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cc: Fitch, Julie A.; Charles, Melicia; Colvin, Michael; Kamins, Sara M.; Khosrowjah, Sepideh; Baker, Amy C.; Brown, Carol A.; Stevens, Brian

Subject: Analysis prepared by ORA for Track 2 of the LTPP proceeding (R.12-03-014)

Dear President Peevey and Commissioners:

Attached for your information is testimony prepared by ORA for Track 2 of the 2012 Long-Term Procurement Planning (LTPP) proceeding. At least one advisor indicated an interest in seeing this analysis even though this testimony is not part of the record.

Track 2 focused on determining whether California's system resources in 2022 are sufficient to support the State's goal of meeting 33% of demand with renewable portfolio standard (RPS) resources.

Shortly before the due date for service of the testimony, an Assigned Commissioner and Administrative Law Judge Ruling cancelled Track 2, indicating "[t]here has been some indication that system flexibility needs may be low or non-existent depending on the level of local capacity procurement authorized in Track 4."

The modeling ORA had already completed estimated whether additional resources will be needed in 2022 to balance supply and demand. The results are presented in the attached testimony. ORA similarly concluded that there is no immediate need to authorize procurement to meet system flexibility needs.

We would be happy to discuss this further with you or your advisors.

Thank you.

Joe Como
Office of Ratepayer Advocates

ORA's testimony in the 2012 Long Term Procurement Proceeding, Track 2:

Executive summary

(January 2014)

The California Public Utilities Commission (CPUC) oversees biennial Long-Term Procurement Plan (LTPP) proceedings to "ensure that California's major investor-owned utilities (IOUs) can maintain electric supply procurement responsibilities on behalf of their customers."[1] In these LTPP proceedings, resource needs are evaluated ten years into the future for the entire electric system in California and also for transmission-constrained local areas.

Parties to the LTPP proceeding opened in 2012, Rulemaking (R.)12-03-014, considered issues related to "system variability" in Track 2 of that proceeding. A series of workshops explored the methodologies associated with understanding and quantifying system variability. "System variability" is the interaction of changes in supply and demand, while "operational flexibility" refers to the resources needed to respond in real time to changes in supply and demand. California faces increased system variability because of its increasing reliance on intermittent renewable resources including wind and solar and it is therefore important to plan for adequate operational flexibility to meet system variability.

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[1] Scoping Memo and Ruling of Assigned Commissioner and Administrative Law Judge, issued May 17, 2012, in Rulemaking (R.) 12-03-014, p. 2. Available at http://docs.cpuc.ca.gov/SearchRes.aspx?DocFormat=ALL&DocID=60474

Parties were on the verge of filing testimony when a ruling was issued September 16, 2013, cancelling Track 2 of the proceeding. The following summary contains highlights of testimony prepared in late 2013 for the Office of Ratepayer Advocates (ORA)[2] by Robert M. Fagan and Patrick Luckow of Synapse Energy Economics. The complete testimony is attached.

Track 2 of the 2012 LTPP focused on determining whether California's electric system resources[3] in 2022 are sufficient to support the State's goal of obtaining 33% Renewable Portfolio Standard (RPS) resources to meet demand. Track 2 modeling estimated whether or not such additional resources will be needed in 2022 to balance supply and demand, taking into account the many system operational details projected for that year, including load growth, the ability of the transmission system to import resources from outside the system, the outage and response rates of generating units, and whether intermittent renewable resources provide more than 33% of California's energy in 2022.

ORA's Track 2 testimony reported the results of ten alternative Track 2 modeling scenarios ("ORA Scenarios") that Synapse executed on behalf of the ORA. Synapse used the Plexos modeling tool[4] to run the ORA Scenarios, starting with benchmark input files that the CAISO used for its Track 2 modeling.

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[2] The Division of Ratepayer Advocates was renamed the Office of Ratepayer Advocates effective September 26, 2013, pursuant to Senate Bill No. 96 (Budget Act of 2013: public resources), which was approved by the Governor of California on September 26, 2013.

[3] The system resources at issue are under the control of the California Independent System Operator Corporation (CAISO), which manages the flow of electricity for about 80 percent of California and a small part of Nevada, which encompasses all of the investor-owned utility territories and some municipal utility service areas. http://www.caiso.com/about/Pages/OurBusiness/UnderstandingtheISO/default.aspx

[4] The Plexos modeling tool is an hourly production cost simulation model used for resource planning.

Synapse's results show the projected patterns of electric power resource availability in 2022 during either i) all hours of the year, or ii) during just the hours in the projected peak summer month (July);[5] and how these patterns are affected by key scenario assumptions. The ORA Scenarios focus mainly on the impact of different levels of preferred resource (i.e., energy efficiency (EE), demand response (DR), solar photovoltaic (PV))[6] deployment by 2022. A few ORA Scenarios address import limitations and the potential addition of resources given the retirement of the San Onofre Nuclear Generating Station (SONGS) resource.[7]

Table 1 below shows a generally progressive reduction in identified "shortage" amounts from CAISO's base run shortage level of 2,621 MW (an amount that does not consider any effect of Track 1 authorizations not explicitly included in CAISO's base model[8]) in 2022. As incremental EE, DR, or PV is deployed (supplemental to the amount assumed in the CPUC scoping memo for the given scenario), or when demand response resources are assumed to be available for a different ("shifted") 6-hour window – namely, from 1 p.m. to 7 p.m. instead of from 11 a.m. to 5 p.m. – the modeled shortage level declines.

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[5] Some model runs were executed for all 12 months of 2022; and some ORA scenarios were executed just for July, the month in which demand is usually highest.

[6] Preferred resources also include combined heat and power (CHP) and storage. Primarily to minimize the permutations of modeling cases, in this examination we have not executed any modeling runs that varied the underlying case (base, Transmission Planning Process (TPP), high distributed generation (DG)/demand side management (DSM)) assumption for CHP deployment or storage (50 MW). To the extent that additional CHP or storage resources are deployed beyond that assumed for the case, our results will underestimate the system "headroom", or exaggerate any "shortage" finding.

[7] Authorization of resources to address the SONGS outage are part of Track 4 of the 2012 LTPP proceeding.

[8] CAISO has stated that the Moorpark sub-area of Big Creek/Ventura (215-290 MW) fossil resource, and preferred Track 1 procurements were excluded from its modeling.

In scenarios using the base load forecast and high levels of EE, DR, PV, and shifted DR availability, the "shortage" amount disappears (ORA Scenario 6), as it does in ORA Scenario 5 (high EE only). Excess available capacity during the tightest hour of the year is also observed in the model's results for CAISO's high DG/DSM scenario.

The analysis shows how different levels of resource deployment in 2022, across different net load forecasts, would lead to modeled surplus or shortage of resources at different points in time in that year. Generally, many modeled scenarios indicate shortages that occur for extremely brief intervals during one day of one summer month, with surplus capacity for the rest of the hours of the year. Modeled scenarios using more aggressive pursuit of preferred resources exhibit surplus capacity even during the tightest hour of the year.[9]

Modeling results that show occasional "shortages" do not imply that conventional gas-fired gas turbine or combined-cycle generation should be authorized for procurement at this time in an amount equal to the shortage capacity amount. The projected *patterns and duration* of modeled surplus or shortage should be evaluated when considering procurement decisions.

The modeling does not address the optimal timing for any resource procurement that is warranted or the best method of procurement. Based on current modeling results, ORA recommends limiting any procurement authorization to preferred resources.

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[9] It is notable that these scenarios, with higher levels of EE, DR and PV – and all other ORA Scenarios - contain no explicit assumptions for increased storage resources (e.g., up to 1,325 MW that may come to fruition by 2022 as authorized in the Decision 13-10-040) other than the 50 MW of storage authorized in Decision 13-02-015.

Table 1
Summary Results Plexos Hourly Modeling – July 2022 – ORA Scenarios

Scenario	Modeled Peak Hour Shortage (-) or Headroom (+), MW	Duration of modeled shortage (hours / days)	Comments
CPUC Scenarios Executed by CAISO			
Base	-2,621	4/1	
TPP (Oct 2013 Revision)[10]	-5,378	17/4	
High DG/DSM	+750	0/0	
ORA Scenarios - Base Load			
1- Shift DR Available	-1,272	3/1	DR 1-7 p.m. instead of 11 a.m. – 5 p.m.
2 -Shift DR Available and High DR	-1,171	3/1	High DR separate from Shift DR Available
3 -High PV	-2,444	2/1	
4- High PV and Shift DR Available	-1,095	2/1	
5- High EE	+828	0/0	
6- High EE, High PV, High DR, Shift DR	+1,912	0/0	
7- Shift DR Available and Relax SCE Import	-1,272	3/1	35% in-area gen – SCE
8- Shift DR Available and Relax CA Import	-1,084	3/1	Use High DG/DSM case import limit
9- 500MW Addition, Shift DR Available, High DR, Relax CA Import	-482	1/1	Add 500 MW SCE Track 4 proxy
ORA Scenarios - TPP Load			
10- Mid EE/DR and DR Available and Mid PV (Sept TPP inputs posting)	-2,701	9/3	

Notes:

1. Track 1 fossil resource at Big Creek/Ventura (215-290 MW) is not considered in these runs. To the extent it was used, all shortages decrease (or surpluses increase) by this amount.

2. CAISO scenarios exclude any preferred resource authorization from Track 1 except to the extent it is part of the preferred resource assumptions from the Track 2 scoping memo.

[End of Summary]

[10] Initial TPP results provided in the August 26th, 2013 LTPP workshop showed 5,359MW of shortage with a duration of 16 hours over 4 days. Afterwards, CAISO updated the model with new demand response assumptions and updated minimum and maximum capacities for some generating resources.

Docket:	:	R. 12-03-014
Exhibit Number	:	
Commissioner	:	
Admin. Law Judge	:	
ORA Witnesses	:	Robert M. Fagan Patrick Luckow

OFFICE OF RATEPAYER ADVOCATES
CALIFORNIA PUBLIC UTILITIES COMMISSION

TESTIMONY OF ROBERT M. FAGAN AND PATRICK LUCKOW, SYNAPSE ENERGY ECONOMICS, ON BEHALF OF THE OFFICE OF RATEPAYER ADVOCATES

Final - Post Track 2 Cancellation – October 23, 2013

Order Instituting Rulemaking to Integrate and Refine Procurement Policies and Consider Long-Term Procurement Plans
Track 2

(RM.12-03-014)

San Francisco, California
September, 2013

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INTRODUCTION AND SUMMARY OF TESTIMONY

Q. What is the purpose and scope of this testimony?

A. The primary purpose of this testimony is to report the results of ten alternative Track 2 modeling scenarios ("ORA Scenarios") that Synapse executed on behalf of the California Office of Ratepayer Advocates (ORA). Synapse used the Plexos modeling tool to run the ORA Scenarios, starting with benchmark input files posted by the California Independent System Operator Corporation (CAISO) after completion of its modeling work.

Synapse's results show the projected patterns of electric power resource availability in 2022 during either i) all hours of the year, or ii) during just the hours in the projected peak summer month (July)[1]; and how these patterns are affected by key scenario assumptions. The ORA Scenarios focus mainly on the impact of different levels of preferred resource (i.e., energy efficiency (EE), demand response (DR), solar photovoltaic (PV))[2] deployment by 2022. A few ORA Scenarios address import limitations and the potential addition of a Track 4 proxy resource in the ongoing phase of this proceeding that will consider additional local resource procurement given the retirement of the San Onofre Nuclear Generating Station (SONGS) resource.

We also discuss these results, examining the relevant issues that affect the integration of renewable resources and explaining what the results mean for possible procurement actions. We subsequently make procurement recommendations informed by the results of our analysis and consistent with the state's loading order policy.

Q. How does your analysis inform procurement options?

The driving factors affecting both the projection of future (2022) resource need and the procurement strategy to meet such need are complex. This testimony contains new analyses; uses information from existing CAISO work, from the California Public Utilities Commission (CPUC) Scenario tool (v6), and from the California Energy Commission (CEC) load forecast; recognizes Track 1 and Track 4 concerns; and ultimately shows how different levels of resource deployment in 2022, across different net load forecasts, would lead to modeled surplus or shortage of resources at different points in time in that year. Generally, many modeled scenarios indicate shortages that occur for extremely brief intervals during one day of one summer month, with surplus capacity for the rest of the hours of the year. Modeled

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[1] Some model runs were executed for all 12 months of 2022; and some ORA scenarios were executed just for the indicated "tight" month, July.

[2] Preferred resources also include combined heat and power (CHP) and storage. Primarily to minimize the permutations of modeling cases, in this examination we have not executed any modeling runs that varied the underlying case (base, Transmission Planning Process (TPP), High distributed generation (DG)/demand side management (DSM)) assumption for CHP deployment or storage (50 MW). To the extent that additional CHP or storage resources are deployed beyond that assumed for the case, our results will underestimate the system "headroom", or exaggerate any "shortage" finding.

scenarios using more aggressive pursuit of preferred resources – e.g.., the CPUC/CEC "high" levels of EE, DR and PV – exhibit surplus capacity even during the tightest hour of the year.[3]

In our opinion, modeling results that show occasional "shortages" do not imply that conventional gas-fired gas turbine (GT) or combined-cycle (CC) generation roughly equal to the shortage capacity amount should be authorized for procurement at this time. The projected *patterns and duration* of modeled surplus or shortage should be taken into account when considering procurement decisions in this Track.

The modeling itself says nothing about the optimal timing for any resource procurement that is warranted. Nor does the modeling indicate the best methods of procurement; California's hybrid structure (both market-based and cost-of-service based resource development) complicates procurement decisions. We discuss this issue and explain our position that preferred resource procurement authorization (only) is the best course at this time.

Q. How does your analysis account for Track 1 and Track 4 effects or potential effects on any Track 2 determination?

A. CAISO's analysis and the ORA Scenarios account for some resources authorized during Track 1[4]; those include 900 MW of CC and 100 MW of GT in southern CA (Southern California Edison (SCE) territory), and 50 MW of storage (located in the SCE territory in the model)[5]. Excluded from CAISO's runs are the Big Creek/Ventura (Moorpark sub-area) fossil authorization (215-290 MW) from D. 13-02-015 and the preferred resource authorization from that decision. Our ORA Scenarios include increasing levels of preferred resources that effectively account for, or exceed, the Track 1 preferred resource authorizations, but we also exclude the Big Creek/Ventura fossil authorization from our analysis.

The analysis also considers the effect of potential Track 4 (local reliability resource concerns in the absence of SONGS) procurement authorizations on overall system need by including three ORA Scenarios where import limits into CA or southern CA (SCE territory) are minimally increased (respectively, by 188 MW; or by adjusting the local generation requirement in SCE downward from 40% to 35%) to reflect the presence of increased generation in southern CA and/or the presence of transmission improvements and dynamic reactive support. In one of these ORA Scenarios an additional 500 MW resource is explicitly added in SCE's territory in the model;[6] and in the other two ORA Scenarios import limits are increased assuming

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[3] It is notable that these scenarios, with higher levels of EE, DR and PV – and all other ORA Scenarios - contain no explicit assumptions for increased storage resources (e.g., up to 1,325 MW that may come to fruition by 2022 as considered in the 9/3/2013 Proposed Decision in R. 10-12-007), other than the 50 MW of Track 1 resource authorized in Decision 13-02-015.

[4] See D.13-02-015, Ordering paragraphs 1 and 2 at pages 130-131.

[5] The Plexos model contains separate locations for SCE, Pacific Gas and Electric Company (PG&E) Bay, PG&E Valley, and San Diego Gas & Electric Company (SDG&E).

[6] We make no recommendations here about additional Track 4 needs. We run this Scenario to allow the Plexos modeling to explicitly account for the presence of another resource. We structure this resource as a 500 MW GT in the model but it serves only as a proxy resource available to meet peak period needs and

greater levels of distributed generation and/or transmission/reactive improvements, but no explicit additional Track 4 supply resource is added.

Q. Please summarize your modeling results.

A. Table 1 below summarizes the key results of ORA Scenario runs, and includes for comparison the CAISO's runs of Scoping memo scenarios.

doesn't imply that a GT is required to obtain the available capacity represented by the proxy unit. To the extent that Track 4 results in additional resources deployed by 2022 beyond the case assumptions we use, the results of our Track 2 modeling runs will underestimate the system headroom, or exaggerate any shortage finding.

Table 1. Summary Results Plexos Hourly Modeling – July 2022 – ORA Scenarios

Scenario	Modeled Peak Hour Shortage (-) or Headroom (+), MW	Duration of modeled shortage (hours / days)	Comments
CPUC Scenarios Executed by CAISO			
Base	-2,621	4/1	
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ORA Scenarios - Base Load			
1- Shift DR Avail	-1,272	3/1	DR 1-7 p.m. instead of 11 a.m. – 5 p.m.
2 -Shift DR Avail and High DR	-1,171	3/1	High DR separate from Shift DR Avail
3 -Hi PV	-2,444	2/1	
4- Hi PV and Shift DR Avail	-1,095	2/1	
5- High EE	+828	0/0	
6- Hi EE, Hi PV, Hi DR, Shift DR	+1,912	0/0	
7- Shift DR Avail and Relax SCE Import	-1,272	3/1	35% in-area gen – SCE
8- Shift DR Avail and Relax CA Import	-1,084	3/1	Use High DG/DSM case import limit
9- 500MW Addition, Shift DR Avail, High DR, Relax CA Import	-482	1/1	Add 500 MW SCE Track 4 proxy
ORA Scenarios - TPP Load			
10- Mid EE/DR and DR Avail and mid PV (Sept TPP inputs posting)	-2,701	9/3	

Notes:

1. Track 1 fossil resource at Big Creek/Ventura (215-290 MW) is not considered in these runs. To the extent it was used, all shortages decrease (or surpluses increase) by this amount.

2. CAISO scenarios exclude any preferred resource authorization from Track 1 except to the extent it is part of the preferred resource assumptions from the Track 2 scoping memo.

[7] Initial TPP results provided in the Aug 26th, 2013 LTPP workshop showed 5,359MW of shortage with a duration of 16 hours over 4 days. Afterwards, CAISO updated the model with new demand response assumptions and updated minimum and maximum capacities for some generating resources.

Q. Please explain the detailed results seen in Table 1.

A. Table 1 shows a generally progressive reduction in identified "shortage" amounts from CAISO's base run shortage level of 2,621 MW (this amount does not consider any effect of Track 1 authorizations not explicitly included in CAISO's base model[8]) in 2022. As incremental EE, DR, or PV is deployed (supplemental to the amount assumed in the CPUC scoping memo for the given scenario), or when demand response resources are assumed to be available for a different ("shifted") 6-hour window – namely, from 1 p.m. to 7 p.m. instead of from 11 a.m. to 5 p.m. – the modeled shortage level declines.

In scenarios using the base load forecast and high levels of EE, DR, PV, and shifted DR availability, the "shortage" amount disappears (ORA Scenario 6), as it does in ORA Scenario 5 (high EE only). "Headroom", or excess available capacity during the tightest hour of the year is also observed in the model's results for CAISO's high DG/DSM scenario.

Q. Does "shortage" imply a requirement for resource procurement during this LTPP cycle?

A. No. As seen in Table 1, and expanded upon in subsequent sections of this testimony, the shortage values are for very infrequent duration in the model. The "shortage" indication suggests that at this point in the planning cycle, existing and approved resources and projected retirements don't quite deliver as much capacity as the system may need for a few hours in 2022, but that suggestion is dependent on all the details inherent in the modeling system used.

The details include outage and response rates of units, transmission system import capability, limits on RPS resource deployment tied to 33% RPS (additional renewable resources that result in greater than 33% RPS energy by 2022 are possible), maximum DR potential, and inherent load growth and net load growth assumptions.

Q. What is your opinion on how such detailed inputs may change over time?

A. In our opinion, it is likely that changes to these fundamental input parameters over time will result in more, rather than less resource availability to meet "shortage" needs in 2022 than is seen in this LTPP cycle Track 2 modeling.

- Outage rates for supply resources in the model for the critical summer peak day could decrease as California implements "flexible ORA" and other ancillary service incentive structures within the CPUC RA regulatory regime and the CAISO markets. Currently, there are 2,241 MW of resources out of service in California in the base case at the critical peak hour of 6 p.m. on July 22nd.
- As Track 4 solutions are put into place (including reactive support and new transmission upgrades), and if/as increased coordination is seen among

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[8] CAISO has stated that they have excluded the Moorpark sub-area of BC/V fossil resourced, and preferred Track 1 procurements.

- WECC balancing areas[9], maximum simultaneous transmission import levels into California or the CAISO balancing area could increase beyond what is currently modeled in the Plexos environment.

- RPS requirements are not likely to dip below 33%, but could very well increase; and even in the absence of increase, there may be economically beneficial reasons for more RPS energy to come online than the current 33% commitments suggest. Increasing levels of renewable resources will increase available capacity during currently-modeled shortage periods, and no incremental flexibility concerns arise in the model runs, at least for those using "high" levels of PV. This is understandable; any capacity contribution of solar PV resources, or wind resources, at 6 p.m. (for example) frees up other resources to be available as capacity headroom on the system.[10]

- Demand response (DR) potential could likely increase beyond the "high DR" levels from the Scenario tool (v6)[11], especially for the infrequent duration of load reduction that may be needed.

- The 2013 IEPR already shows a lower peak load projection for 2022 in the mid case than the 2011 IEPR showed for its 2022 mid case peak load. To the extent that load growth trends continue to change in this manner over time, residual procurement needs, if any, will decrease with each successive LTPP planning cycle, all else equal.

Q. Please summarize your conclusions.

A. We find that deploying feasible, and reasonable, levels of preferred resources will ensure sufficient system flexibility in 2022 while integrating statutory levels of renewable resources. In our opinion, no authorizations are required for "conventional" fossil-fired generation because the duration and pattern of modeled "shortage" is minimal and sufficient time exists to develop incremental preferred resources that could be available to fill any gap. Those resources include, in particular, targeted levels of demand response beyond those considered in the "high DR" cases that need be available on a very infrequent basis.

Lastly, we note here that there exists the potential to consider the presence of existing OTC units scheduled for retirement in 2020 as an "insurance policy" against underperforming preferred resource procurements. All scheduled OTC retirements – without any date extensions – are reflected in our modeling.

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[9] WECC – Western Electricity Coordinating Council. Federal and regional initiatives will continue to improve coordination and transmission system utilization efficiencies across the western region.

[10] Our modeling results account for any unit commitment effects that may be present. Those effects could, in theory, lead to de-commitment of resources in the day-ahead time frame because of solar PV or wind resources meeting need in certain intervals. But our modeling of high PV scenarios does not increase the amount of shortage seen in those intervals – shortage is decreased.

[11] The current "high" level is 2,963 MW; mid-DR levels are 2,595 MW. Scenario Tool, v6.

TRACK 2 MODELING

Approach

Q. What is Track 2 modeling?

A. Track 2 of the 2012 LTPP is focused on determining whether or not system – as opposed to local – resources in the California region in 2022 are sufficient to support the State's goal of obtaining 33% RPS resources to meet demand. Track 2 modeling consists of analytically estimating whether or not such additional resources will be needed in 2022 to balance supply and demand, taking into account a myriad of system operational details projected for that year.

CAISO uses Plexos, a detailed hourly cost production model, for this analysis. Synapse uses Plexos in support of the ORA scenarios. The analytical structure of Plexos (in short, hourly dispatch and associated unit commitment) is intended to capture the capability of individual (and in the aggregate, system-wide) resources to provide energy and required operating reserve each hour of the year. Those resources include all supply and demand-side options available for California consisting of multiple types of generating and demand-response units using different fuels, and imports. It also accounts for additional reserve needed in every hour to balance out within-hour fluctuations of supply and demand. Those are referred to as "Step 1" inputs to the Plexos modeling process. The Plexos modeling method is intended to capture the hour-to-hour changes in resource output as the aggregate of all resources are used to meet fluctuating demand across each day of the year.

In order to properly account for the potential of imports to meet load, the Plexos model includes a detailed representation of the entire Western Electricity Coordinating Council (WECC), including CAISO, California municipal utilities, and loads and resources outside of the state.

Q. Please explain your approach in using the Plexos modeling tool to run "ORA Scenarios" using different combinations of input assumptions than those used by CAISO.

A. Synapse obtained a license from Energy Exemplar, the Plexos vendor, and used the same version of the software as used by CAISO.[12] Synapse executed monthly model runs for 9 different resource assumption scenarios, focusing mostly on July 2022, as this is the month exhibiting resource shortage in CAISO's execution of the base scenario. We ran annual (i.e., 12 monthly) model executions for the base, TPP and High DG/DSM cases and for one ORA Scenario with the DR availability "shifted" to the window 1p.m. to 7p.m., instead of the 11a.m to 5p.m. window utilized by CAISO in their runs.

Q. Please explain how you obtained and used data for the Plexos modeling.

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12 PLEXOS 6.208 R08

A. Synapse downloaded the CAISO-posted Plexos input files for the base case (July 15, 2013), TPP case (September 13, 2013) and High DG/DSM case (August 13, 2013). We then ran each of the base, TPP and High DG/DSM cases for all 12 months to ensure consistency with the CAISO results posted for those scenarios. We found our results to be consistent with CAISO's results. We then adjusted input parameters for each of those cases for a set of "ORA Scenarios" that used different combinations of input assumptions. Generally, our adjustments to those assumptions used a different level of CPUC-specified values: for example, the base scenario as specified in the CPUC scoping memo used a "mid" level of incremental PV resources. We used the "high" incremental PV level, as specified in the CPUC Scenario tool, to form the incremental PV input for some of the ORA scenarios. We did the same for the incremental EE assumption in some instances. For example, the TPP case starts out with a "low" incremental EE assumption, and we used a "mid" incremental EE assumption for the ORA scenario that starts with the TPP load forecast. We explain the ORA Scenario assumptions in full in the next section.

Preferred Resource and Other Assumptions – ORA Scenarios

Q. What are the ORA Scenarios?

A. ORA Scenarios are different combinations of input assumptions used in defining alternative Plexos scenarios. Generally, ORA Scenarios were run for one month in the Plexos modeling environment, though all 12 months were run for some cases. We show shortage/headroom values for this month (July), typically the most constrained month. For four scenarios, we ran all twelve months of 2022 in order to develop full-year duration curves to show modeled resource shortage or headroom over the entire year. These scenarios are the CAISO Base, TPP, and High DG/DSM cases, as well as the ORA Scenario adjusting the availability window of demand response resources.

Q. What combinations of preferred resource assumptions do you model in the ORA scenarios?

A. We model different levels of EE, DR and PV. We also model two relaxed transmission import limit scenarios, one where the California import limit was increased 188 MW to 14,053MW and one where SCE was required to have 35% local generation, compared to a default assumption of 40%. The CA import limit increase scenario was based upon the CA import limit used in CAISO's "high DG/DSM" case. The SCE local generation at 35% instead of 40% was a sensitivity to see how the system would respond if SCE was able to reduce its need for in-area generation through transmission and/or reactive support measures.[13] We note that the Plexos model structure as reflected in the base case does not preclude SCE generation from meeting less than 40% of in-area load, it just applies a penalty or violation amount (as part of the production cost for each hour of violation) if the

[13] We note that CAISO has stopped enforcing the SCE in-area generation minimum of 40% as of October 1, 2013. http://www.caiso.com/Documents/TechnicalBulletin-ImportLimitDefinitionandManagementinSupport-Under-FrequencyLoadShedding_UFLS.pdf.

model does not have sufficient in-area generation. Lastly, we model demand response resource availability "shifted" to the window 1p.m. to 7p.m., instead of the 11a.m to 5p.m. window utilized by CAISO in their runs. These variable changes, in different combinations, make up the set of 10 ORA Scenarios. Table 2 below lists the combinations modeled.

Table 2. ORA Scenarios – Assumption Parameters

	Inc Uncom EE	PV[14]	DR Capacity (Max)	DR Capacity (6 p.m.)	DR Avail Window	SCE Import Limit	CA Import Limit	Track 1 or 4 Fossil Addition
CPUC Scenarios as Run by CAISO								
Base	3,103MW	710MW	2,595MW	717MW	11-5	60/40	13,865	0
TPP	1,926MW	0MW	2,336MW	645MW	11-5	60/40	13,865	0
High DG/DSM	5,312MW	1,803MW	2,595MW	717MW	11-5	60/40	14,053	0
ORA Scenarios – Base Load								
1- Shift DR Avail	3,103MW	710MW	2,595MW	2,066MW	1-7	60/40	13,865	0
2- Shift DR Avail and High DR	3,103MW	710MW	2,962MW	2,167MW	1-7	60/40	13,865	0
3- Hi PV	3,103MW	1,803MW	2,595MW	717MW	11-5	60/40	13,865	0
4- Hi PV and Shift DR Avail	3,103MW	1,803MW	2,595MW	2,066MW	1-7	60/40	13,865	0
5- High EE	5,312MW	710MW	2,595MW	717MW	11-5	60/40	13,865	0
6- Hi EE, Hi PV, Hi DR, Shift DR	5,312MW	1,803MW	2,962MW	2,167MW	1-7	60/40	13,865	0
7- Shift DR Avail and Relax SCE Import	3,103MW	710MW	2,595MW	2,066MW	1-7	65/35	13,865	0
8- Shift DR Avail and Relax CA Import	3,103MW	710MW	2,595MW	2,066MW	1-7	60/40	14,053	0
9- 500MW Addition, Shift DR Avail, High DR, Relax CA Import	3,103MW	710MW	2,962MW	2,167MW	1-7	60/40	14,053	500
ORA Scenarios - TPP Load								
10- Mid EE/DR and DR Avail and Mid PV	3,103MW	710MW	2,595MW	2,066MW	1-7	60/40	13,865	0

Source: CPUC Scenario Tool v6, Synapse

[14] Incremental small PV.

Q. Please discuss the level of preferred resources assumed in the ORA Scenarios.

A. Most of the assumptions in Table 2 are taken directly from the CPUC Scenario Tool (v6) and the accompanying Summary Scenario Tool (v6) data. For ORA Scenarios 1 through 6, we retained the base load forecast assumption but modified, in different combinations, the EE, PV, DR, or DR availability parameters. For ORA Scenarios 7 and 8, we modified the DR availability window and changed the SCE internal generation minimum (7) and the CA import assumption (8). In ORA Scenario 9 we added 500 MW of capacity to the model in SCE's territory as a proxy for a Track 4 resource addition, along with shifting the DR availability, using the "high DR" level, and allowing increased CA import limits. In ORA Scenario 10, we retained the TPP gross load assumption but modified the EE, PV, DR, and DR availability values to reflect mid-case (EE, DR, PV) and shifted hours for DR availability.

Q. Please describe in detail the revised assumptions for DR time period availability.

A. Default inputs to the production cost model assumed DR was available from 11a.m. to 5p.m., based on existing standards. Review of the Base Case results made it clear that utilization of these resources could significantly reduce shortages. We pushed the window out 2 hours, to 1p.m. to 7p.m., to better match these potential shortage hours.

We shifted the 6 hour window, from 11:00 a.m. – 5:00 p.m. to 1:00 p.m. – 7:00 p.m. for SCE and SDGE's DR resources, to recognize that DR programs are not necessarily limited. The IOUs' tariffs reveal that very few DR programs are unavailable after 5:00 p.m. The Commission should direct the IOUs to measure and evaluate the potential "load drop" capability of existing and prospective DR programs in the 5:00 p.m. – 7:00 p.m. timeframe. At a minimum, air conditioning, pool pump, motor, and lighting load can all be shifted through 7 p.m. during the summer peak month. CAISO models a low amount of DR as available after 5:00 p.m., and it is reasonable to assume that DR programs could be structured to provide load drop capability after 5 p.m. It was important to model this change in DR availability not because we can currently document such availability, but to show how the rest of the dispatched resource system operates if such DR were available. The modeling value exists in showing how the overall system reacts to changes in parameters, and this DR parameter in particular has a dramatic effect on the modeled shortage during that key late afternoon / early evening summer period.

Q. Please describe in detail the revised assumptions for SCE area import capability.

A. The production cost model was set to require SCE to generate at least 40% of the power required to serve its load from SCE territory resources, above which a significant cost was imposed. We adjusted this downwards to 35% to allow the model to take further advantage of low cost import resources, if or as available, for this sensitivity. We make this assumption in order to demonstrate the effect on "shortage" levels, on the presumption that it may be feasible for SCE to make transmission/reactive support/operational improvements that would allow reliable operation with greater levels of imports into the SCE territory.[15]

Q. Please describe in detail the revised assumptions for CA import capability.

A. We used the higher CA import level present in the CAISO model inputs for the High DG/DSM case, which was 14,053 MW instead of the base MW level of 13,385 MW. We presume that this increased import level (relative to the base case) arises from the presence of greater amounts of generation in the SCE region in the High DG/DSM case. We also use this assumption in a sensitivity run where we add 500 MW of additional generation to serve as a proxy for Track 4 additional resources.

Q. How did you determine which permutations to model?

A. We wanted to illustrate the interactive effect of the preferred resource variables on modeled surpluses and shortages. For example, higher levels of PV might be considered something that would cause additional shortage because they introduce greater levels of intermittent resource output, but they also provide real MW during the shortage hour – 6 p.m – in the base scenario. Thus, with higher levels of PV, the dispatch for the day would change, since other resources would not be needed when those higher levels of PV are seen on the system.

Our selection of "the next level up" for each preferred resource (e.g., from "low" to "mid") is intended to show how modeled shortage levels would be lower if greater procurements of preferred resources were planned. The Energy Action Plan guides California's energy policies, and sets forth a loading order of preferred resources to meet energy needs, which places energy savings from or reduction in need due to EE, DR, and distributed generation such as CHP at the top of the loading order.[16] In this context, we support capturing all the cost-effective preferred resource potential before contemplating the procurement of conventional generation.

MODELING RESULTS AND PATTERNS OF SURPLUS/SHORTAGE

Load and Resource Output Patterns

Q. What does the CAISO region load and resource output look like, in the CAISO base case, the shifted DR availability case (ORA Scenario 1) and in a case with high levels of preferred resources (ORA Scenario 6), on the peak summer day of July 22, 2022?

A. Figures 1 through 3 below shows the pattern of resource output on the peak day for the CAISO region for each of those scenarios. Each of Figures 1 through 3 also shows the projected load pattern. During the interval between 3 p.m. and 10 p.m. on that summer day, gross load is steadily declining. As indicated, load declines roughly 7,000 MW between these hours.

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[15] As noted, CAISO has stopped enforcing this minimum generation restriction as of October 1, 2013.

[16] *Energy Action Plan II*, p. 2.

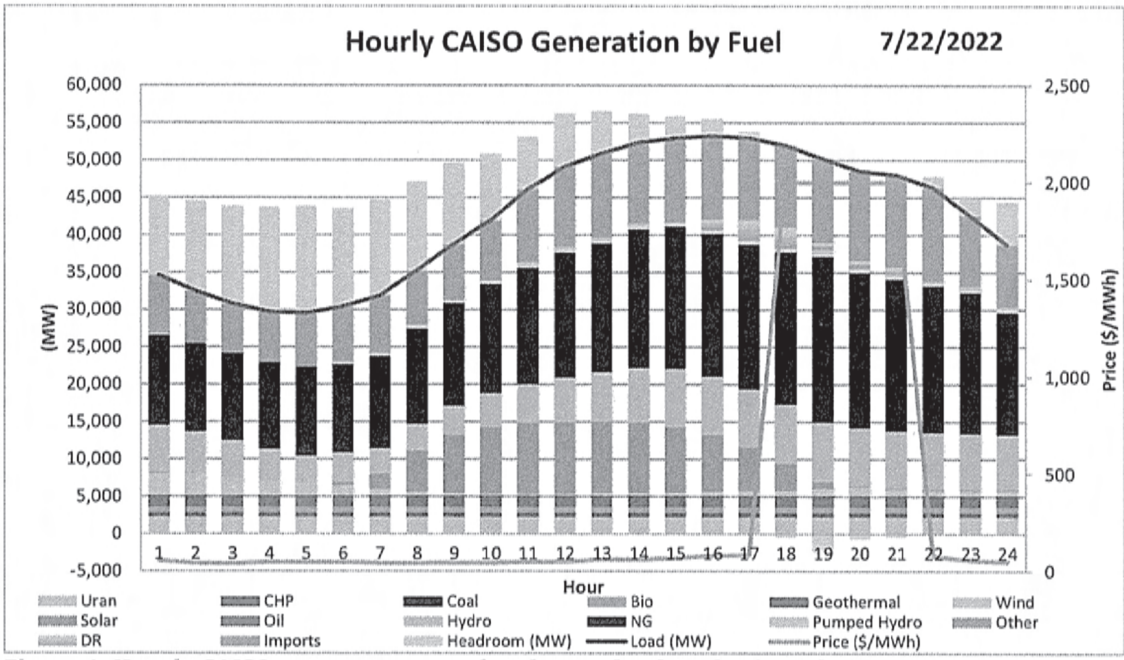


Figure 1: Hourly CAISO resource output, headroom, load, and price July 22 2022, CAISO Base Case

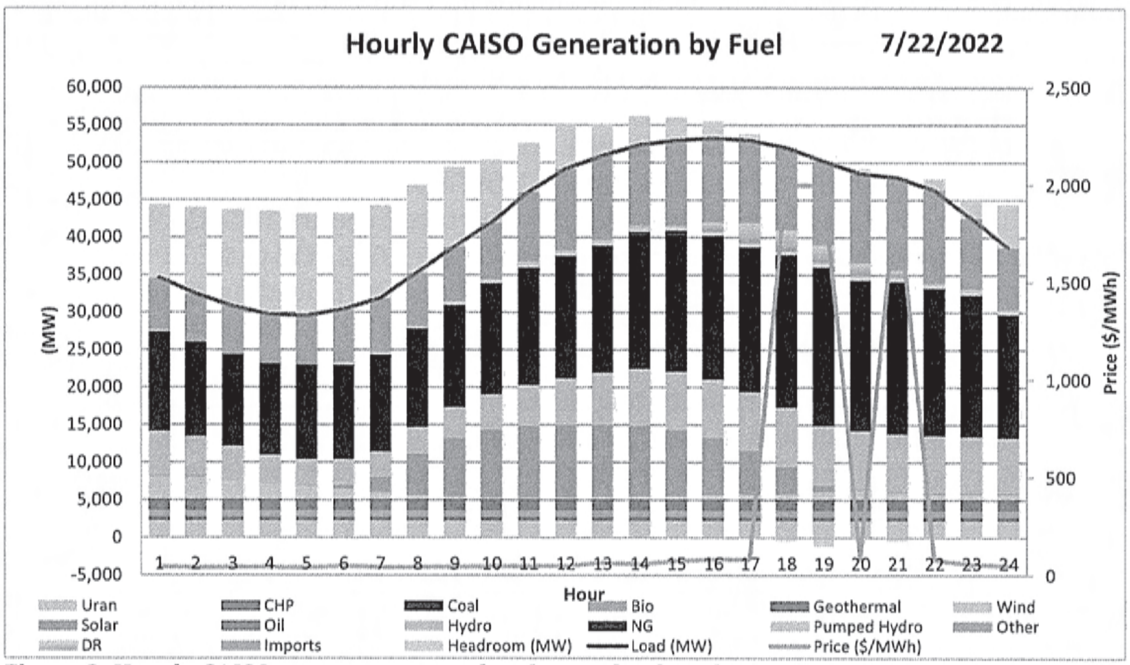


Figure 2: Hourly CAISO resource output, headroom, load, and price, July 22 2022 Base Case w/ Shifted DR Availability (ORA Scenario 1)

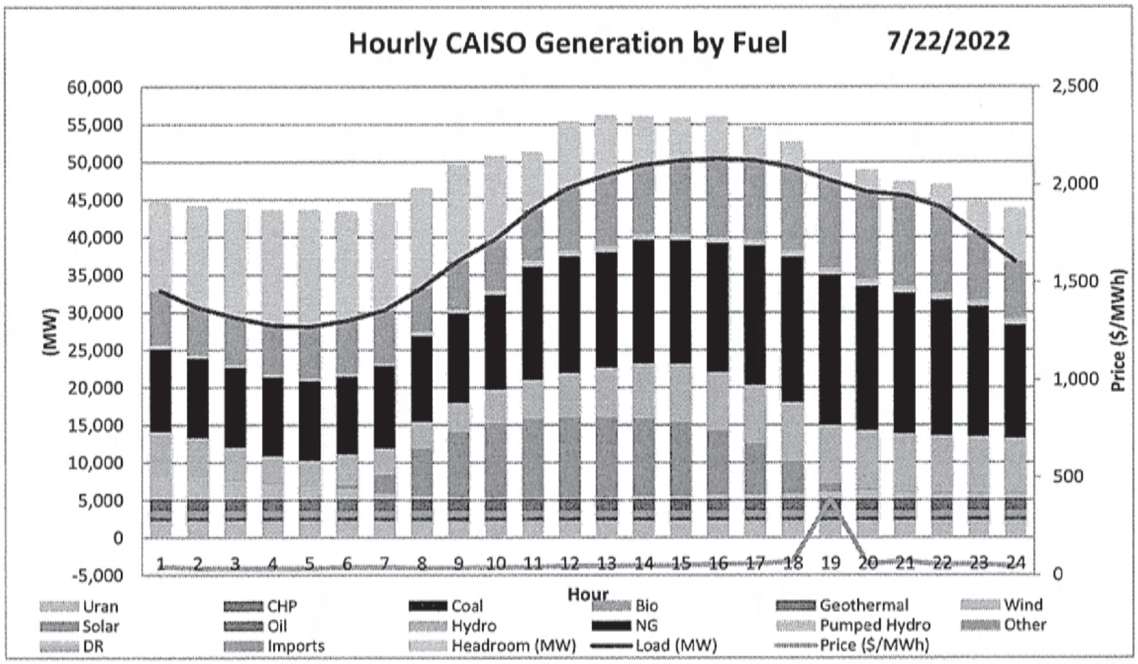


Figure 3: Hourly CAISO resource output, headroom, load, and price, July 22 2022 High Preferred Resources + Shifted DR availability case (ORA Scenario 6)

Q. Please explain the patterns shown in Figures 1 through 3.

A. Figure 1 illustrates the existence of a "shortage" in the CAISO base case at the four hours 18, 19, 20, and 21. There is no "Headroom" in those hours (top stacked bar), and the price spikes to $2,000/MWH. This price spike effectively serves as a proxy for shortage in those hours. In Figure 2, the availability of demand response is shifted out to 7PM, and while there is still a shortage in hours 18 and 19, it is significantly lowered from the base case values (from 2,612 MW to 1,272 MW shortage at 6 p.m.). The shortage also disappears in hour 20, leading to a total of 3 hours shortage for the day.[17] In Figure 3, when high levels of preferred resources are available, along with shifted DR availability, the "Headroom" shown by the top stacked bar exists in all hours, including the tightest late afternoon/early evening hours (1,912 MW headroom in the tightest hour 19). Figure 3 also shows a price spike in the tightest hour, hour 19, though this value is much lower than the $2,000 proxy price associated with a shortage.

ORA Scenario Modeling Results

Q. What are your summary results from Track 2 modeling using Plexos?

A. Table 3 lists the key results and scenario assumptions for all ORA Scenarios, and includes CAISO results for the three core scenarios (base, TPP, High DG/DSM).

[17] This result is an artifact of the specific hourly outages for the day, along with the combination of other resource output and load at those hours.

Table 3. Summary of Modeling Results for Highest Shortage Hour in July, 2022

	Scoping Memo – CAISO Runs			10 ORA Scenarios									
Scenario Name	**Base**	**TPP**	**High DG/DSM**	**Base modified 1**	**Base modified 2**	**Base modified 3**	**Base modified 4**	**Base modified 5**	**Base modified 6**	**Base modified 7**	**Base modified 8**	**Base modified 9**	**TPP modified 10**
Scenario elements / **Metric**	**Base**	**TPP**	**High DG/ DSM**	**Shift DR Avail**	**Shift DR Avail and High DR**	**Hi PV**	**Hi PV and Shift DR Avail**	**High EE**	**Hi EE, Hi PV, Hi DR, Shift DR Avail**	**Shift DR Avail and Relax SCE Import**	**Shift DR Avail and Relax CA Import**	**500MW Track 4, Shift DR Avail, High DR, Relax CA Import**	**Mid EE/DR and DR Avail and Mid PV**
Extreme Hour Shortage (-) or Headroom (+)	-2,621	-5,359	+750	-1,272	-1,171	-2,444	-1,095	+828	+1,912	-1,272	-1,084	-482	-2,701
Duration of shortage, hours / days	4/1	16/4	0/0	3/1	3/1	2/1	2/1	0/0	0/0	3/1	3/1	1/1	9/3
Peak Load	Base	TPP	Base	Base	Base	Base	Base	Base	Base	Base	Base	Base	TPP
Incremental EE	Mid	Low	High	Mid	Mid	Mid	Mid	High	High	Mid	Mid	Mid	Mid
DR Availability	11A - 5P	11A - 5P	11A - 5P	1P-7P	1P-7P	11A - 5P	1P-7P	11A -5P	1P-7P	1P-7P	1P-7P	1P-7P	1P-7P
Incremental Event-based DR	Mid	Zero	Mid	Mid	High	Mid	Mid	Mid	High	Mid	Mid	High	Mid
Incremental PV	Mid	Zero	High	Mid	Mid	High	High	Mid	High	Mid	Mid	Mid	Mid
SCE Import Limit	No change									35% in-area gen	No change		
Duration of Modeling Run	12 m	12 m	12 m	12 m	July	July	July	July	July	July	July	July	July

Q. Please explain the results in Table 3.

A. In general, Table 3 illustrates that the projected shortage or surplus level during the most extreme period in 2022 varies depending on the assumptions used for acquisition of preferred resources (e.g., EE, DR, PV) between now and 2022, and the availability timing for demand response resources. The results show that with reasonable pursuit of procurement of mid-to-high levels of preferred resources, the shortage periods are no more than four hours over no more than one day during the summer peak month (CAISO base case). For cases with procurement of additional preferred resources, the modeled shortage magnitude and duration is reduced, and in some cases eliminated entirely.

Q. What do the results show for the ORA Scenarios (which all exclude SONGS)?

A. The results first show that under "base" scenario assumptions excluding SONGS, with reasonable modifications[18] to the availability of demand-response resources during critical hours on peak days, the Plexos modeling reveals a single summer peak day in which a maximum hourly shortage of 1,272 MW is seen – reduced from a shortage of 2,621 MW seen in CAISO's base run that limited DR resource utilization to through 5 p.m. only; the total duration of shortage on this day is 3 hours. This is ORA Scenario 1. Under combinations of increased use of preferred resources using base case (no SONGS) inputs for all other variables, the modeling reveals reduced shortage amounts, for reduced duration. For ORA Scenarios with certain combinations of preferred resource procurement, the "shortage" values are eliminated.

ORA Scenario 8 shows the reduced shortage effect of a relaxed California Import limit (188MW CA import limit increase from base case) coupled with shifting the DR availability window. The addition of 500MW of local Track 4 resources (Scenario 9), in combination with high DR and shifted DR availability and an assumed increase in the California import limit reduces the shortage to 483MW.

Q. What do the results show for the "TPP" scenario excluding SONGS?

A. We ran one scenario using CAISO's "Replicating TPP" scenario assumption for load, but modified for preferred resource deployment. When modifying some of the preferred resource inputs and retaining the higher load forecast seen in the TPP scenario, the modeled shortage drops to 2,701 MW.

Q. What do the results show for the "High DG/DSM" scenario excluding SONGS?

A. Based on the "High DG/DSM" case run with no other changes, the shortage is fully mitigated, with significant headroom even during the tightest times of the year.

Patterns of Surplus/Shortage

Q. What do the modeling results reveal concerning the patterns of surplus or shortage over the course of all hours of 2022?

A. The data show that the tightest times remain during the summer period, though the prevalence of solar resources shift the tightest time frames to those of late afternoon/early

[18] No defined limit exists on the ability of DR resources to be available after 5 PM.

evening, rather than mid-afternoon as has been the historical critical period. Figure 4 below shows the annual pattern of hourly surplus/shortage for the base case. Figure 5 shows this annual pattern as an "availability duration curve", which sorts the data according to magnitude of shortage or surplus.

The annual duration curve and the sequential headroom/shortage data (in these graphs, for the CAISO base case) both illustrate that system needs spike for just a couple of modeled hours over the course of the entire year. This illustrates that sufficient headroom exists across the California system even with the presence of these three critical considerations: i) 33% RPS ii) once-through cooling (OTC) plant retirement levels, and iii) SONGS out of service. The fundamental patterns of supply and demand demonstrate the relative robustness of resource adequacy for the whole system.

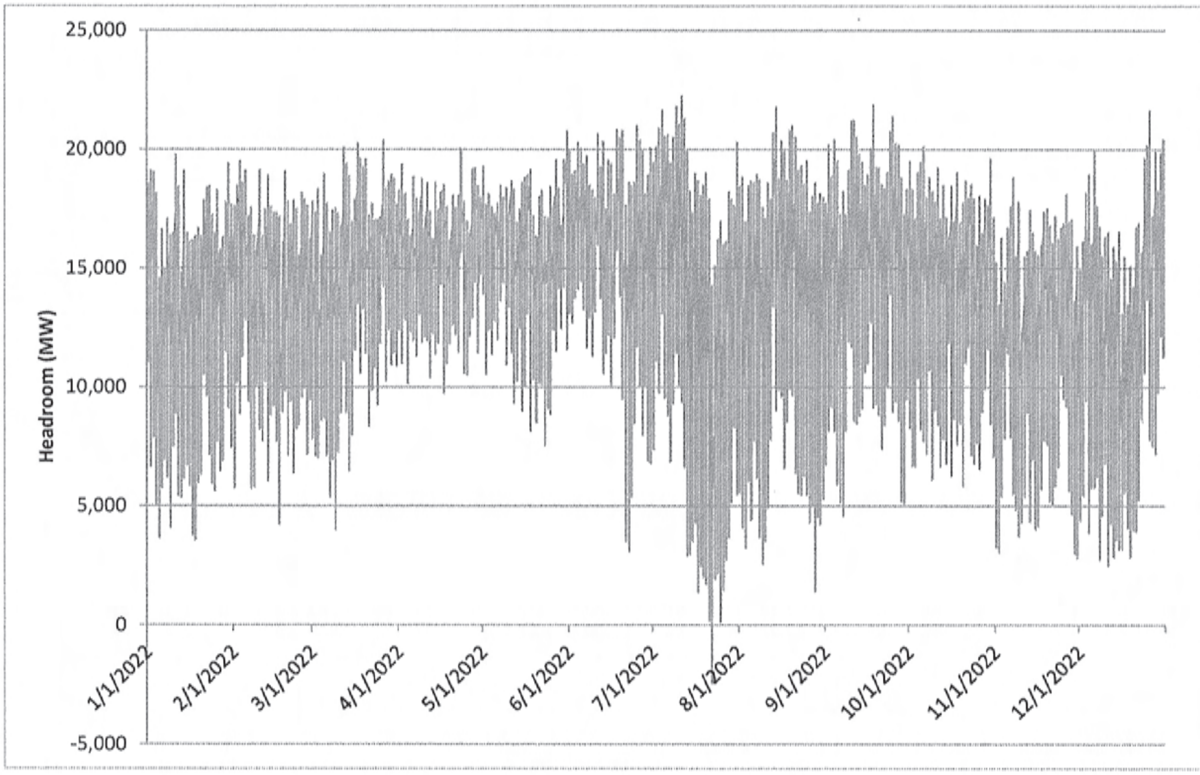
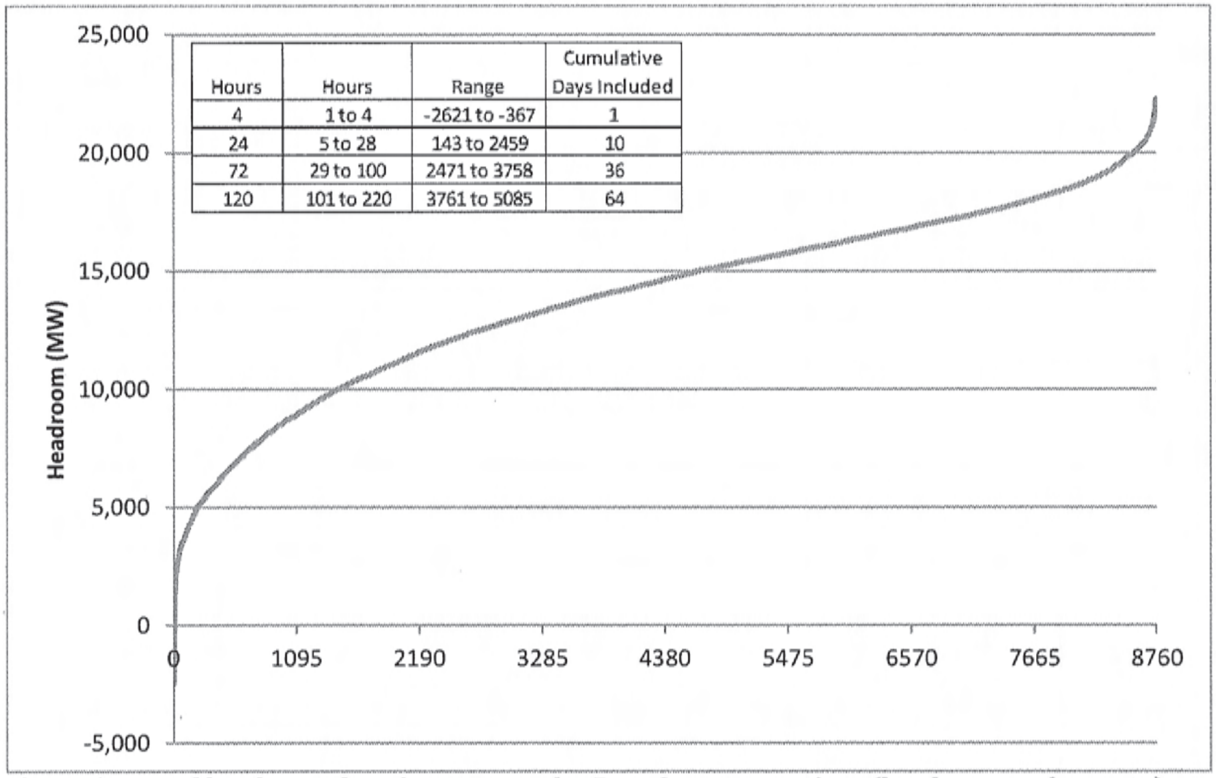


Figure 4: Annual headroom under the Base case assumptions, sequential hours of the year



Hours	Hours	Range	Cumulative Days Included
4	1 to 4	-2621 to -367	1
24	5 to 28	143 to 2459	10
72	29 to 100	2471 to 3758	36
120	101 to 220	3761 to 5085	64

Figure 5: Annual headroom duration curve under Base Case assumptions (headroom +, shortage -)

Notes:

1. Positive values are surplus ("headroom"); negative values indicate shortage.
2. 8760 hours in the year.
3. Inset table "hours" first column is the number of hours with shortage or surplus; the second column "hours" indicates where those hours fall in the sorted duration curve. The third column "range" is the shortage (-) or surplus (+) range for those hours over the number of "cumulative" days as listed.

Q. The annual duration curve was for the CAISO base case. Do you have figures for the ORA Scenarios?

A. Yes. We developed a set of graphs for July showing headroom[19] and shortage duration for the ORA Scenarios.

Q. What do the shortage/headroom patterns look like in the ORA Scenarios?

A. Figures 6 and 7 show these patterns for the peak month of July. Common trends emerge among the ORA Scenarios. These curves present the headroom in each hour, sorted from lowest to highest value. All scenarios exhibit the well-understood phenomenon that during the vast majority of hours there will be a substantial amount of headroom. There are only a few hours for which a potential shortage may exist. All scenarios with adjusted timing of demand response resources show substantially less shortage (upwards of 1,000MW of reduced shortage) in the top 24 hours than is otherwise seen if the timing is left as is in the CAISO base case. The scenarios with high levels of

[19] Headroom is defined as Available Capacity + Imports – Load – Reserve Provision.

energy efficiency demonstrate an additional 1,000MW of headroom in all of the top 24 hours.

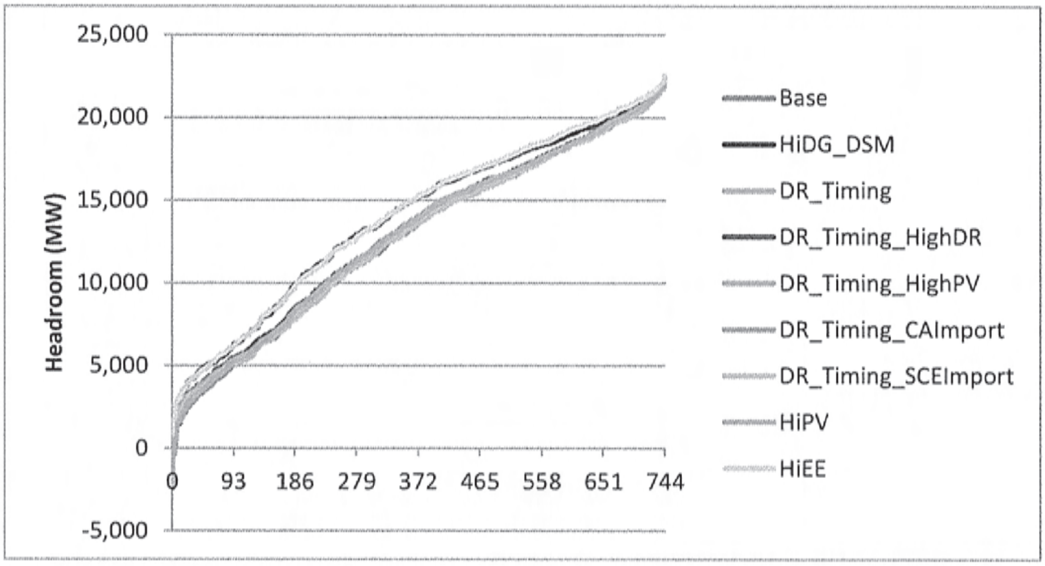


Figure 6: July 2022 Headroom Duration Curve (all hours)

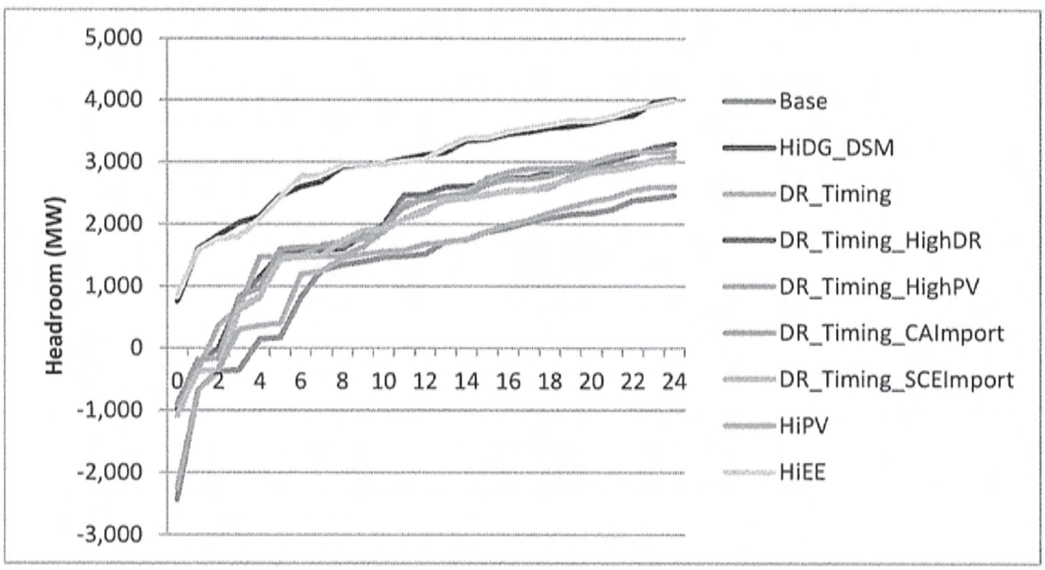


Figure 7: July 2022 Headroom Duration Curve (top 24 hours)

Patterns of Preferred Resource Output

Q. How do the hourly PV patterns align with the periods of shortage?

A. Solar PV facilities are distributed throughout the state and derive some benefits in terms of consistent hourly output as a result of this geographic diversity. The aggregate trend for both the peak day (Figure 8) and the average for the month of July (Figure 9) both show total solar output peaking near noon. At the identified hours of shortage in the base case (5 p.m. and 6 p.m., hours 18 and 19 below), total solar output is declining rapidly, but there remains significant output at 6 p.m. on the peak day, representing 642MW, and 818MW with high incremental small PV assumptions.

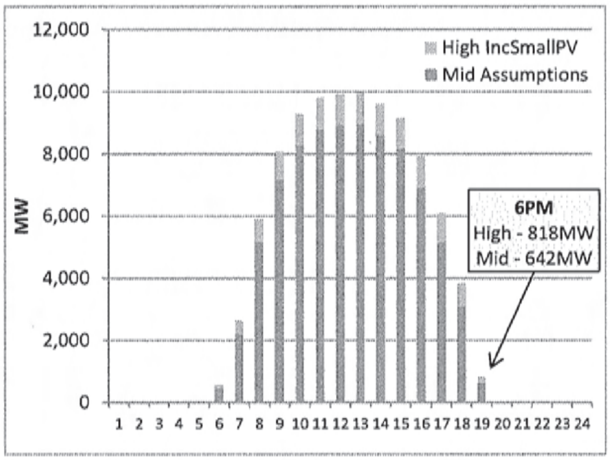


Figure 8: July 22 CA Solar PV output

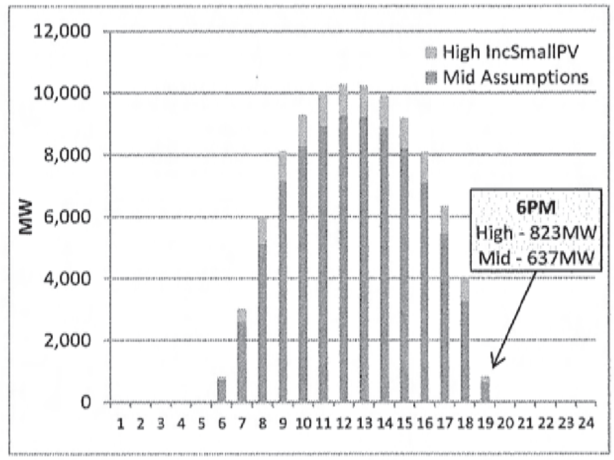


Figure 9: July Avg CA Solar PV output

Q. How do the hourly wind patterns align with the periods of shortage?

A. See Figures 10 and 11 below for wind output patterns. Wind facilities, like solar facilities, are also distributed throughout the state and derive some benefits in terms of consistent hourly output as a result of this geographic diversity. A larger disparity exists between the peak day, critical hour output and the July average at that critical hour – on July 22nd at 6 p.m. 948 MW of wind is available, while over the course of the month an average of 2,780 MW wind output is seen at that time.

To some extent, the tightest day – July 22nd – in the modeling is due in part to projected (i.e., modeled) lower output of the aggregate wind resource (relative to the July average) during this critical late afternoon/early evening period (seen in Figure 10). It is important to recognize that stochastic analysis beyond what has been done in this Track 2 can help to analyze the extent to which lower wind output during critical hours during the peak summer months occurs concurrently with peak load days. It is notable that the *average* pattern during July (as seen in Figures 10 and 11)is for wind to ramp up from midday on, while solar output is ramping down.

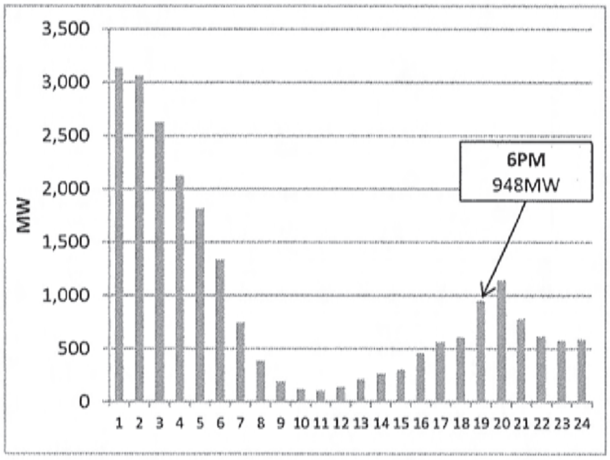


Figure 10 : July 22 CA Wind output

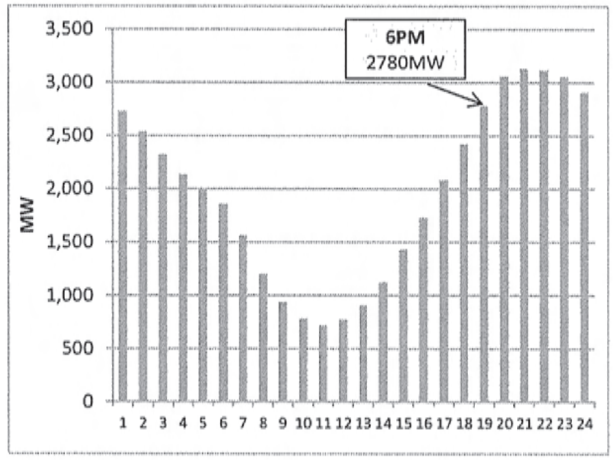


Figure 11: July Avg CA Wind output

Q. How to the combined hourly wind and solar patterns align with the periods of shortage?

A. Figure 12 shows the combined wind and solar output on the peak day. On the peak day at the critical hour, wind and solar resources combined represent 1,589MW of capacity in the base case, and 1,766MW when high incremental small PV resources are used.

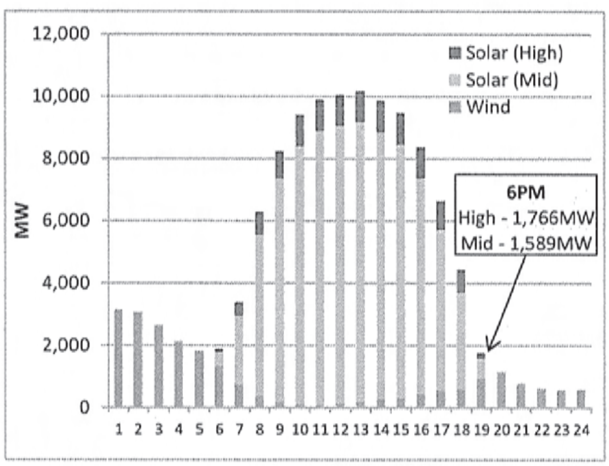


Figure 12 July 22 CA Wind + Solar Output

Q. How is DR utilized throughout the month of July?

A. DR is only actually called upon for energy purposes for a few hours on July 22nd, the day of identified shortage in the base case. The High PV case significantly reduces the amount of DR that must be called on July 22nd, from a total of 6,480 MWh to 4,700 MWh of total usage.

Throughout the month, DR is used for reserve provision at levels of approximately 100 to 300 MW in the hours between noon and 6 p.m. Figures 13 through 16 show the patterns of

DR output during all of July, and on just the peak day, for the CAISO base case and for selected ORA Scenarios.

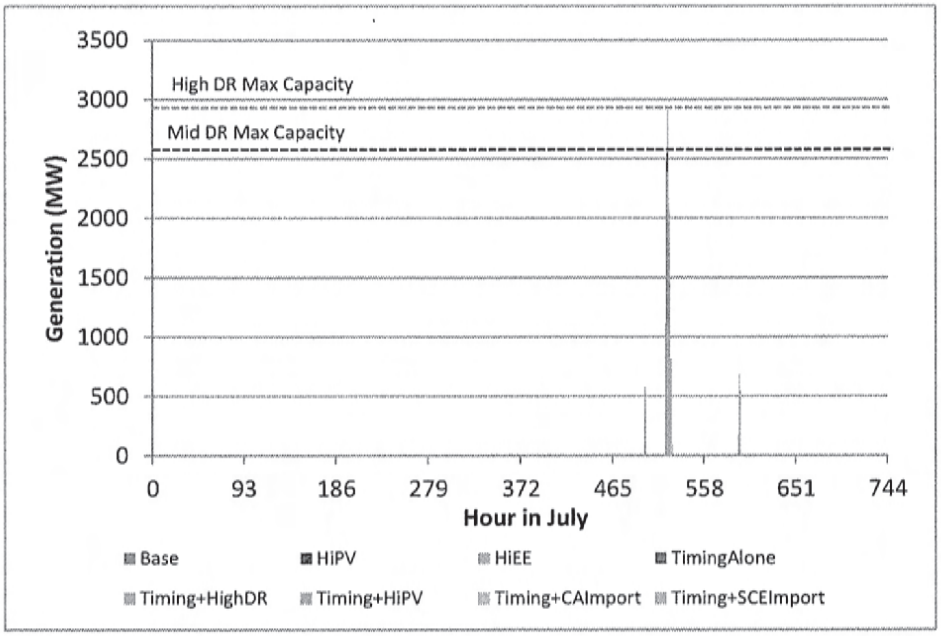


Figure 13: DR Generation in all hours of July

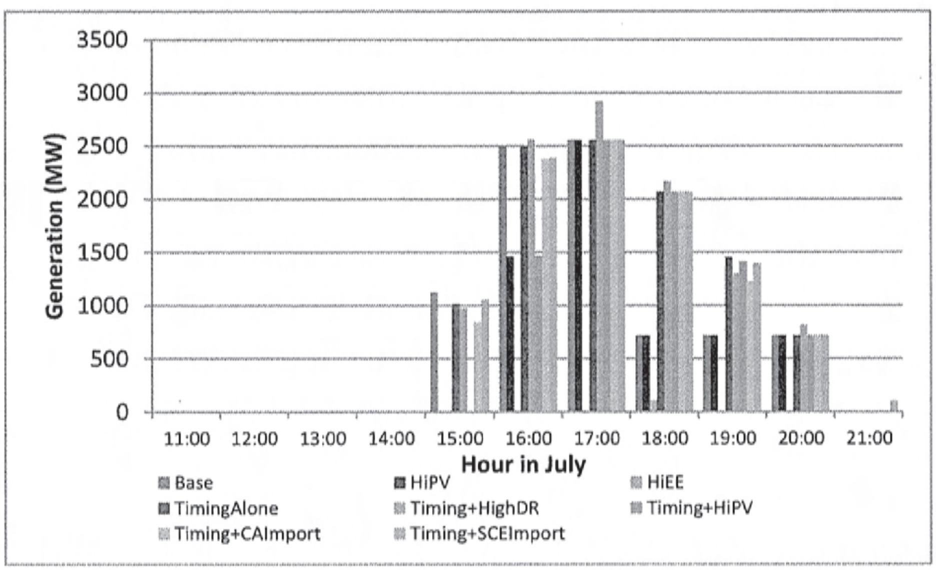


Figure 14: DR Generation on July 22

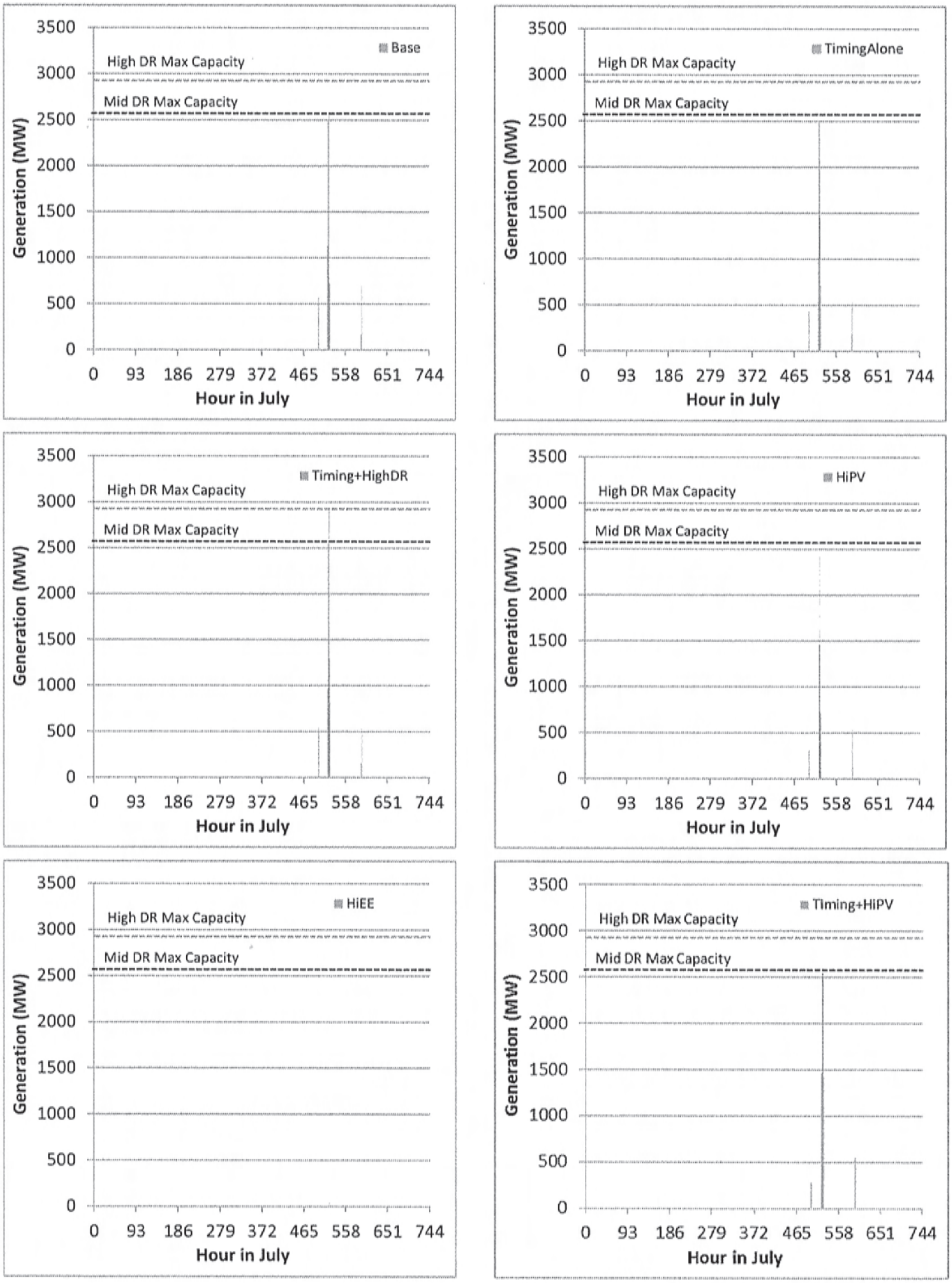


Figure 15: July DR utilization for selected ORA Scenarios

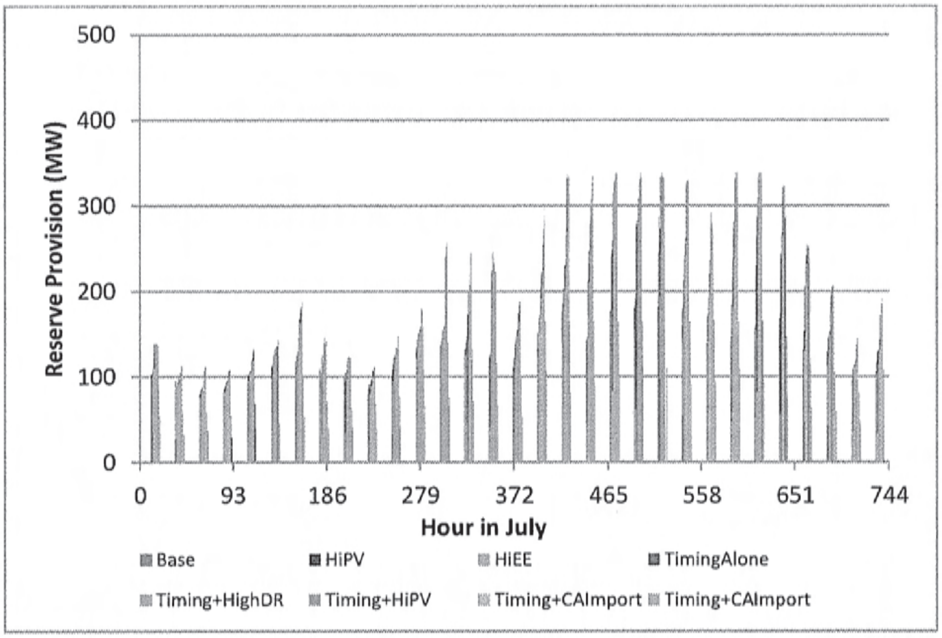


Figure 16: DR Reserve Provision all hours of July

As is seen in Figures 13 through 15, on critical days, DR ramps up to maximum output in the critical hours, limited in the base scenario only by the model's input constraint, which reduces DR output after 5 p.m. This "calling" or dispatching of DR, understandable given that prices spike higher during critical hours of the peak day, illustrates the critical role that limited use resources, especially DR, can play in ensuring reliable system operation during the extreme stress periods for the modeled system. We note that this extreme stress occurs on just one day in the modeled base case.

As seen in Figure 16, DR provides ongoing reserve capability during essentially all afternoon daytime hours of the month.

<u>Resource Outages During Peak Summer Month</u>

Q. What resources are not available during any part of the peak summer month, July, in the base case? Please comment.

A. Total modeled outage levels in July vary between 777MW and 4,236MW. The day where shortage hours were evident, outages peak at 3,822MW. At 6 p.m. when the system is highly constrained, this is reduced to 2,241MW. Incentives for RA performance could reduce projected summer peak month outages.

Several major units are out on the peak day in the base cases modeling, including the Palmdale, High Desert, and El Segundo 7 combined-cycle plants in the SCE territory, and Unit 1 at La Paloma in PG&E territory. Given sufficient demand and resource forecasting, coupled with RA incentives[20] to reduce outages, these four units alone represent 1,860MW of capacity that, when combined with improved availability of demand response resources, could eliminate the shortage on July 22.

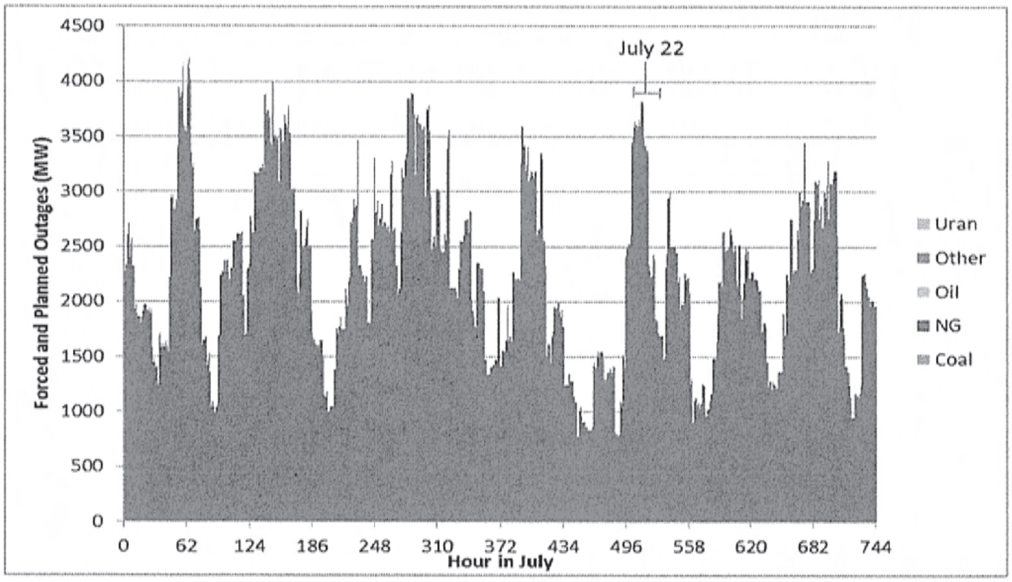


Figure 17: Modeled CA Outages in July 2022

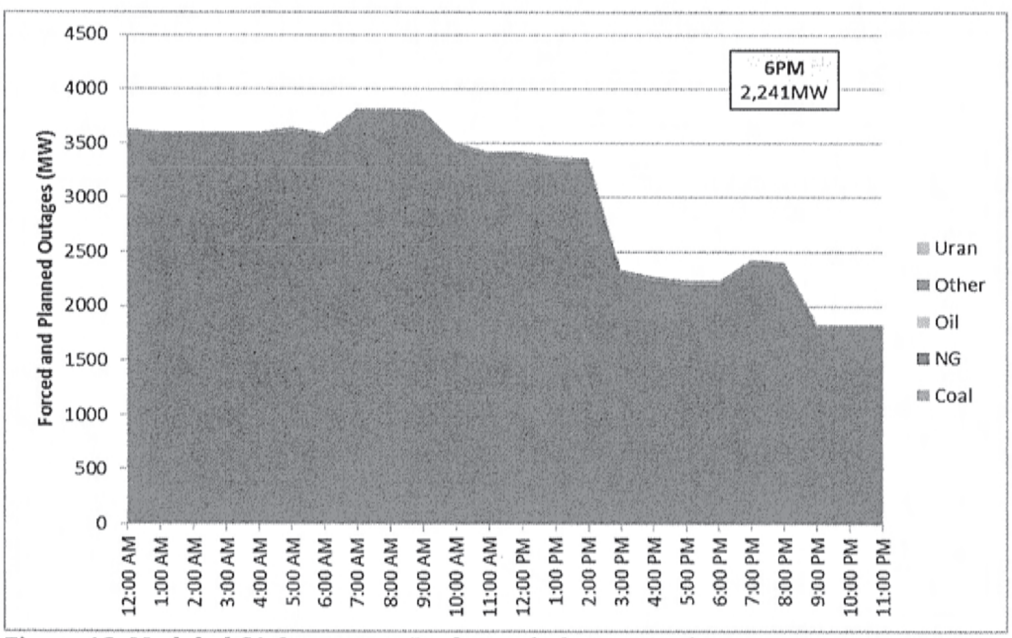


Figure 18: Modeled CA Outages on Peak Day (July 22, 2022)

[20] The RA construct is undergoing possible change to incorporate the value added of flexible units, and possibly increasing the RA obligation period beyond 1 year. Those changes could increase incentives to improve performance during peak periods.

ADDITIONAL DISCUSSION

Procurement Timing and Mechanisms

Q. Is advance procurement of fossil or preferred (EE, DR, PV, CHP) resources called for based on the Track 2 analyses you've conducted?

A. Both preferred and fossil resources require some form of advance procurement to ensure their deployment when those resources are needed. The exact timing depends on a number of variables. Continued use of the mechanisms in place to obtain preferred resources is sensible, though advancing funding commitments for those resources through the LTPP process could better secure their eventual deployment.

Advanced procurement of fossil resources (the resource of last choice in the state's loading order) would only be needed eight years out (2014 to 2022)[21], or even six years out (2014-2020)[22] if a) the resource need net of the effects of anticipated, realizable preferred resource procurement was likely to equal or exceed the "shortage" amount indicated, and b) there was no mechanism in place to obtain additional resources – either preferred or not - beyond those modeled as being available (in the inputs to the model run results shown in Tables 1 and 2).

Neither of these conditions has been met. The resource need superficially indicated by "shortage" amounts is not certain; we only know that the modeling results show a shortage for a few hours on the extreme peak day. Mechanisms exist, both market-based and otherwise, to obtain additional resources closer-in-time to periods that may exhibit shortage.

Those mechanisms include deployment of even greater levels of preferred resources than is reflected by the inputs used for the ORA Scenarios – especially demand response resources for very infrequent deployment, and market-based actions to increase capability available from existing units and/or reduce the incidence of forced or planned outage that is reflected in the model's inputs. While less likely, generic market mechanisms still exist that could lead to new plant construction arising from the existence of CAISO's spot energy and ancillary markets[23], and the existence of the resource adequacy construct for the IOUs.[24]

Base Case vs. TPP Forecasts as Basis for Procurement Decisions

Q. What are the key differences between the base case and the TPP case modeling assumptions?

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[21] CPUC decision on Track 2 in 2014.

[22] OTC resources retire by 2020.

[23] Those markets continue to undergo refinement to reflect the increasing value of capacity that exhibits flexible operating characteristics. Such refinement includes CAISO's changes to the energy market to incorporate a flexible ramping constraint into the unit commitment and dispatch provision, and changes to intertie scheduling timeframes in accordance with FERC's Order 764.

[24] The RA construct is also undergoing possible change to incorporate the value added of flexible units, and possibly increasing the RA obligation period beyond 1 year. Those changes would increase incentives for market-based development of new resources.

A. The TPP and base case use different assumptions for gross load ("counterfactual load"[25]), incremental EE projections, incremental PV assumptions, and DR assumptions. The TPP scenario uses a 1 in 5 peak load forecast[26], and the base case uses a 1 in 2 peak load forecast[27]. The TPP case uses a low incremental EE, and zero incremental PV, and the base scenario uses a mid incremental EE and a mid incremental PV. The TPP and base cases use the same projections for incremental CHP (zero), embedded self-generation (both PV and non-PV), and non-event based DR. In total, with the combined differences in projections for gross load, incremental EE and incremental PV, the TPP scenario sees a managed net demand that is 4,464 MW higher than the base case managed net demand.

Q. Is it reasonable to consider a higher, gross load forecast such as the 1 in 5 forecast, when assessing procurement needs?

A. Possibly. This element of the overall managed net demand is reasonable as a sensitivity to the base case demand. However, the CPUC has historically based resource procurement decisions for system needs on the 1 in 2 forecast peak, not the 1 in 5 forecast peak.

Q. Is it also reasonable to consider lower levels of EE, and lower levels of PV – as the TPP does?

A. Yes, but again as a sensitivity. However, it is notable that the TPP case combines all of these elemental differences into a managed net load that essentially represents an extreme sensitivity, based as it is on three components with low or zero value relative to the base case.

Q. Can you comment on the reasonableness of basing system capacity procurement decisions on either the base or the TPP case?

A. Yes. The 1-in-2 peak load forecast of the Base scenario is more appropriate for system capacity need determination than the Replicating TPP's 1-in-5 peak load forecast. The Resource Adequacy program uses average weather (1-in-2) and then adds a reserve margin which, in part, provides the cushion should hotter than average weather occur. The Commission's use of a 1-in-10 peak load forecast, for the purposes of determining local capacity requirements, is reasonable because local regions may well experience a 1-in-10 peak load. However, for system capacity needs, basing procurement decisions on anything more than a 1-in-2 peak load forecast could lead to an over-procurement of resources because it is unlikely that the 1 in 5 peak load level would be seen coincident across all CAISO region load areas at the same time.

<u>Track 1, Track 4, and OTC Retirement Assumptions</u>

Q. How are assumptions concerning new resources authorized by Track 1, and under consideration in Track 4, reflected in the Track 2 modeling?

[25] This is the term used in the CPUC Scenario Tool spreadsheet.

[26] Form 1.5c.

[27] Form 1.5b.

A. Some of the authorized Track 1 resources are included in the CAISO base case Track 2 modeling. Notably, Track 1 preferred resources are excluded (except as is already present in the modeled assumptions) – only the storage and some of the authorized gas-fired resources are considered in the CAISO base case. The modified ORA Scenarios include greater levels of preferred resources essentially accounting for Track 1 authorizations. Table 4 below shows which Track 1 authorizations are included, and which are excluded. No resources potentially available from Track 4 authorizations are included or considered except in one sensitivity, ORA Scenario 9. We note that Track 4 resources that may be authorized can be subtracted from any Track 2 need, but a critical caveat is necessary: 1) if Track 4 authorization (or results arising from anticipated 2013/14 transmission planning process (TPP) efforts) includes reactive and/or transmission system support that allows the California import limit to be increased, increased levels of imports (from existing external systems) can directly make up part of any residual Track 2 need.

	CC	CT	Storage	Tr. 1 Preferred Resources
SDGE	-	300	-	Excluded
SCE	900	100	50	Excluded
Big Creek/Ventura	Excluded	Excluded	NA	Excluded

Table 4: Track 1 Resources reflected in the Track 2 Modeling

Q. How are OTC resources treated in the CAISO and ORA Scenario modeling?

A. All OTC resources are assumed retired for the 2022 case. No inclusion of any potential extension of retirement date is considered.

Q. What effect could an extended retirement date have on Track 2 need?

A. Any extended retirement dates for any OTC resource would tend to reduce the Track 2 need by roughly the level of output of the OTC resource.

Q. Please discuss the role, if any, of possible OTC retirement date extension for certain plants.

A. Extension of OTC retirement dates could serve as an important insurance policy, cost avoidance measure, or a contingent planning approach, for the CAISO region. Under most scenarios with successful preferred resource deployment, capacity output from OTC units with an extended retirement date might only be needed for very brief periods, if at all. Total air emissions from OTC units whose retirement was extended for reliability reasons would likely be very low as generally they would not be needed for either energy or ancillary service requirements.[28] To some extent, OTC retirement extension could serve as a "bridge" to a period when some combination of increased transmission capacity and/or

[28] The California Air Resources Board (ARB) and the State Water Resources Control Board (SWRCB) may allow, or be more open to, an OTC extension intended only as an extreme day backup, with extremely limited or no cooling water withdrawals and air emissions. Certain OTC units could be fully offline (i.e., mothballed) for 9 months, available as a backup only for predicted extreme peak days during the summer.

increases in preferred resource availability, including storage, would more likely be in place. OTC extension could serve as an alternative to SCE's Track 4 "contingent planning" for gas-fired resources near or at Johanna and Santiago substations, or SDG&E's "Energy Park" considerations.[29] This testimony does not address the economic ramifications of this alternative insurance policy, vs. other approaches.

Critical Periods for System Resource Need

Q. What do the modeling results reveal concerning critical periods for system need, especially those periods when "flexibility" in resource deployment is most warranted?

A. As seen in the modeling results (ours and CAISO's) and as noted in the above sections, critical periods are likely to be limited to extreme peak days in the summer; and the concern is essentially a generic capacity constraint, not a flexibility problem. Thus, a relatively broad array of resources could be available to address such concerns. Such resources do not necessarily need to be specifically identified, financed and planned for construction 7 to 9 years in advance. There is no particular ramping or "flexibility" concern during any base scenario period except on the peak summer day. There are no RA concerns whatsoever in the high DG/DSM scenario. This illustrates that even with the concern registered about spring afternoon periods, e.g., (the "duck graph" issues)[30] modeling reveals that the system as a whole is actually quite robust, and is potentially severely stressed (based on current projections)only during periods of peak summer loading. This is understandable – there is a sizable gas, hydro, and import supply resource base available in CAISO and California to address system-level ramping requirements, even with the OTC retirements. The main difference between the resource adequacy concern that is revealed in the base case modeling and more traditional summer peaking period RA concerns is that the critical hour is shifted ahead a few hours, from the historical 2-4 PM period, to the slightly later, late afternoon/early evening period coincident with projected PV output decline.

Import Considerations

Q. What statewide import limits are used in the Plexos modeling?

A. The model uses summer peak CA imports of 13,865 MW in the base and TPP cases. CAISO's high DG/DSM case uses a limit of 14,053 MW. This limit binds at critical times, and contributes to the shortage in the key July hour.

Q. What other transmission limits are used in the model?

A. The imports into SCE and the imports into San Diego are limited to a fraction of the SCE service area total load via an economic "penalty" incorporated into the model if a violation occurs.

Q. Please discuss the import limitations.

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[29] Track 4 testimonies of SCE and SDG&E.

[30] Numerous presentations by stakeholders have used or cited the so-called "duck graph" when highlighting the potential late afternoon/early evening ramping concerns that may exist when the state has more solar resources online. For example, as presented by the CAISO during the February, 2013 en banc "Capacity Summit".

A. Generally, the import limitations contribute to restriction of the ability of the CAISO system to see zero modeled shortage on the peak day, under CAISO base and some ORA Scenario conditions, without adding "residual" capacity. Critically, transmission system improvements and/or increased generation in the LA Basin/SDG&E area per Track 4 requirements could increase the effective transmission limit[31], and allow a reduction in any Track 2 need determination.

California has always depended on imports for reliability purposes, and should continue to maximize the utilization of its interconnected transmission system to ensure sufficient renewable integration resources. With the ongoing improvements in WECC-wide coordination efforts[32], CAISO and CA as a whole will benefit and these benefits could extend to increases in the overall level of transmission import availability.[33] This would allow CAISO to tap into existing resources in the WECC to increase reliability during extreme days – and reduce potential conventional generation procurement needs to address very infrequent periods with tight system resources.

CAISO Track 2 Modeling

Q. Please comment on CAISO's use of Track 2 scoping memo assumptions.

A. CAISO's implementation of the Plexos model appears to be mostly in line with the Track 2 scoping memo assumptions, with a few exceptions. CAISO has excluded Track 1 preferred resources (except as they may overlap with scoping memo assumptions). CAISO has also not included Track 1 Big Creek / Ventura fossil resources. CAISO has not supported the 11 a.m. – 5 p.m. window it gives DR for the base case, although they have also run sensitivities exploring an expanded availability window. We believe the inputs they use for such sensitivities are more appropriately represented in the base case, particularly for the hours immediately following the modeled shortage window on the peak July day. Many of our ORA Scenarios include this "DR availability" shift to 1 p.m. -7 p.m.

Q. Please comment on CAISO's results.

A. We have replicated CAISO's base case results by running the Plexos model on our own systems. Last minute corrections to the model increased the most extreme shortage values in their base case from 1,912 MW to 2,612 MW. We have incorporated the same corrections in our modeling. A small amount of avoided system losses that would accrue from solar PV resources that are "behind-the-meter' may not be accounted for in the modeling.

[31] This is seen in the material made available by CAISO on how the Southern California Import Transmission (SCIT) limited is affected by numerous factors; and is evidenced by the values used by CAISO in its modeling of the transmission limits for the base case, vs. the high DG/DSM case.

[32] For example, PacifiCorp and the CAISO have signed a Memorandum of Understanding that could result in PacifiCorp resources being available to be directly dispatched in the CAISO energy markets, and continued efforts to establish a WECC-wide energy imbalance market to improve the scheduling and coordination of power flows across the western regions. Some of this coordination is driver by the FERC's rulings (Order 764) on improved transmission scheduling between balancing areas.

[33] Many factors would influence the extent to which California path import capacity could be better utilized with existing assets, or could be increased with increased transmission capacity.

CONCLUSIONS/RECOMMENDATIONS

Q. What is your overall conclusion/recommendation about the need for new resources in the CAISO region by 2022, to provide sufficient system flexibility?

A. We find that deploying feasible, and reasonable, levels of preferred resources will ensure sufficient system flexibility in 2022 while integrating statutory levels of renewable resources. EE and DR resources in particular are critical, at the highest levels that are economically beneficial. Also, any increases in PV program procurement towards levels that reflect "high" incremental PV would benefit system needs by reducing shortages during the critical period.

In our opinion no additional fossil-fueled resource procurements are required at this time because the duration and pattern of modeled "shortage" is minimal and sufficient time exists to develop incremental preferred resources that could be available to fill any gap. Those resources include, in particular, targeted levels of demand response beyond that considered in the "high DR" cases that need be available on a very infrequent basis.

Select OTC resources can serve as "insurance" and can be allowed to retire, potentially on schedule, if preferred resource procurement develops on time; if preferred resource development timelines falls short, OTC resource extension can help bridge the gap until preferred resource goals are reached.

We also note that transmission system investment should be expeditiously considered, especially low-hanging-fruit such as the Mesa Loop-in, and other transmission and reactive supply alternatives noted in SCE's Track 4 testimony and indicated in the LA Basin and San Diego area reliability plan[34]. These resources can help to improve flexibility by allowing more resources to be dispatched under tight conditions in the region.

Q. Does this conclude your testimony?

A. Yes.

[34] Preliminary Reliability Plan for LA Basin and San Diego, Draft, August 30, 2013. Prepared by Staff of the California Public Utilities Commission, California Energy Commission, and California Independent System Operator.

WITNESS QUALIFICATIONS – ROBERT M. FAGAN

Q. Please state your name, position and business address.

A. My name is Robert M. Fagan. I am a Principal Associate with Synapse Energy Economics, Inc., 485 Massachusetts Ave., Cambridge, MA 02139. I have been employed in that position since 2005.

Q. Please state your qualifications.

A. My full qualifications are listed in my resume, on the following pages. I am a mechanical engineer and energy economics analyst, and I have examined energy industry issues for more than 25 years. My activities focus on many aspects of the electric power industry, especially economic and technical analysis of electric supply and delivery systems, wholesale and retail electricity provision, energy and capacity market structures, renewable resource alternatives including on-shore and off-shore wind and solar PV, and assessment and implementation of energy efficiency and demand response alternatives.

I hold an MA from Boston University in Energy and Environmental Studies and a BS from Clarkson University in Mechanical Engineering. I have completed additional course work in wind integration, solar engineering, regulatory and legal aspects of electric power systems, building controls, cogeneration, lighting design and mechanical and aerospace engineering.

Q. Have you testified before the CPUC before?

A. Yes, in Track 1 of this proceeding, and in the A.11-05-023 SDG&E need case. I have also testified in numerous state and provincial jurisdictions, and the Federal Energy Regulatory Commission (FERC), on various aspects of the electric power industry including renewable resource integration, transmission system planning, resource need, and the effects of demand-side resources on the electric power system.

Q. On whose behalf are you testifying in this case?

A. I am testifying on behalf of the California Public Utilities Commission's Office of Ratepayer Advocates (ORA).

WITNESS QUALIFICATIONS – PATRICK LUCKOW

Q. Please state your name, position and business address.

A. My name is Patrick Luckow. I am an Associate with Synapse Energy Economics, Inc., 485 Massachusetts Ave., Cambridge, MA 02139. I have been employed in that position since I started work at Synapse in 2012.

Q. Please state your qualifications.

A. I am an Associate at Synapse, with a special focus on calibrating, running, and modifying industry-standard economic models to evaluate long-term energy plans, and the environmental and economic impacts of policy/regulatory initiatives.

Prior to joining Synapse, I worked as a scientist at the Joint Global Change Research Institute in College Park, Maryland. In this position, I evaluated the long-term implications of potential climate policies, both internationally and in the U.S., across a range of energy and electricity models. This work included leading a team studying global wind energy resources and their interaction in the Institute's integrated assessment model, and modeling large-scale biomass use in the global energy system.

I hold a Bachelor of Science degree in Mechanical Engineering from Northwestern University, and a Master of Science degree in Mechanical Engineering from the University of Maryland.

Q. Have you testified before the CPUC before?

A. No.

Q. On whose behalf are you testifying in this case?

A. I am testifying on behalf of the California Public Utilities Commission's Office of Ratepayer Advocates (ORA).