?

A. Demand response programs are event-based and non-event-based. The CAISO included non-event-based demand response in the load forecast in the study. The CAISO modeled event-based demand response as supply resources.

The event-based demand response resources have triggering prices. When the energy price reaches the triggering prices, the demand response resources are triggered and their loads are dropped. As shown in Table 12, the modeled demand response resources have two different triggering prices, \$600/MWh and \$1,000/MWh respectively. The resources with \$1,000/MWh price represent the current reliability demand response programs. They are available only for certain period of each day. This type of demand response resources should rarely be triggered. The demand response resources with \$600/MWh price could be triggered relatively more frequently. However their monthly energy limits dictate the maximum number of hours the demand response resources can be triggered.

Table 12: Event-Based Demand Response Resources

Utility	Price ($/MWh)	Max Capacity (MW)	Availability	Monthly Energy Limit (GWh)
PG&E	600	424	All Hours	8.5
PG&E	1,000	70	H12-19	
PG&E	1,000	6	H13-20	
PG&E		274	All Hours	
PG&E Total		**773**		**8.5**
SCE	600	1,169	All Hours	23.4
SCE	1,000	9	H12-19	
SCE	1,000	10	H13-20	
SCE		173	All Hours	
SCE Total		**1,361**		**23.4**
SDG&E	600	22	All Hours	0.4
SDG&E	1,000	17	H12-19	
SDG&E	1,000	3	H13-20	
SDG&E Total		**42**		**0.4**
Total		**2,176**		**32.3**

Q. Please explain how the energy storage target resources were modeled.

A. The state's energy storage target totals 1,325 MW. The Lake Hodges pumped storage (2x20 MW) can meet the requirement. Therefore the model has 1,285 MW storage all modeled as battery storage.

The storage resources are grouped by interconnection, connected to transmission or distribution network, or behind the meter (customer side), and by storage capability measured by number of hours of discharging at full capacity. Table 13 provides the breakdown of the groups. All the storage resources have a round-trip efficiency of 83.33%. Of the total storage resources, 873 MW, 660 MW of which is transmission connected and 213 MW is distribution connected, can provide ancillary services and load following in both charging and discharging modes. The rest cannot provide ancillary services or load-following, but can charge and discharge energy in response to energy prices.

Table 13: Specifics of Energy Storage Target Resources

	PG&E			SCE			SDG&E			Total
(MW)	2 hours	4 hours	6 hours	2 hours	4 hours	6 hours	2 hours	4 hours	6 hours	
Transmission	124	124	62	124	124	62	32	8	0	660
Distribution	74	74	37	74	74	37	22	22	11	425
Customer	43	43	0	43	43	0	15	15	0	200
Total	241	241	99	241	241	99	69	45	11	1,285

Q. Can you summarize the calculated ramp rates and outage rates?

A. Yes. The ramp rates were calculated as capacity weighted-average based on the CAISO Master File data. We performed the calculation by technology and capacity size groups.

Table 14: Ramp Rates and Outage Rates of Some Unit Types

Unit Type	Capacity Group 1 Ramp Rate (MW/min)	Capacity Group 2 Ramp Rate (MW/min)	Capacity Group 3 Ramp Rate (MW/min)	Capacity Group 4 Ramp Rate (MW/min)	Planed Outage Rate (%)	Forced Outage Rate (%)
COMBINED CYCLE	CAP_0-200	CAP_200-400	CAP_400-600	CAP_600 ABOVE	6.76	5.23
	6.58	8.44	15.61	15.54		
DIESEL / OIL CT	CAP_50-100				2.85	2.79
	5.00					
GAS STEAM TURBINE	CAP_0-200	CAP_200-400	CAP_400-600	CAP_600 ABOVE	9.11	4.01
	2.79	7.62	4.80	26.66		
GAS TURBINE	CAP_0-50	CAP_50-100	CAP_100-150	CAP_150 ABOVE	4.53	5.82
	9.26	12.32	17.14	19.41		
NUCLEAR	CAP_600 ABOVE				8.16	3.39
	6.98					
PUMPED STORAGE	CAP_0-200	CAP_200-400	CAP_400-600	CAP_600 ABOVE	8.65	6.10
	34.35	46.61	80.80	56.26		

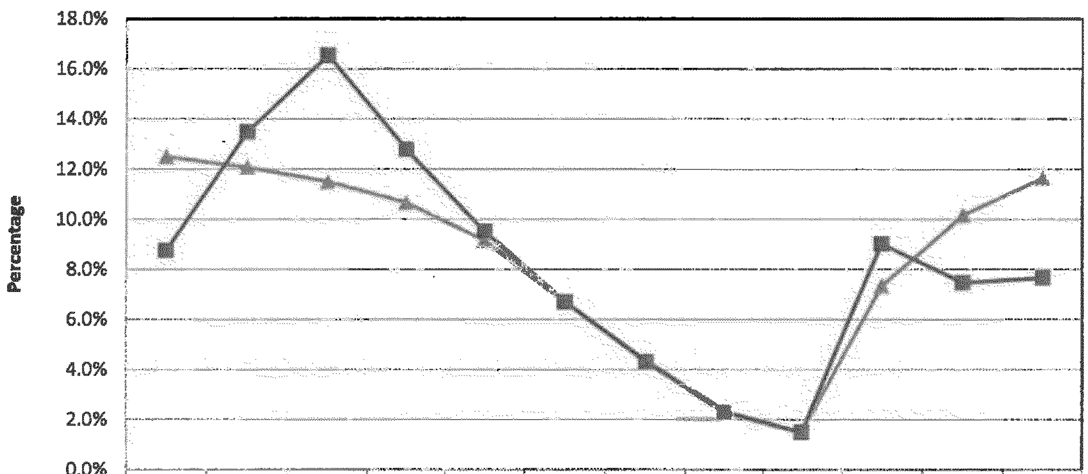
We calculated forced and maintenance outage rates as technology average based on the CAISO 2006-2010 actual outage data. In calculating forced outage rates, we subtracted Ambient and Normal Outage curtailed capacity from total available capacity as the denominators of the rates.

We applied the calculated ramp rates and outage rates to all California resources. The rates of some unit types are shown in Table 14. The ramp and outage rates for resources outside of California came from the TEPPC 2024 Common Case.

Q. How did you distribute maintenance outages to the months?

A. Maintenance outages of each resource can be managed by the maintenance outage rate allocation factors. The factors are used as weights to the resource's maintenance outage rate. Higher weight in a month will result in more maintenance outages in the month. For the whole year, the total percentage of time of maintenance outage equals the maintenance outage rate of the resource. Figure 5 shows the allocation factors used in the model. The red line reflects the factors calculated based on the CAISO 2010 actual outage data. They modified in the 2012 LTPP study to reflect the new maintenance patterns of California gas resources. We modeled other types of resources using the allocation factors on the red line.

Figure 5: Monthly Maintenance Outage Allocation Factors



	1	2	3	4	5	6	7	8	9	10	11	12
CA Gas Units	12.5%	12.1%	11.5%	10.7%	9.2%	6.7%	4.4%	2.4%	1.5%	7.3%	10.2%	11.7%
Others	8.7%	13.5%	16.6%	12.8%	9.5%	6.7%	4.3%	2.3%	1.5%	9.0%	7.5%	7.7%

Q. Please explain the sources of fuel prices used in the model.

A. The CEC provided natural gas price forecast in the 2013 IEPR for the whole WECC. The prices of all other fuels came from the TEPPC 2024 Common Case. Table 15 compares natural gas price in PG&E area used in 2012 and 2014 LTPP studies.

Table 15: Comparison of Natural Gas Prices (in 2014 $/MMBTU)

	2012 LTPP		2014 LTPP	
	PG&E BB	PG&E LT	PG&E BB	PG&E LT
Jan	4.56	4.73	4.38	4.99
Feb	4.30	4.47	4.43	5.03
Mar	4.21	4.38	4.27	4.86
Apr	4.34	4.50	4.26	4.85
May	4.48	4.64	4.24	4.82
Jun	4.54	4.71	4.29	4.88
Jul	4.62	4.78	4.13	4.70
Aug	4.27	4.44	4.11	4.68
Sep	4.23	4.39	4.01	4.56
Oct	4.39	4.56	4.24	4.82
Nov	4.75	4.91	4.46	5.06
Dec	4.80	4.97	4.63	5.24

Q. How did you model the CO2 emission price?

A: The CEC 2013 IEPR forecasted CO2 emission price is $23.27 per metric-ton (or $21.11 per short-ton in 2014 dollars.

As I described in Step 2 methodologies section above, the CAISO modeled CO2 cost (CO2 price times the fuel's emission rate) as a cost added to California fossil resources' generation variable cost. Fossil resources outside of California do not have the emission cost as generation variable cost adder. The CAISO modeled CO2 emission cost as a wheeling rate adder on all California import paths. The CAISO calculated the wheeling rate adder as:

0.435 metric-ton/MWh x 23.27 $/metric-ton = $10.12/MWh

For import from BPA, the wheeling rate adder was 20% of the adder value on other import paths. That is 20% x 10.12 = $2.02/MWh.[5]

Q. Please summarize the SCIT and California import limits for the studied scenarios.

A. The CAISO calculated the SCIT and California import limits for summer and non-summer seasons by time of day for each of the scenarios.

Table 16 provides the limits. It is generally true that with the increase of renewable resources in the SCIT area, inertia (from on-line resources with rotating mass) decreases, and so does the SCIT import limit.

Table 16: SCIT and California Import Limits

(MW)	Summer Peak	Summer Off-Peak	Non-Summer Peak	Non-Summer Off-Peak
Trajectory Scenario				
SCIT Limit	13,942	10,654	10,467	7,874
CA Import Limit	14,142	10,854	10,667	8,074
High Load Scenario				
SCIT Limit	13,393	10,187	9,899	7,508
CA Import Limit	13,593	10,387	10,099	7,708
Expanded Preferred Resources Scenario				
SCIT Limit	12,820	9,120	8,426	5,957
CA Import Limit	13,020	9,320	8,626	6,157
40% RPS in 2024 Scenario				
SCIT Limit	12,326	9,239	8,735	6,803
CA Import Limit	12,526	9,439	8,935	7,003

Q. How did you determine the ancillary services and load-following requirements?

[5] See http://www.arb.ca.gov/regact/2010/ghg2010/ghgisoratta.pdf about the BPA import CO2 charge.

A. The CAISO calculated regulation and load-following requirements in California in Step 1 using the PNNL statistical tool. Spinning and non-spinning each is 3% of native load (without being deducted by solar and wind generation). The CAISO has the ancillary services and load-following requirements for PG&E, SCE, and SDG&E together. The California municipals (IID, LADWP, SMUD, and TIDC) share ancillary services and load-following requirements.

For outside of California the requirements came from the TEPPC Common Case. Regulation-up and regulation-down are each 1% of load, and spinning and non-spinning are 3% of load each. Also, there were upward flexibility reserve requirements. Some zones outsides California share certain portion of ancillary services and flexibility.

VI. SIMULATION

Q. What production simulations did you conduct?

A. The CAISO ran production simulations for all five scenarios. The simulations were hourly chronological for the entire year of 2024.

The CAISO simulated (ran) each scenario twice. One is called "production cost run" and the other is "need run." The difference between the two runs are in the load following and regulation requirements.

The regulation and load following requirements calculated in Step 1 have "unique" values for each hour in the year. The production cost run uses the regulation and load following requirements values directly from Step 1. In need run, the CAISO pre-processed the regulation and load following requirement values before putting them into the production simulation model. For each requirement, the need run uses the monthly maximum value for each hour in the month. For example, in January, the load following-up value of hour 1 is the maximum load following-up value of hour 1 of the 31 days in January. The same value is assigned to hour 1 of all the 31 days. The pre-processing does the same for all other hours and months for each type of the requirements (load following-up, load following-down, regulation-up, and regulation-down).

The need run identifies capacity and flexibility. The concept was developed in 2010 LTPP study. The purpose of need run is to make sure that when the shortfalls are met with additional resources, there will be a small margin that can offset the possible errors in the requirements calculation or production simulation. The production cost run produces results of unit commitment and dispatch, costs, emission, etc. that reflect an actual system.

Q. How were the simulation results reported?

A. The simulations produced results that were reported in hourly, daily, weekly, monthly, or annual granularities, for each generation resource, each transmission paths, or each zone.

The CAISO has processed some results for most commonly asked questions and has posted these results on its ftp site. The results database (in Microsoft ACCESS format) that was created during the simulation and holds all results was also posted to the CAISO ftp site. Any party interested in the results can request download information from the CAISO.

VII. SIMULATION RESULTS

Q. Please summarize the simulation results.

A. The results of the five scenarios show upward shortfalls in all, but one scenario. Renewable generation curtailment occurred in all scenarios and some scenarios curtailment was significant. Because of the curtailment of renewable generation, the simulations did not identify any flexibility shortfall.

Q. What is the magnitude of the capacity shortfalls observed?

A. All of the scenarios except the Expanded Preferred Resources scenario resulted in capacity shortfalls. The highest shortfall was 5.353 MW from the high load scenario (see Table 17).

From trajectory scenario to trajectory without Diablo Canyon scenario, the maximum shortfall increased by 2,241 MW, which is the maximum capacity of the Diablo Canyon resource (2,240 MW).

Table 17: Summary of Capacity Shortfalls

Scenario	Upward/ Downward	Number of Hours	Maximum Shortfall (MW)	Types with Shortfall
Trajectory Scenario	Up	5	1,489	LF, Nspin
Trajectory without Diablo Canyon	Up	19	3,730	LF, Nspin, Spin
High Load Scenario	Up	34	5,353	LF, Nspin, Spin, Reg, energy
Expanded Preferred Resources Scenario		0	0	
40% RPS in 2024 Scenario	Up	9	2,242	LF, Nspin

Interestingly, the 40% RPS in 2024 scenario had a higher maximum capacity shortfall than the Trajectory scenario. The two scenarios have same load, but different renewable energy. Two factors contributed to the difference. First, with more renewable resources in the SCIT area, the 40% RPS in 2024 scenario's SCIT and California import limits were 1,616 MW lower than the Trajectory scenario in summer on-peak period. Thus, fewer imports were available to meet the load in California. Second, the 40% RPS in 2024 scenario has significantly higher solar energy than the Trajectory scenario (see RPS portfolio comparison above). Solar drops off quickly in early evening, as shown in Figure 6 (where BTMPV is behind-the-meter customer photo voltaic). That is why the highest capacity shortfall occurred two hours after the peak load hour (the California total native load peaks at hour-ending 16 on July 19, 2024).

Figure 7 shows all capacity shortfalls in the High Load scenario, breaking down by types. They all occurred in July and August. At July 19, 2024 hour-ending 18, there was a 5,353 MW total shortfall, including 219 MW unserved energy.

Figure 6: CAISO Energy Balance on July 19, 2024
– High Load Scenario

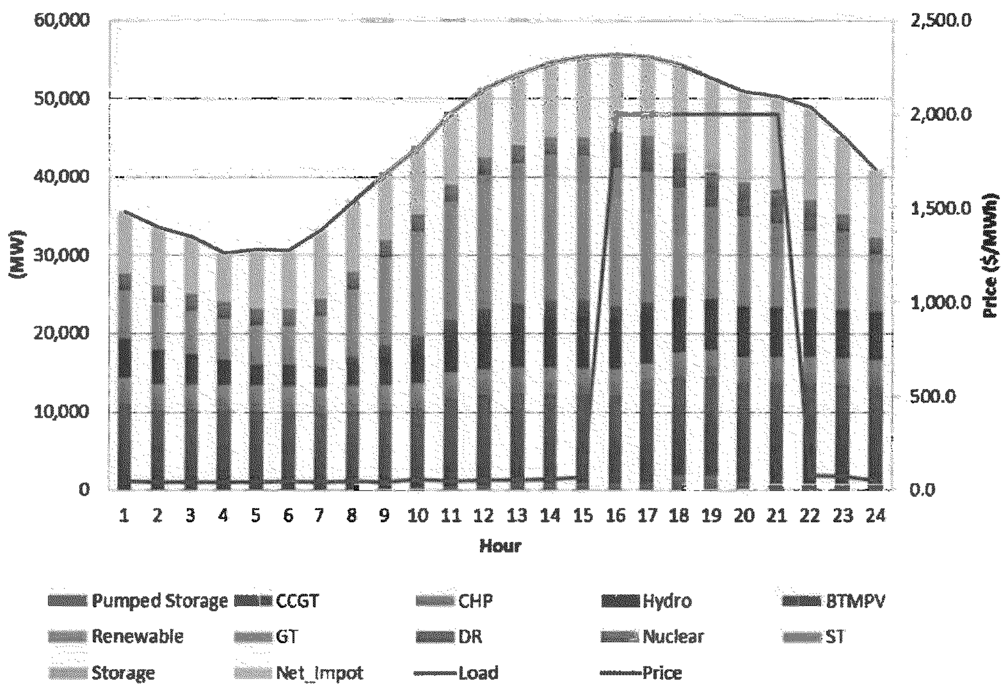
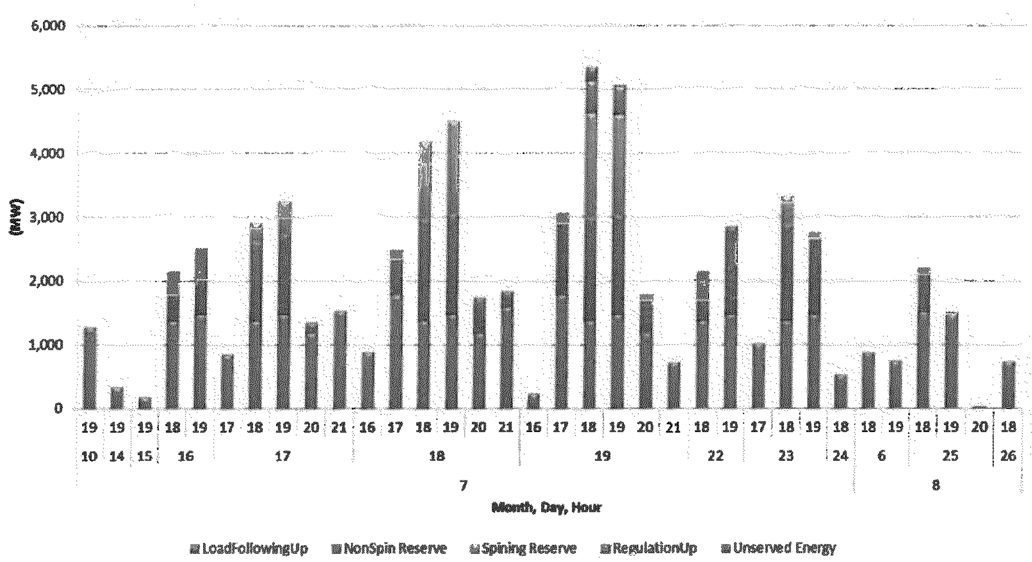


Figure 7: All Capacity Shortfalls – High Load Scenario



Q. Please explain the results of renewable generation curtailments.

A. All of the scenarios resulted in renewable generation curtailments. As shown in Table 18, the Trajectory without Diablo Canyon scenario has the least curtailment, as the case lost 2,240 MW of baseload resources. The Trajectory scenario had moderate curtailments, with annual 0.2% of the CAISO renewable energy being curtailed annually. However the highest single hour curtailment reached 5,927 MW, which is not insignificant. The curtailments in the Expanded Preferred Resources and 40% RPS in 2024 scenario were significant. The annual curtailments in those scenarios were 6.5% and 3.4%, respectively. The maximum hourly curtailments were above 14,000 MW and 13,000 MW respectively.

Table 18: Summary of the CAISO Renewable Curtailment

Month	1	2	3	4	5	6	7	8	9	10	11	12	Annual
Trajectory Scenario													
Number of Hours		2	26	47	16	5							96
Max Curtailment (MW)		243	5,927	5,410	2,984	2,025							5,927
Generation (GWh)	4,526	4,780	6,131	6,321	6,495	6,471	6,215	5,396	5,263	5,160	4,694	4,613	66,065
Curtailment (GWh)	0.0	0.5	48.4	76.7	21.7	6.2	0.0	0.0	0.0	0.0	0.0	0.0	153
Percent	0.0%	0.0%	0.8%	1.2%	0.3%	0.1%	0.0%	0.0%	0.0%	0.0%	0.0%	0.0%	0.2%
Trajectory without Diablo Canyon													
Number of Hours			9	14	1								24
Max Curtailment (MW)			2,960	3,383	99								3,383
Generation (GWh)	4,526	4,781	6,166	6,385	6,517	6,477	6,215	5,396	5,263	5,160	4,694	4,613	66,193
Curtailment (GWh)	0.0	0.0	13.3	12.8	0.1	0.0	0.0	0.0	0.0	0.0	0.0	0.0	26
Percent	0.0%	0.0%	0.2%	0.2%	0.0%	0.0%	0.0%	0.0%	0.0%	0.0%	0.0%	0.0%	0.0%
High Load Scenario													
Number of Hours			25	43	14	5							87
Max Curtailment (MW)			5,841	5,725	2,708	2,494							5,841
Generation (GWh)	4,840	5,142	6,626	6,825	7,011	6,967	6,691	5,778	5,641	5,524	5,021	4,933	70,999
Curtailment (GWh)	0.0	0.0	44.3	67.5	17.9	6.2	0.0	0.0	0.0	0.0	0.0	0.0	136
Percent	0.0%	0.0%	0.7%	1.0%	0.3%	0.1%	0.0%	0.0%	0.0%	0.0%	0.0%	0.0%	0.2%
Expanded Preferred Resources Scenario													
Number of Hours	35	49	185	231	205	161	34	25	73	63	68	36	1,165
Max Curtailment (MW)	5,238	9,323	13,543	14,599	12,289	11,522	8,434	3,611	7,819	7,666	4,526	4,738	14,599
Generation (GWh)	4,721	4,891	5,708	5,545	6,071	6,534	6,805	6,018	5,611	5,412	4,858	4,713	66,886
Curtailment (GWh)	54	126	846	1,396	961	574	107	40	186	165	126	57	4,637
Percent	1.1%	2.5%	12.9%	20.1%	13.7%	8.1%	1.6%	0.7%	3.2%	3.0%	2.5%	1.2%	6.5%
40% RPS in 2024 Scenario													
Number of Hours	15	29	141	202	165	114	20	5	36	33	42	20	822
Max Curtailment (MW)	3,384	7,484	12,927	13,402	10,035	9,363	5,006	557	4,770	5,849	2,805	2,862	13,402
Generation (GWh)	5,537	5,825	7,156	7,165	7,717	8,046	8,058	7,084	6,751	6,482	5,802	5,575	81,198
Curtailment (GWh)	15	59	583	1,013	594	291	47	2	70	88	48	17	2,825
Percent	0.3%	1.0%	7.5%	12.4%	7.1%	3.5%	0.6%	0.0%	1.0%	1.3%	0.8%	0.3%	3.4%

From the duration curves in Figure 8 you can tell the significance of the curtailments in Expanded Preferred Resources and 40% RPS in 2024 scenario. There were 200 to 300 hours with curtailment above 6,000 MW.

Figure 8: Duration Curves of the CAISO Renewable Curtailment

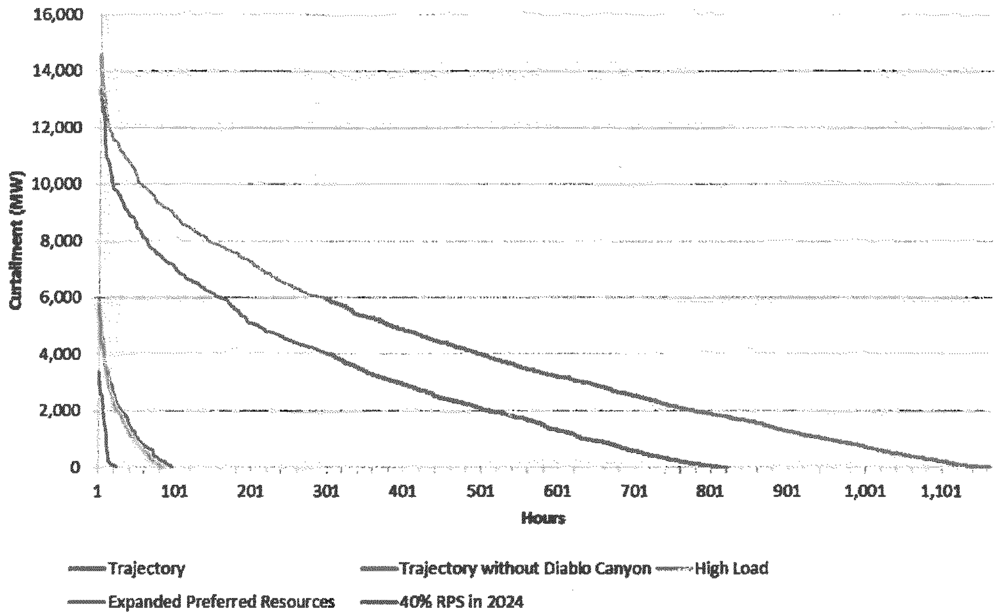


Figure 9: The CAISO Renewable Curtailment Distribution in April, 2024 - Expanded Preferred Resources Scenario

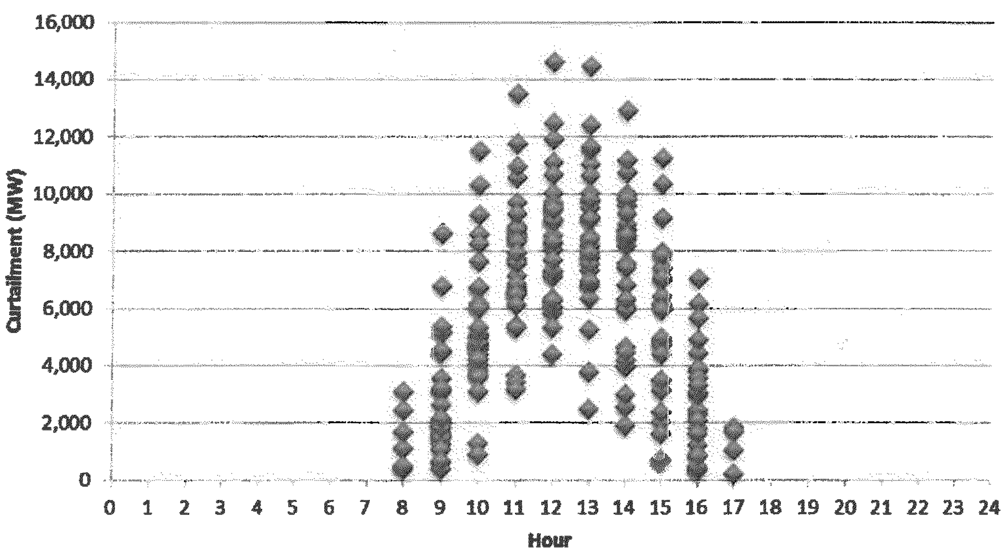
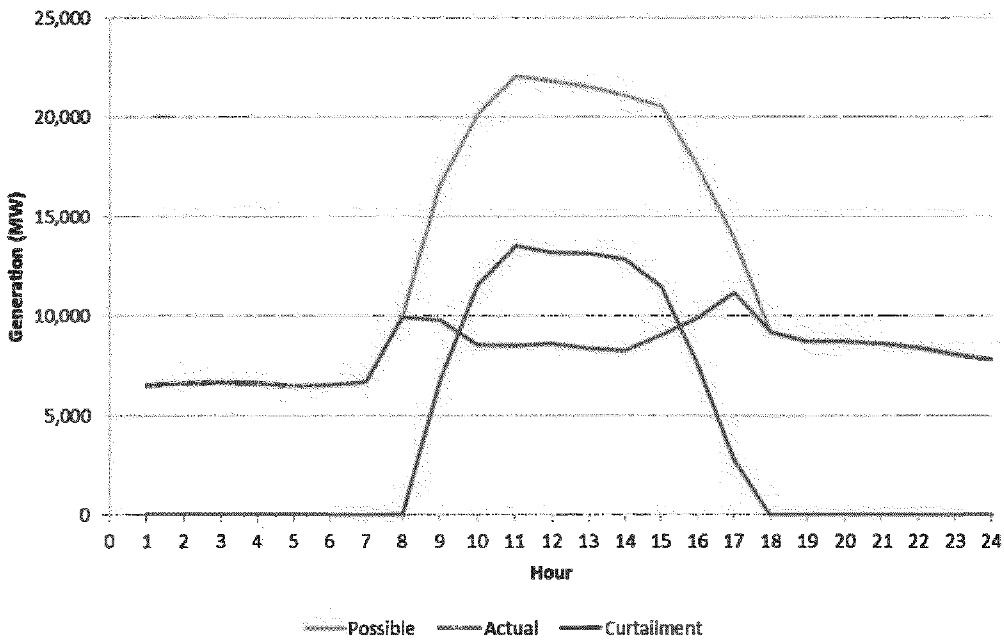


Figure 9 is the Expanded Preferred Resources scenario renewable curtailment distribution in April, 2024. It shows that all curtailments occurred between hour-ending 8 and 17. That is a clear sign that the curtailments were due to over-generation from solar resources.

Figure 10: The CAISO Renewable Curtailment (March 24, 2024) - Expanded Preferred Resources Scenario

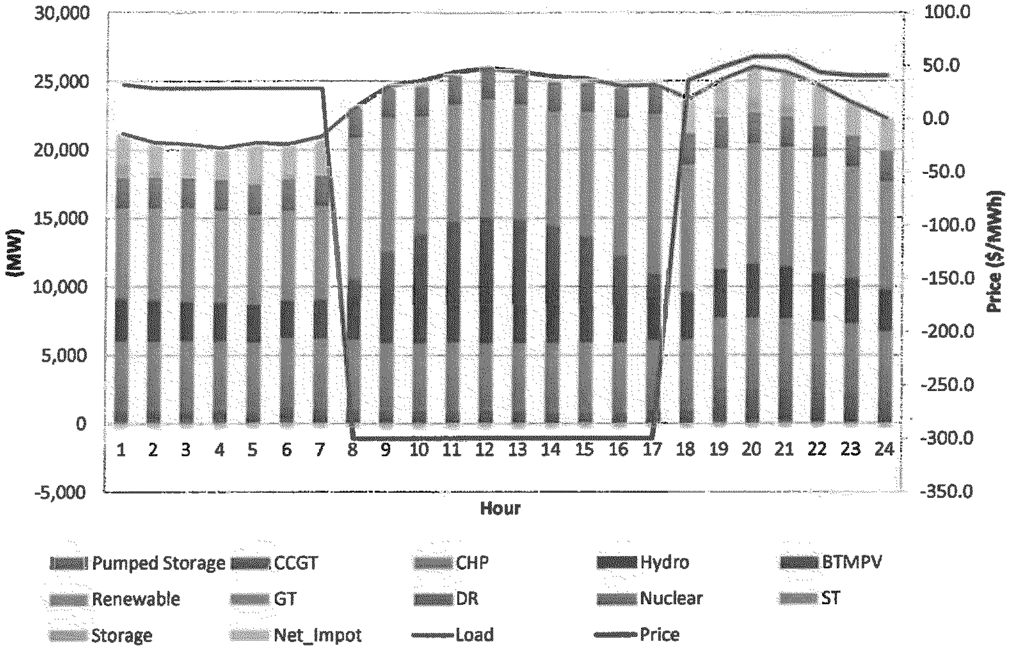


In Figure 10 is the renewable curtailment on March 24, 2024, which was one of the days with high curtailment. From hour-ending 10 to 15, more than 50% of the CAISO renewable generation was curtailed each hour. Renewable generation was almost flat.

When curtailment occurred, the CAISO net import was switched off. However there was no net export even when energy price dropped to -$300/MWh. That is demonstrated in Figure 11.

Figure 11: CAISO Energy Balance on March 24, 2024

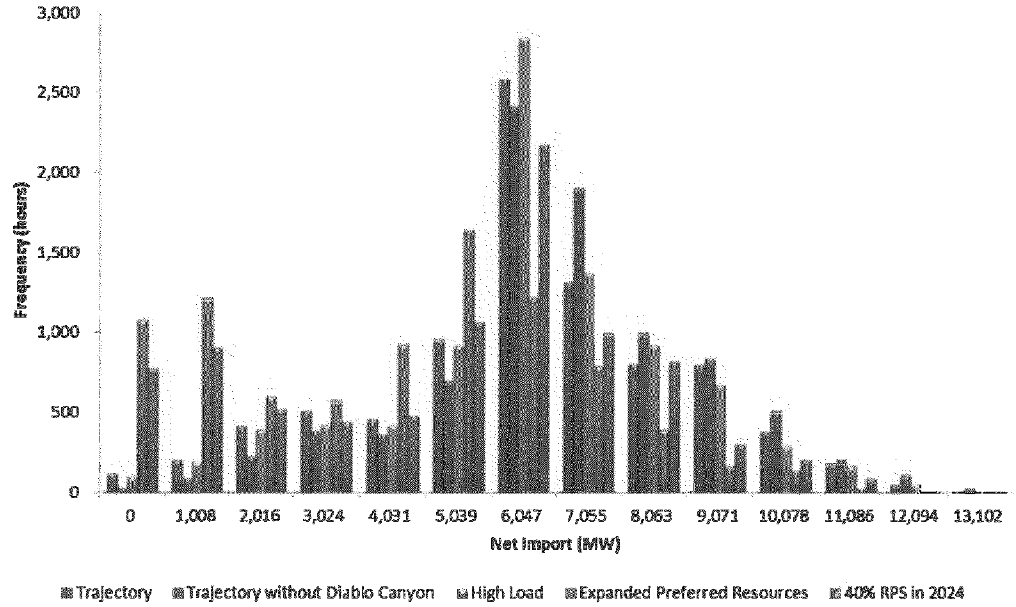
– Expanded Preferred Resources Scenario



Q. **What was the interplay between RPS portfolios and the CAISO net import?**

A. More renewable generation should reduce the CAISO's reliance on net imports. That is exactly what Figure 12 tells us. The trajectory scenario without Diablo Canyon case has the highest frequency high net imports. The Expanded Preferred Resources scenario has 40% RPS plus 5,360 GWh of customer photo voltaic. That scenario not only produced significantly reduced net import, but it also resulted in more than 1,000 hours of zero net import. These were due to over-generation and renewable generation curtailment.

Figure 12: Histogram of the CAISO Net Import



Q. How did RPS portfolio affect production cost and CO2 emission?

A. WECC total production costs and total CO2 emission are shown in Figure 13 and Figure 14. Both production costs and CO2 emissions were reduced with increase in RPS resources. This scenario did not consider the cost and emission impacts of re-dispatching resources to address over-generation issue without curtailing so much renewable generation. These cost and emission impacts should be taken into consideration in determining the appropriate policies regarding renewable generation curtailment.

Figure 13: WECC Total Production Cost[6]

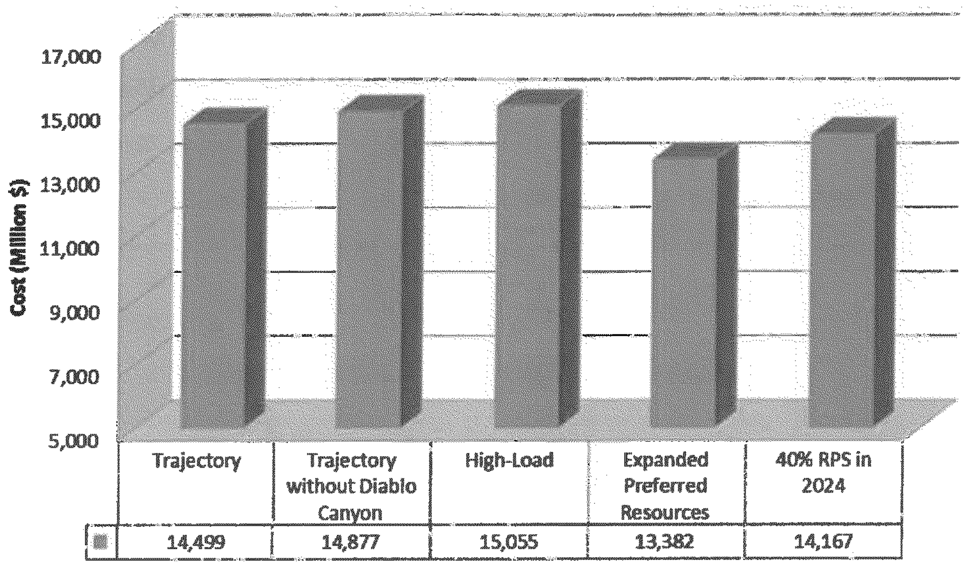
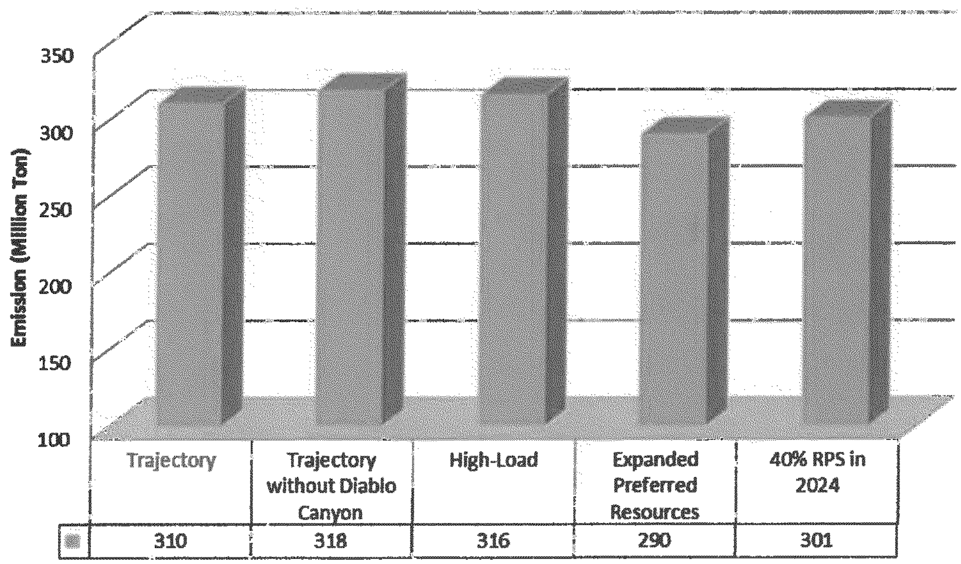


Figure 14: WECC Total CO2 Emission



[6] The production costs were adjusted by changing the cost of curtailable solar and wind resources from -\$300/MWh to \$0/MWh in post processing in order to be more intuitive and comparable.

Q. Please describe the pattern changes in California total production cost and CO2 emission with each scenario?

A. The California total production costs and total CO2 emissions have similar patterns of change with RPS portfolio (see Figure 15 and Figure 16). The percentages of changes in California are higher than the WECC. This is because the scenario assumptions assume only California RPS portfolios change within these scenarios. The rest of WECC did not have corresponding changes in renewable portfolios.

Figure 15: California Total Production Cost

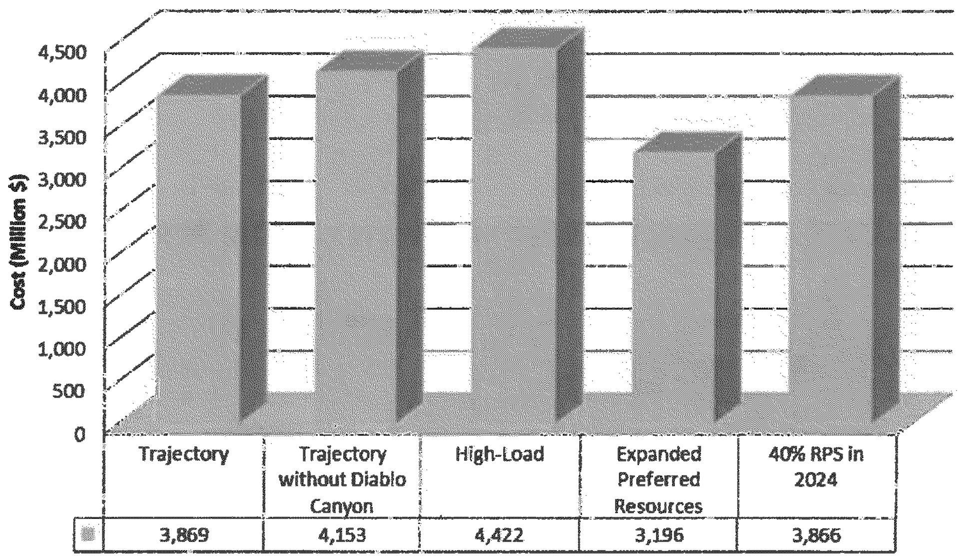
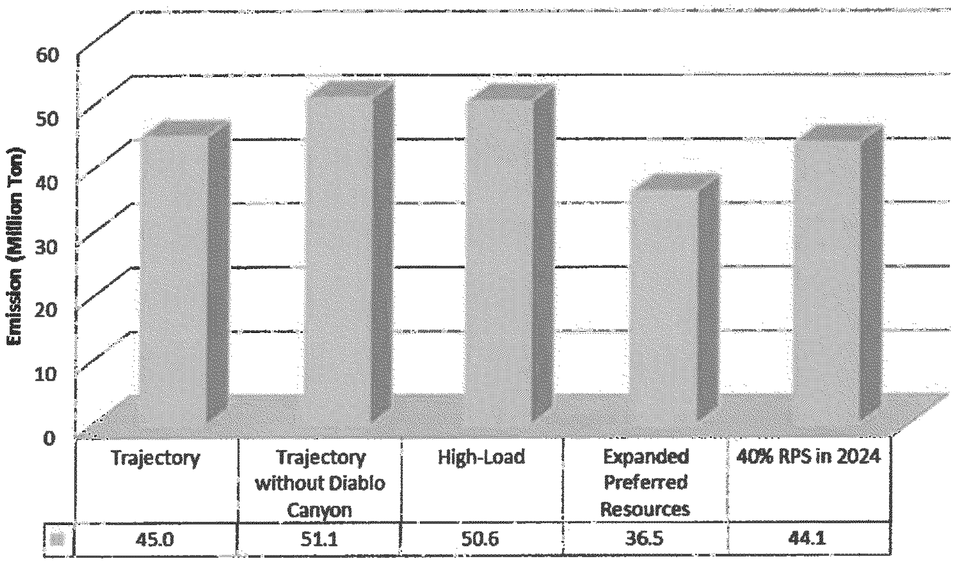


Figure 16: California Total CO2 Emission



VIII. NEXT STEPS

Q. What is the status of the CAISO's stochastic modeling?

A. The Commission has directed the CAISO to submit stochastic study results for the Trajectory scenario on November 13, 2014, and the CAISO will do so. I described the CAISO's stochastic modeling at the April 24, 2014 workshop in this proceeding. The CAISO does not intend to make any changes to the inputs and assumptions for the stochastic Trajectory study for the purposes of Phase 1a. Dr. Meeusen describes the CAISO's policy considerations and recommendations for additional studies in Phase 1b.

Q. Does this conclude your testimony?

A. Yes, it does.

IX. APPENDIX

Table 19: The CAISO 2024 Load Adjustment

High Load	Load Forecast*	AAEE**	Embedded Small PV**	Pumping Load**	Total Load
Load Forecast (MW)					
IID	1,299	0	0	0	1,299
LDWP	7,610	0	0	0	7,610
PG&E_BAY	10,378	-998	437	0	9,818
PG&E_VLY	15,971	-1,292	567	-614	14,631
SCE	28,383	-2,308	638	-421	26,292
SDGE	5,724	-567	218	0	5,375
SMUD	5,546	0	0	-143	5,404
TIDC	762	0	0	0	762
CAISO	**60,457**	**-5,165**	**1,859**	**-1,035**	**56,116**
CA	**75,674**	**-5,165**	**1,859**	**-1,178**	**71,190**
Load Forecast (GWh)					
IID	5,048	0	0	0	5,048
LDWP	34,417	0	0	0	34,417
PG&E_BAY	55,072	-4,193	1,484	0	52,362
PG&E_VLY	71,762	-5,708	2,020	-4,556	63,519
SCE	126,306	-10,239	2,313	-5,700	112,680
SDGE	25,959	-2,425	823	0	24,357
SMUD	21,251	0	0	-1,455	19,796
TIDC	3,157	0	0	0	3,157
CAISO	**279,099**	**-22,565**	**6,640**	**-10,256**	**252,918**
CA	**342,972**	**-22,565**	**6,640**	**-11,711**	**315,336**

Expanded Preferred Resources	Load Forecast*	AAEE**	Embedded Small PV**	Pumping Load**	Total Load
Load Forecast (MW)					
IID	1,241	0	0	0	1,241
LDWP	7,208	0	0	0	7,208
PG&E_BAY	9,614	-1,726	516	0	8,404
PG&E_VLY	15,569	-2,099	628	-614	13,484
SCE	26,882	-3,766	732	-421	23,427
SDGE	5,357	-898	251	0	4,710
SMUD	5,240	0	0	-143	5,097
TIDC	721	0	0	0	721
CAISO	**57,422**	**-8,490**	**2,127**	**-1,035**	**50,025**
CA	**71,833**	**-8,490**	**2,127**	**-1,178**	**64,292**
Load Forecast (GWh)					
IID	4,777	0	0	0	4,777
LDWP	32,618	0	0	0	32,618
PG&E_BAY	51,511	-6,667	1,696	0	46,540
PG&E_VLY	68,832	-9,302	2,366	-4,556	57,340
SCE	119,137	-16,339	2,696	-5,700	99,794
SDGE	24,271	-3,761	958	0	21,469
SMUD	20,117	0	0	-1,455	18,662
TIDC	2,978	0	0	0	2,978
CAISO	**263,751**	**-36,068**	**7,716**	**-10,256**	**225,143**
CA	**324,241**	**-36,068**	**7,716**	**-11,711**	**284,178**

40% RPS in 2024	Load Forecast*	AAEE**	Embedded Small PV**	Pumping Load**	Total Load
Load Forecast (MW)					
IID	1,241	0	0	0	1,241
LDWP	7,208	0	0	0	7,208
PG&E_BAY	9,614	-998	499	0	9,115
PG&E_VLY	15,569	-1,292	646	-614	14,308
SCE	26,882	-2,308	732	-421	24,885
SDGE	5,357	-567	251	0	5,041
SMUD	5,240	0	0	-143	5,097
TIDC	721	0	0	0	721
CAISO	**57,422**	**-5,165**	**2,127**	**-1,035**	**53,349**
CA	**71,833**	**-5,165**	**2,127**	**-1,178**	**67,617**
Load Forecast (GWh)					
IID	4,777	0	0	0	4,777
LDWP	32,618	0	0	0	32,618
PG&E_BAY	51,511	-4,134	1,696	0	49,073
PG&E_VLY	68,832	-5,767	2,366	-4,556	60,875
SCE	119,137	-10,239	2,696	-5,700	105,894
SDGE	24,271	-2,425	958	0	22,805
SMUD	20,117	0	0	-1,455	18,662
TIDC	2,978	0	0	0	2,978
CAISO	**263,751**	**-22,565**	**7,716**	**-10,256**	**238,646**
CA	**324,241**	**-22,565**	**7,716**	**-11,711**	**297,681**