2021

SUMMER LOADS AND RESOURCES ASSESSMENT

California ISO

May 12, 2021

Table of Contents

I. EXECUTIVE SUMMARY

The *2021 Summer Loads and Resources Assessment* provides an assessment of the expected supply and demand conditions this upcoming summer for the California Independent System Operator (ISO) balancing authority area. The Assessment considers the supply and demand conditions across the entire ISO balancing authority area, and to a more limited extent, the entire Western Electricity Coordinating Council (WECC).

The ISO anticipates supply conditions in 2021 to be better than 2020, but continues to see potential challenges in meeting demand during extreme heat waves. Such scenarios that affect a substantial portion of the Western Interconnection and cause simultaneously high loads across the West would reduce the availability of imports into the ISO balancing authority area. Improvements to supply conditions in 2021 are largely driven by the addition of new resources coming online as early as this summer. However, while forecasted load levels remain virtually unchanged under normal conditions, a second year of significantly lower-than-normal hydro conditions and an increased possibility of extreme weather events indicate the ISO may still face challenges in meeting load this summer. Recent data from NOAA[1], for example, confirms that conditions in the West are getting hotter and drier.

Capacity shortfalls this summer may be mitigated by additional extraordinary measures accessed under extreme or emergency conditions to limit the risk of actual firm load shedding. Since September 2020, the ISO has been working to enhance its operational procedures to operate reliably this summer, including the ability to access these extraordinary measures. The ISO will continue to find and act on such opportunities as available and necessary, but is guardedly optimistic regarding its operations this summer given the measures already taken, including greater coordination with the State and regional entities. Conservation during extreme events will again be critical to avoid shedding load. The ISO and State entities have taken significant measures to inform consumers in a timely manner through the Flex Alert campaign to conserve energy when requested to avoid outages.

Preparation for Summer Operation

Preparing and publishing the Assessment report and sharing the results with industry participants and stakeholders is one of many activities the ISO undertakes each year to prepare for summer system operations. Given the widespread heat wave events of 2020 that led to firm load shedding in the ISO balancing authority area, the ISO, State entities, and others have taken a host of measures to improve system preparedness and performance in 2021. These include pursuing and approving procurement of additional resources, ensuring existing resources are retained in service, and improving operational readiness and measures to access resources or load reductions that can be implemented when faced with the risk of shortfalls. Those reforms, modifications and other actions were

[1] https://www.noaa.gov/news/new-us-climate-normals-are-here-what-do-they-tell-us-about-climate-change

discussed publicly most recently at a California Energy Commission workshop on summer 2021 reliability[2] held on May 4, 2021.

This Assessment evaluates the effectiveness of expected supply including established demand response programs to meet system load and reserve requirements. The report is not designed to evaluate the effectiveness of newly developed, pilot, voluntary or extraordinary measures[3] including more effective Flex Alert and conservation measures that may be deployed when the system is experiencing extreme or emergency conditions. Nonetheless, these additional measures can be highly effective mitigation tools to avoid having to rely on firm load shedding during extreme events.

Other routine preparatory activities include coordinating meetings on summer preparedness with the WECC, California Department of Forestry and Fire Protection (Cal Fire), natural gas providers, transmission operators and neighboring balancing areas. For 2021, the ISO engaged these entities in a tabletop exercise where participants walked through scenarios that started seven days out from a peak load day and proceeded through to the potential need for shedding load in real time. The exercise practiced using the ISO Alerts, Warnings and Emergency procedures, communications protocols, recent policy changes, and contingency reserve management procedures. The ISO's ongoing coordination activities with these entities helps ensure that everyone is prepared for the upcoming summer operational season.

[2] CEC Integrated Energy Policy Report Joint Agency Workshop on Summer 2021 Reliability - Reliability Outlook, May 4, 2021, available at: https://www.energy.ca.gov/event/meeting/2021-05/session-1-iepr-joint-agency-workshop-summer-2021-reliability-reliability

[3] Example is the CPUC newly developed Emergency Load Reduction Program (ELRP)

II. 2021 SUMMER ASSESSMENT

The *2021 Summer Loads and Resources Assessment* provides an assessment of the expected supply and demand conditions this coming summer for the California Independent System Operator (ISO) balancing authority area. The Assessment forecasts this summer's supply and demand and identifies potential operational issues using information held by the ISO, third-party modeling tools, and public information from various state agencies, generation and transmission owners, load-serving entities, and other balancing authorities (BAs). The Assessment considers the supply and demand conditions across the entire ISO balancing authority area and, to a more limited extent, the entire Western Electricity Coordinating Council (WECC).

The Assessment is based on the availability of resources accessible through normal market operations. It does not take into account extraordinary measures taken under extreme or emergency conditions to mitigate the risk of actually having to shed or curtail firm load. Therefore, capacity shortfalls identified in this report are more indicative of the likelihood of needing to rely on those extraordinary measures, rather than the actual risk of loss of firm load.

In addition to the probabilistic analysis that the ISO prepared for the Assessment, consistent with past summer assessments, the ISO also performed a deterministic stack[4] analysis of the resource procurement targets and minimum resource needs under the California Public Utilities Commission (CPUC) Resource Adequacy program, and provided those results in this Assessment to complement the probabilistic analysis. This stack analysis focuses on resources and demand available at the 8 p.m. period during high-load days that is emerging as the period of highest risk as daily solar output drops off. The stack analysis provides an additional perspective on the amount of capacity the ISO is expecting to be available for summer 2021 and the level of reliability anticipated under various load levels and import conditions.

The body of this report consists of a discussion of the critical parameters that affect the assessment of forecast reliability, and the analysis and key observations that drive the ISO's conclusions. Each of those topics is discussed in turn.

Probabilistic Study Key Parameters

Hydro Conditions

California hydro energy supply will be significantly lower than normal during 2021. California is in a second consecutive year of below normal precipitation statewide. Snow water content for 2021 peaked at 60 percent of normal, similar to the 63 percent level for 2020. However,

[4] A stack analysis focuses on a particular point in time, adding up or "stacking" the resources expected to be available at the point in time and comparing the total to the demand side expectation at that time of day including a planning margin for reserves, variations from forecast load levels, and unanticipated, unplanned forced outages to the resource fleet.

to date, 2021 runoff from snowmelt has occurred earlier than in 2020, which was earlier than normal itself, and the average water levels of large reservoirs for 2021 was 70 percent of normal, which compared to 101 percent of normal in 2020. The ISO used Northwest River Forecast Center projections as an indication of potential imports into California from the Northwest, and The Dalles Dam on the Columbia River is generally used as a representative indicator. The current April to September reservoir storage projection at The Dalles Dam Columbia River is 89 percent of average.

Peak Demand Forecast

The ISO 2021 1-in-2 peak demand forecast[5] is 45,837 MW, which is 0.2 percent above the 2020 weather normalized peak demand of 45,742 MW.[6] A comparison of the ISO 2021 weather driven peak demand forecast levels to those for 2020 are shown in *Table 1*. The 1-in-2 and 1-in-5 forecast levels are virtually unchanged for 2021, however the 1-in-10 forecast is significantly higher than the 2020 forecast. The higher loads associated with a 1-in-10 weather event are attributable to including last year's extreme weather events in the historical weather database that is used to develop the range of load forecasts. This changed the high temperature end of the weather distribution profile such that the probability of the historical extreme heat events are now within the range of a 1-in-10 weather event. The ISO 2021 1-in-10 peak demand forecast is 50,968 MW – 11 percent higher than the 1-in-2 forecast level, a significant increase from the 6 percent incrementally higher demand of the 2020 1-in-10 demand forecast over the 2020 1-in-2 forecast.

Table 1

2021 Peak Demand Forecast Compared to 2020

	1-in-2	1-in-5	1-in-10
CAISO 2020 Forecast	45,907	47,755	48,457
CAISO 2021 Forecast	45,837	47,747	50,968
Difference (MW)	-70	-8	2,511
Difference (%)	-0.2%	0.0%	5.2%

System Capacity

The ISO projects system capacity of 49,583 MW in June, 50,734 MW in July, 50,010 MW in August, and 47,385 MW in September for summer 2021. The decline of available capacity

[5] A 1-in-2 peak demand forecast is the forecast of peak demand that is statistically expected to be reached once every two years. Similarly, a 1-in-5 and 1-in-10 peak demand forecasts are statistically expected to be reached once every five years and once very ten years, respectively.
[6] The weather normalized peak is a simulated amount of what the peak demand would have been under normal or 1-in-2 weather conditions.

from July to September results from the declining effective load carrying capability of solar and hydro generation. The declining effective load capability for grid-connected solar and hydro is primarily due to the shifting of peak loads to later in the day due to behind-the-meter solar generation, and declining hydro energy expectations, respectively.

From June 1, 2020 to September 1, 2021, approximately 3,961 MW[7] of installed capacity is expected to reach commercial operation: 1,613 MW is dispatchable and 2,348 MW is non-dispatchable.[8] During the same period, 81 MW of generation capacity will retire or be mothballed: 43 MW is dispatchable and 38 MW is non-dispatchable. The net of additions and retirements represents an increase of 3,880 MW, with a net increase of dispatchable capacity of 1,570 MW. While delays in expected new resource additions yet to achieve their commercial operation date are not anticipated, a delay in a significant amount of this capacity could impact the results of the Assessment.

Of the new resource capacity working to be operational for this summer, 1,493 MW is from battery energy storage systems (BESS) coming online by 9/1/2021. While not providing new energy generation, BESS enable surplus energy generated during periods of high solar production and energy generated during periods of lower energy prices to be stored and provided to meet system needs during the net peak period when solar production ramps down and is no longer available. BESS are able to provide system capacity, ancillary service and flexible capacity.

In addition to the gas-fired generation, hydro, and renewable generation described above, 1,218 MW of demand response resource capability available to the market reported in 2020 was carried forward into the 2021 analysis. Demand response is utilized when the simulation depletes all other available resources before meeting the load and ancillary service requirements.

Probabilistic Simulation Process and Results

The ISO developed a stochastic production simulation model employing the PLEXOS market simulation software to assess hourly operating conditions given the changing resource mix of higher penetration of variable renewable resources and fewer dispatchable conventional resources. The model assesses 2,000 unique randomly generated summer

7 New resource capacity was developed from the ISO Master File and the New Resource Implementation process to determine the anticipated commercial operation date of new resources expected to come online within the 2021 Assessment study period. The amounts were based on known information as of 3/24/2021. New resources from this process were cross checked against resources known by the CPUC to be sure all resources the CPUC is expecting were accounted for.

8 Non-dispatchable resources are technologies that are dependent on a variable fuel source and are modeled in PLEXOS as energy production profiles based on historical generation patterns. Non-dispatchable technologies include biofuels, geothermal, wind, solar, run-of-river hydro, and non-dispatchable natural gas.

scenarios of forecasted hourly load and renewable generation to assess the ISO's resource adequacy in system capacity, ancillary service, and flexible capacity on an hourly basis.

The Assessment considers how much capacity that can be obtained within 20 minutes – beyond the capacity serving load – remains available in each summer hour in each of the 2000 scenarios. This capacity is referred to as unloaded capacity[9], and it consists of any portion of online generation capacity that is not serving load or offline generation capacity that can come online in 20 minutes or less to serve load as well as curtailable demands such as demand response, interruptible pumping load, and aggregated participating load that can provide non-spinning reserve or demand reduction. The unloaded capacity includes system operating reserves. The ISO has further defined the Unloaded Capacity Margin (UCM) as the excess of the resources, available within 20 minutes or less, over the projected load expressed as a percentage on an hourly basis. Levels of UCM above the operating reserve requirement for any given hour (typically around 6 percent) signify that capacity is available beyond the requirement for operating reserves, which to the extent available, can be used during system contingencies.

The ISO performed base case and sensitivity analyses, modeling the system under conditions where imports are more favorable (base case), and modeling the system under conditions where imports are limited to the amounts typically procured to meet requirements of the Resource Adequacy (RA) program (sensitivity case). The results show an improvement in system supply conditions over 2020. However, the ISO system can still face challenges during more extreme load conditions. Both the base and sensitivity cases show a potential for challenging conditions when loads are more extreme, specifically at 1-in-10 and higher levels and particularly when availability of non-firm imports diminishes due to high heat events that encompasses areas beyond California's borders. Extreme heat waves that spread over a broader area than the ISO can lead to diminished availability of surplus energy for imports into the ISO. Extreme conditions could lead to requests for more aggressive voluntary load reductions and even shedding of firm load to maintain sufficient operating reserves.

Base Case Results

The lowest UCM from each scenario modeled is termed the Minimum Unloaded Capacity Margin (MUCM). The MUCMs of all 2,000 scenarios simulated are used to determine the probability of various capacity shortfall events occurring. In other words, by looking at the worst, lowest margin hour of each scenario, a single scenario showing a capacity shortfall event would result in a probability of shortfall of one in 2,000, regardless of how many hours within that scenario that the shortfall occurred. *Table 2* shows scenarios with extreme low operating reserves where the MUCM is at emergency levels (stage 2, stage 3)[10] and scenarios with unserved energy. The ISO system has a 6.4 percent probability of operating at stage 2 based on 128 scenarios having at least one hour that met the definition of a stage

[9] Generation capacity that is serving load is referred to as "loaded capacity".
[10] See System Alerts, Warnings and Emergencies Fact Sheet on the ISO webpage – http://www.caiso.com/informed/Pages/Notifications/NoticeLog.aspx

2 condition, a 4.8 percent probability at stage 3 based on 96 scenarios having one hour or more that met the definition of a stage 3 condition, and a 4.6 percent probability with unserved energy based on 91 scenarios showing one hour or more of unserved energy.

Table 2

Probability of system capacity shortfall for base case

System Capacity Shortfall	Shortfall Probability	Number of Shortfall Case
Stage 2	6.4%	128
Stage 3	4.8%	96
Unserved energy	4.6%	91

Demand response programs were utilized as needed to maintain a 6 percent operating reserve margin and would be fully utilized in cases where the operating reserve margin is below 6 percent. Should ISO system operating conditions go into the emergency stages, the ISO will issue a notice of potential load interruptions to utilities and implement the mitigation operating plan to minimize loss of load in the ISO balancing authority area described in the *Preparation for Summer Operation* section at the end of the *Executive Summary*. Whether actual interruptions would occur depends on the specific circumstances and effectiveness of the extraordinary measures.

To further assess resource adequacy for the summer period, the MUCM from each of the 2,000 scenarios are shown in *Figure 1*. The zero results are hours where the supply is less than demand, and represents the most extreme hours within the 2,000 scenarios considered.

Figure 2 shows the distribution of the MUCM less than or equal to 6 percent over the hours of the day in which they occurred. The solar generation profile anticipated during the 2021 summer peak day is shown to provide a reference related to the profile of the hours of highest risk. The MUCM less than or equal to 6 percent has the highest level of occurrences during hour ending 20 (i.e., 8:00 pm) and most occur during peak periods with significantly reduced or no solar generation.

Figure 1

ISO Minimum Unloaded Capacity Margin for base case

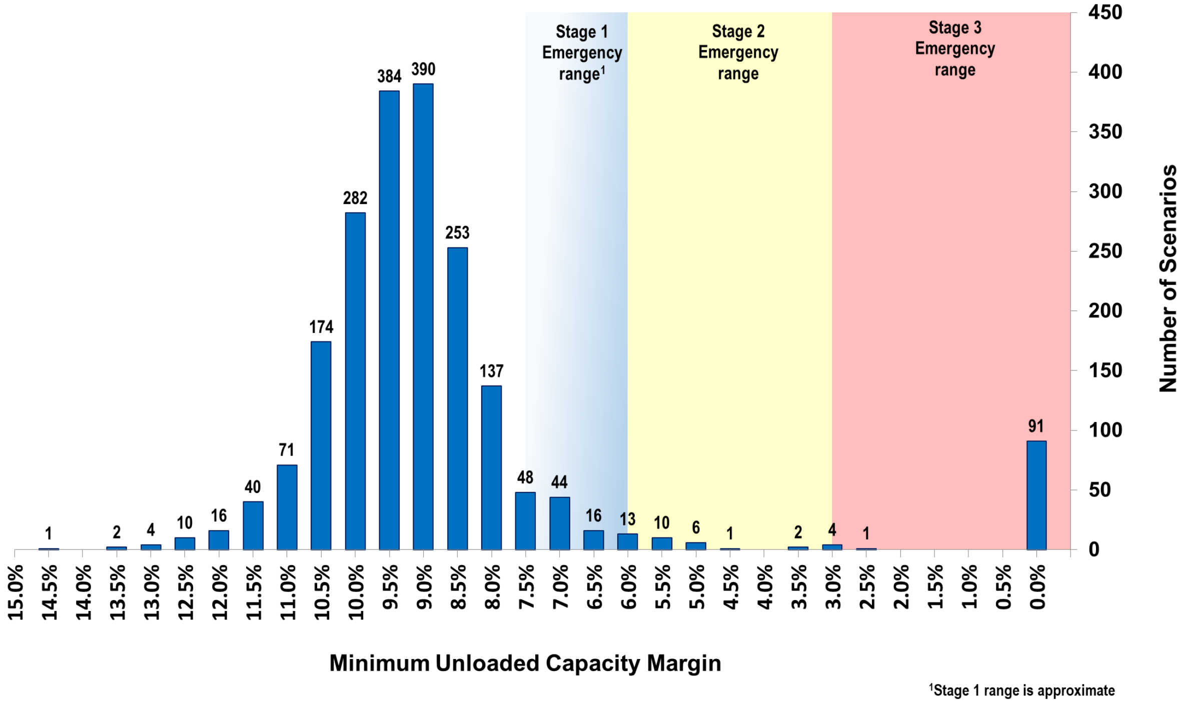


Figure 1 shows distribution of summer ISO MUCM for base case.

Figure 2

Occurrence hour of MUCM less than or equal to 6 percent and solar generation for base case

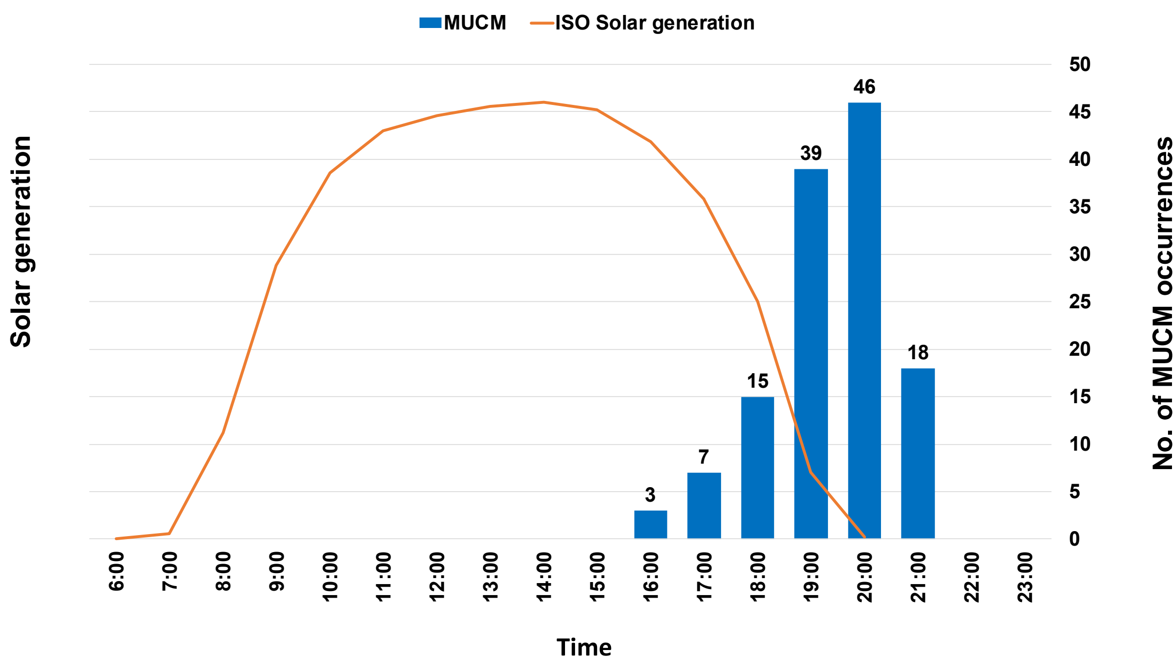


Figure 2 shows the occurrence hour of MUCM less than or equal to 6 percent and the solar generation

Figure 3 shows the amount of unserved energy – not accounting for the impact of mitigations – for each hour of unserved energy and the ISO load levels they occurred at. The maximum unserved energy is 6,514 MW in August. The ISO loads when unserved energy occurs range from 45,922 MW to 55,587 MW.

Figure 3

ISO loads versus unserved energy for base case

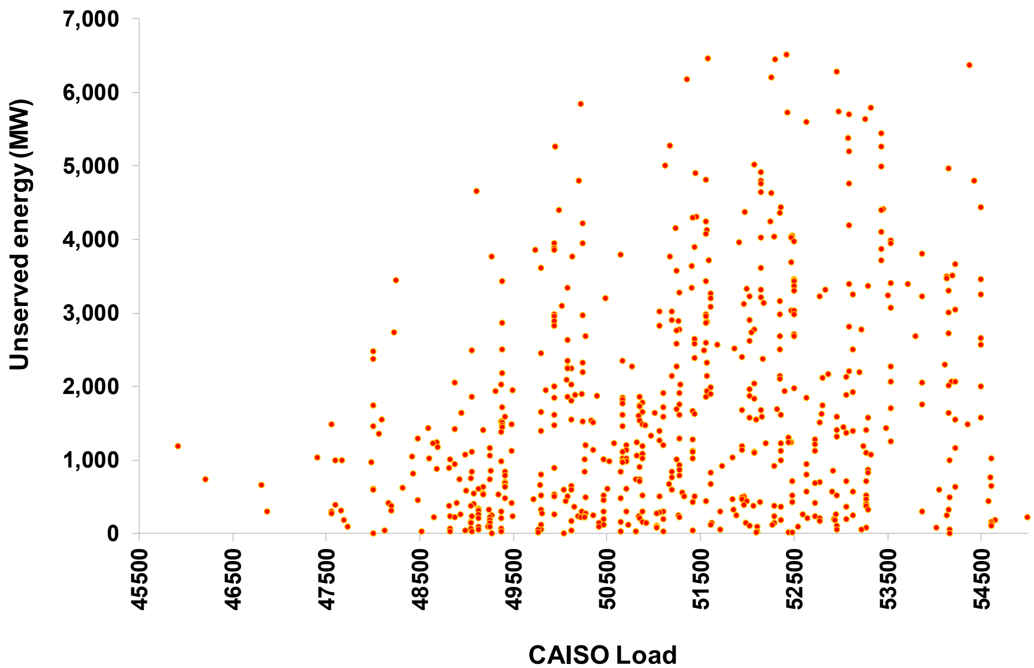


Figure 3 shows ISO load level versus unserved energy for base case.

Sensitivity Case Study

To understand the vulnerability of the ISO system under conditions where net imports are limited to the amounts typically procured to meet requirements of the RA program, the ISO performed a sensitivity case study with the ISO net imports capped at the 2015 – 2020 six year average RA import levels of: 3,922 MW in June, 5,340 MW in July, 6,095 MW in August, and 5,921 MW in September.

The sensitivity case simulation results indicate that the ISO system will have a 14.1 percent probability operating at a stage 2 emergency (281 scenarios produced at least one hour of potential stage 2), a 12.5 percent probability at stage 3 (249 scenarios produced an hour or more of potential stage 3), and a 12.4 percent probability with unserved energy (247 scenarios showed at least one hour of potential unserved energy), as shown in *Table 3*.

Table 3

Probability of ISO system capacity shortfall for sensitivity case

System Capacity Shortfall	Shortfall Probability	Number of Shortfall Case
Stage 2	14.1%	281
Stage 3	12.5%	249
Unserved energy	12.4%	247

Table 4 compares the probabilities of an ISO system capacity shortfall of the base case and the sensitivity case, revealing the criticality of net imports to the ISO during system peak hours at high load conditions. If the ISO is limited to the more conservative net import levels of the sensitivity case, the probability of having to shed firm load to maintain required operating reserves is significantly increased. This indicates that the ISO will be at the greatest operational risk during a late summer widespread heat wave that results in high ISO loads and low net imports due to high peak demands in its neighboring balancing authority areas, concurrent with the diminishing effective load carrying capability of solar resources and the wane of hydro generation.

Table 4

Probability of ISO system capacity shortfall

Base case compared to sensitivity case

Result	Base Case	Sensitivity Case
Stage 2	6.4%	14.1%
Stage 3	4.8%	12.5%
Unserved energy	4.6%	12.4%

Deterministic Stack Analysis

While assessing adequate resource procurement targets and minimum resource needs under the California Public Utilities Commission (CPUC) RA program, the ISO performed a deterministic stack analysis. In addition to the stochastic modeling described above, the ISO deterministic stack analysis provides an additional perspective on the amount of capacity the ISO is expecting to be available for summer 2021 and the level of reliability that is anticipated under various load levels and import conditions.

To maintain reliability, the ISO must comply with several North American Electric Reliability Corporation (NERC) and Western Electricity Coordinating Council (WECC) standards in real-time. BAL-002-WECC-2a requires the ISO to carry approximately 6 percent of expected load as contingency reserves. The contingency reserves required under BAL-002-WECC-

2a cannot be used for other types of operational needs other than contingencies unless the ISO is in an energy emergency alert. In addition, the ISO also requires unloaded capacity to meet operational needs like frequency response and regulation pursuant to BAL-003-2 and BAL-001-2. To assess the ISO's ability to maintain those reserve margins necessary for reliable service in real time operation, the ISO considered the capacity needs taking into account the overall outage rate of the existing fleet, which is currently about 7.5 percent. The ISO also based the deterministic assessment on meeting a 1-in-5 load forecast level. The combined effect of these requirements established a threshold need for a 17.5 percent margin above a 1-in-2 load forecast level.

The ISO's analysis consisted of two steps; first assessing the need for capacity required to meet the contingency provisions of BAL-002-WECC-2a, and then assessing the ability of existing and forecast resources to meet those needs in the summer of 2021. From an RA planning perspective, the ISO considers that a 17.5 percent margin applied to a 1-in-2 load level is necessary to provide reliable service pursuant to the contingency reserve provisions. This consists of the 6 percent operating reserve contingency requirement set out in the standard, allowance for 7.5 percent for forced outages, and a 4 percent margin for higher loads than an average 1-in-2 system load forecast. The 4 percent allowance for load accommodates forecast loads up to a 1-in-5 level above the 1-in-2 forecast used as a baseline.

Figure 4 shows the result of the deterministic stack analysis for the month of September, 2021, at 8 pm, the month and hour of the greatest supply risk. The amount of new resources shown in *Figure 4* are based on a CPUC presentation[11] that shows 2,388 MW of expected new capacity coming online between August 1 2020 and August 1, 2021. The 2,388 was adjusted to 2,230 by removing the solar resource capacity not associated with a storage component to account for the 8 pm time of day when solar generation is not available. The three bars of stacked resources portray three scenarios of progressively increasing resource amounts. Moving from left to right, the first bar represents resources similar to the stochastic sensitivity case, where imports are limited to the average of the last six-years of RA imports[12] procured by the load serving entities to meet their collective RA obligations. The middle bar represents an increase in the RA import level to 8,500 MW, the highest amount procured for the month of September over the last 6 years. The bar on the right further increases the level of imports from the middle bar by assuming an additional 1,000 MW of non-RA economic imports during the peak period. As with the stochastic sensitivity results, *Figure 4* demonstrates the importance of imports above typical RA import levels for meeting 1-in-2 and higher peak demand conditions during late summer.

[11] https://www.google.com/url?client=internal-element-cse&cx=001779225245372747843:e2wnztai65q&q=https://www.cpuc.ca.gov/WorkArea/DownloadAsset.aspx%3Fid%3D6442466860&sa=U&ved=2ahUKEwjWzYWMgKfwAhXjFDQIHeV-AyAQFjAAegQIARAB&usg=AOvVaw0ZSlD_aBQW-I1GlJ_Zjqle

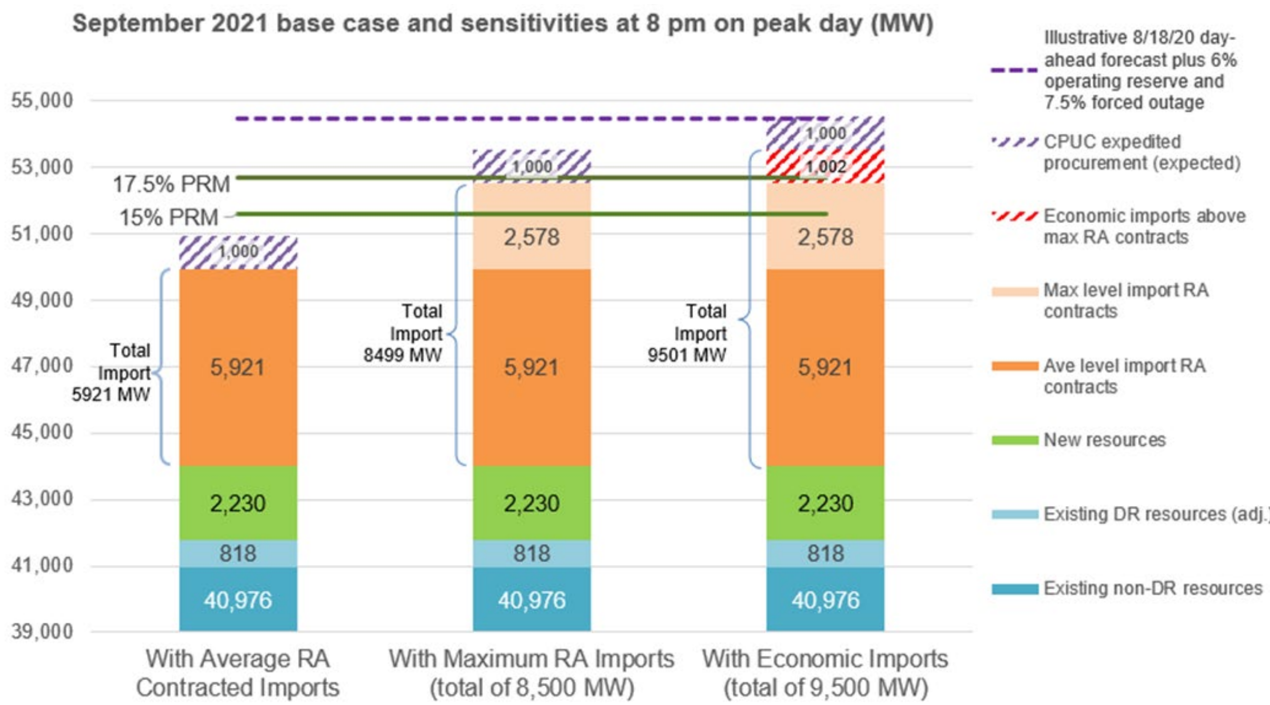
[12] The 2015 – 2020 average of the total import capacity procured by all load serving entities to meet their RA obligation is 5,921 MW.

- The bar on the left shows that if the system is limited to imports of 5,921 MW the 15 percent planning reserve margin (PRM) associated with 1-in-2 load cannot be met in September;
- The middle bar shows that if system imports reach 8,499 MW, approximately 2,600 MW greater than the typical RA procurement levels, 1-in-5 loads and the 17.5 percent PRM can be met;
- The bar on the right demonstrates that loads equivalent to the day-ahead forecast for August 18, 2020, the day of the ISO 2020 summer peak, would only be met if imports reach to a level of approximately 3,600 MW greater than the typical RA procurement levels and forced outages do not exceed the normal 7.5 percent rate;

Figure 4

ISO stack analysis for September 2021

(PRM levels based on CEC 1-in-2 load forecast plus planning reserve margin)



Status of the Aliso Canyon Gas Storage Operating Restrictions

Natural gas needs in Southern California are met by a combination of major gas pipelines, distribution gas infrastructure and gas storage facilities. Four major gas storage facilities are located in the Southern California Gas system, the largest of which is the Aliso Canyon facility located in Los Angeles County. Aliso Canyon and other gas storage facilities are used year-round to support the delivery of gas to core and non-core users. Among the non-core users are electric generators, which help meet electric demands throughout the region.

Aliso Canyon directly supplies 17 gas-fired power plants with a combined total 9,800 MW of electric generation in the Los Angeles basin and indirectly impacts 48 plants with a combined total 20,120 MW of electric generation across Southern California. There are limitations in attempting to shift power supply from resources affected by Aliso Canyon to resources that are not affected because of certain factors, such as local generation requirements, transmission constraints and other resource availability issues.

The ISO and the CPUC have taken separate but complementary actions to manage the ongoing situation. Between 2016 and 2019 the ISO put in place a number of operational tools and market mechanisms to enhance the ISO's and the impacted generator's ability to manage the issue.

On April 1, 2021, SoCalGas published its Summer 2021 Technical Assessment, which concluded that conditions remained about the same as last year and that SoCalGas will be able to meet the forecasted summer peak day demand, even without supply from Aliso Canyon.[13] In addition, SoCalGas has more flexibility to use Aliso Canyon to balance the system and ease energy price spikes pursuant to revisions made by the CPUC on July 23, 2019 under the Aliso Canyon Withdrawal Protocol to remove its classification as "an asset of last resort."[14]

Conclusions

The ISO anticipates supply conditions in 2021 to be better than 2020, but continues to see potential challenges in meeting demand during extreme heat waves affecting a substantial portion of the Western Interconnection causing simultaneously high loads across the West and reducing the availability of imports into the ISO balancing authority area. Improvements to supply conditions in 2021 are largely driven by the addition of new resources coming online as early as this summer. However, a second year of significantly lower than normal hydro conditions, virtually unchanged forecasted load levels under normal conditions, and increased possibility of extreme weather events indicate the ISO may still face challenges in meeting load this summer. Recent data from NOAA[15] confirms that conditions in the West are getting hotter and drier.

The results of a conservative net import sensitivity study shows that reduced levels of net imports during high-demand conditions significantly affects system reliability. Accordingly, this summer's Assessment indicates the ISO could face capacity shortfalls under the more extreme widespread, high load conditions that both drive up California loads and also restrict availability of imports from other systems due to the high demand across the West. These capacity shortfalls may be mitigated by additional extraordinary measures accessed under

[13] Southern California Gas Company, Summer 2021 Technical Assessment, April 1, 2021.

[14] Aliso Canyon Withdrawal Protocol: https://www.cpuc.ca.gov/uploadedFiles/CPUCWebsite/Content/News_Room/NewsUpdates/2019/UpdatedWithdrawalProtocol_2019-07-23%20-%20v2.pdf

[15] https://www.noaa.gov/news/new-us-climate-normals-are-here-what-do-they-tell-us-about-climate-change

extreme or emergency conditions to minimize the risk of actual firm load shedding. Since September 2020, the ISO has been working to enhance its operational procedures to prepare to operate reliably this summer, including the ability to access these extraordinary measures. The ISO will continue to find and act on opportunities as needed, but is guardedly optimistic given the measures already taken, including the greater coordination with the State and regional entities. Conservation during extreme events will continue to be critical to avoid shedding load. The ISO and the State entities have taken significant measures to inform consumers in a timely manner through the Flex Alert campaign to conserve energy when requested to avoid more serious and widespread outages.

This Assessment is a system level assessment and does not provide results on local area resource adequacy issues. In addition, this Assessment does not include potential risks associated with transmission facility forced outages, including transmission outages due to wildfires, which could hinder imports during critical supply conditions. Supply disruptions due to public safety power shutoff procedures are also not addressed in this report.

In monitoring the impact to peak demands due to COVID-19 during 2020, minimal to no load reductions to daily summer peak demand levels were observed during warmer weather. The ISO forecast models utilize the economic growth projections from Moody's, which contain their projections of the continuing economic impacts due to COVID-19. With the significant unknowns in how the COVID-19 pandemic will continue to impact society and how the various electric sectors use energy, no attempt was made to predict potential ongoing impacts to loads due to COVID-19 beyond the impact the forecast model attributes to changes in economic growth associated with the forecast from Moody's.

Preparation for Summer Operation

Preparing and publishing the Assessment report and sharing the results with industry participants and stakeholders is one of many activities the ISO undertakes each year to prepare for summer system operations. Given the widespread heat wave events of 2020 that led to firm load shedding in the ISO balancing authority area, the ISO, State entities, and others have taken a host of measures to improve system preparedness and performance in 2021. These include pursuing and approving procurement of additional resources, ensuring existing resources are retained in service, and improving operational readiness and measures to access resources or load reductions that can be implemented in when faced with the risk of shortfalls. Those reforms, modifications and other actions were discussed publicly most recently at a California Energy Commission workshop on summer 2021 reliability[16] held on May 4, 2021.

Other activities include coordinating meetings on summer preparedness with the WECC, California Department of Forestry and Fire Protection (Cal Fire), natural gas providers,

[16] CEC Integrated Energy Policy Report Joint Agency Workshop on Summer 2021 Reliability - Reliability Outlook, May 4, 2021, available at: https://www.energy.ca.gov/event/meeting/2021-05/session-1-iepr-joint-agency-workshop-summer-2021-reliability-reliability

Transmission Operators and neighboring balancing areas. For 2021, the ISO engaged these entities in a tabletop exercise where participants walked through scenarios that started seven days out from a peak load day and proceeded through to the potential need for shedding load in real time. The exercise practiced using the ISO Alerts, Warnings and Emergencies procedures, communications protocols, recent policy changes, and contingency reserve management procedures. The ISO's ongoing coordination with these entities helps ensure that everyone is prepared for the upcoming summer operational season.

Should the ISO system operating conditions go into the emergency stages—such as operating reserve shortfalls where non-spinning reserve requirements cannot be maintained or spinning reserves are depleted and operating reserves fall below the minimum requirement—the ISO will implement the following mitigation operating plan to limit loss of load in its balancing authority area:

- Activation of the Summer 2021 Joint Readiness Plan (ISO, CPUC, & CEC). This triggers communication 4-7 days in advance of an anticipated tight supply day or days to California water agencies, Utility Distribution Company (UDC) & Metered Subsystem (MSS), neighboring BAs;
- Utilization of the Flex Alert program, signaling that the ISO expects high peak load conditions. This program has proven to reduce peak load in the ISO balancing authority Area;
- Utilization of the ISO Restricted Maintenance program, which is intended to reduce potential forced outages during the high peak load conditions;
- Manual post-day-ahead unit commitment and exceptional dispatch of resources under Resource Adequacy contract to ensure ability to serve load and meet flexible ramping capability requirements;
- Manual exceptional dispatch of intertie resources that have Resource Adequacy obligation to serve ISO load;
- Utilization of Alert/Warning/Emergency program;
- Activation of the CPUC pilot Emergency Load Reduction Program (ELRP) upon declaration of an ISO Alert in the day-ahead timeframe;
- Utilization of Demand Response program including the Reliability Demand Response Resources (RDRR) under the “Warning” stage;
- Manual exceptional dispatch and utilization of backstop Capacity Procurement Mechanism for physically available resources that have un-contracted RA capacity;
- Coordinate with the ISO UDC/MSS to use firm load that can be dropped within 10 minutes of notification as contingency reserves. The market procured contingency reserves will then be dispatched to serve firm load;
- Assess curtailment of export or wheel schedules when preparing for firm load shed.

III. APPENDIX A: TECHNICAL REVIEW AND ASSESSMENT

This section consists of a more comprehensive review of input parameters and modeling approach and a subsequent discussion of the Assessment results.

Summer 2020 REVIEW

Weather

Figure 5 shows one of the weather parameters the ISO uses in its models for ranking weather (70 percent of the 631[17] maximum heat index plus 30 percent of the minimum temperature). Based on this parameter, 2020 ranks slightly lower than the 2006 extreme weather event. The weather database the ISO uses for its summer assessment load forecasting and weather normalization models consists of 26 years of historical data from 24 weather stations across the ISO, beginning in 1995 – the first year all 24 weather stations reported relative humidity data. Relative humidity data is used to calculate heat index, a significant input for the load forecasting models. The 26 year historical data set also represents a period of higher historical temperatures that more effectively reflects the impacts of climate change than longer term historical weather data sets.

Figure 5

Historical Annual Maximum Heat Index and Temperatures

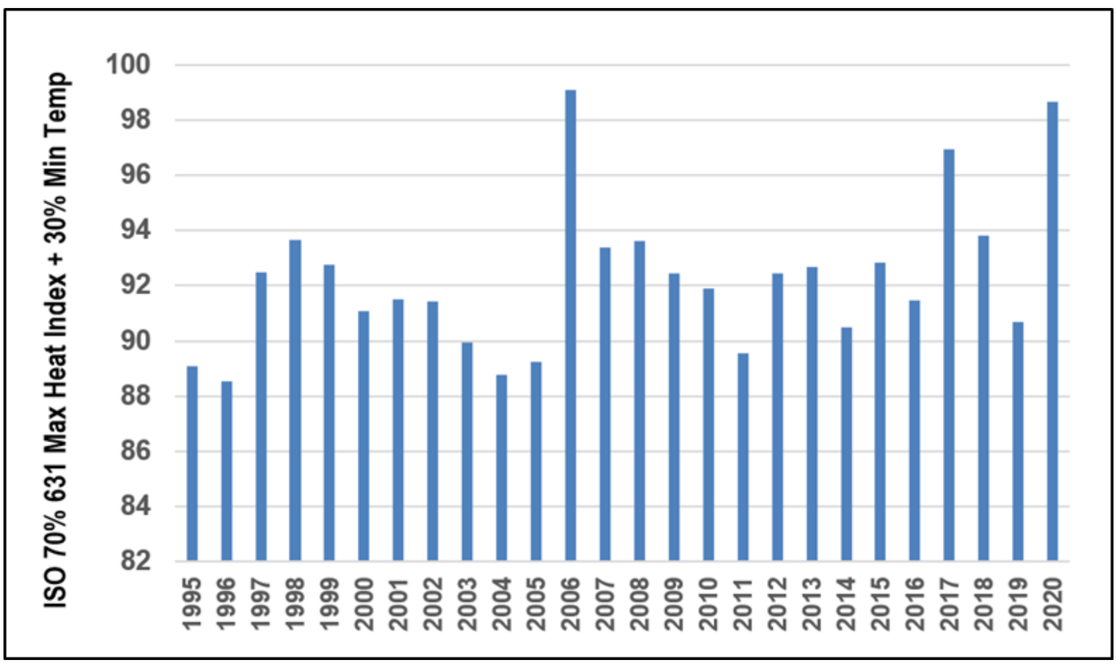


Figure 5 shows the ISO annual maximum weather parameter of 70 percent 631 Max Heat Index plus 30 percent Min Temp.

[17] 631 three-day temperature weighting index.

Demand

Figure 6 shows actual monthly peak demands from 2010 to 2020 for the ISO, SP26 and NP26. The fluctuation of the annual peak demand is primarily due to weather conditions unique to each year and changing economic conditions and demographics. The ISO peak demand has been significantly offset by the behind-the-meter solar installations during solar production hours, shifting the system peak hour to later in the evening when behind the meter solar production and grid-connected solar energy production is low or zero. To a lesser extent, increasing energy efficiency and the use of demand side management impacted peak demand as well.

Figure 6

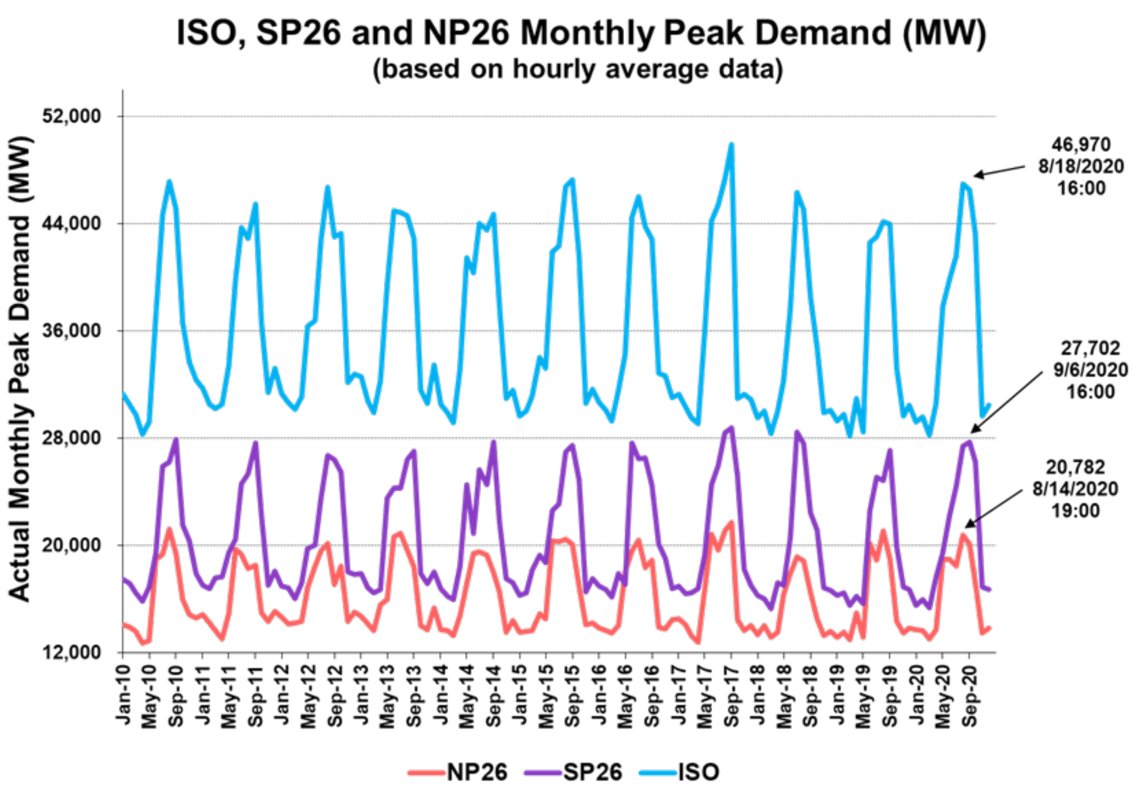


Figure 6 shows the ISO system peak and peaks for Northern and Southern California (2010-2020).

The recorded 2020 summer hourly average peak demand reached 46,970 MW[18] on 8/18/2020 at 16:00. Under a 1-in-2 weather condition, the 2020 weather normalized peak load is 45,742 MW. The 2020 annual peak demand for the Southern California zone (South of Path 26 or SP26) reached 27,702 MW and for the Northern California zone (North of Path 26 or NP26), the annual peak demand was 20,782 MW. The annual peaks for the ISO occurred on 8/18/2020 at hour ending 16:00, the annual peak for Southern California zone

[18] All demand data represented in this report is hourly average demand.

occurred on 9/6/2020 at hour ending 16:00, and NP26 occurred on 8/14/2020 at hour ending 19:00.

Load impacts due to COVID-19 were monitored from the beginning of the California stay at home orders through July 2020[19]. While reduction in energy consumption was observed, minimal to no load reductions to daily peak demand levels was observed during the month of July when compared to pre-COVID-19 conditions.

Table 5 shows the 2020 actual peak demands by area, estimates of reductions in the peak due to demand response, voluntary load reductions, various forms of load management, and load curtailments, and an assessment of the 2020 weather ranking at the time of the various area peaks. The load reduction estimates were developed using the forecast models utilized by the ISO Short Term Forecasting group to perform backcast estimates of the counterfactual loads that would have occurred had no interventions taken place. Weather conditions in the ISO BA area were extremely hot, ranked as a 1-in-9.3 weather event. The weather at the time of the actual NP26 peak demand was a 1-in-5 weather event, and the weather at the time of the SP26 peak demand was a 1-in-5.5 weather event. The weather rankings shown in *Table 5* will differ from the weather rankings performed using longer term weather data sets than the 26 year historical data set used here.

Table 5

2020 Summer Peak Load and Peak Day Weather Ranking Across the ISO

ISO Load Area	Date & Time	Actual Peak (MW)	Backcast Peak Reduction (MW)	Actual Peak plus Backcast Peak Reduction (MW)	Area Weather Index (deg. F)	Percentile	Weather Event
NP26	8/14/20 19:00	20,782	854	21,636	101.2	80%	1-in-5
SP26	9/6/20 16:00	27,702	882	28,584	97.7	82%	1-in-5.5
ISO	8/18/20 16:00	46,970	2,618	49,588	95.7	89%	1-in-9.3

Table 6 shows the 2020 actual peaks, 2020 backcast peak reductions, 2020 weather normalized peaks, and the 2020 1-in-2 peak demand forecasts. The 2020 heat wave resulted in the ISO actual peak demand plus peak reduction being 8.4 percent higher than the normalized peak demand of 45,742 MW. The Northern California actual peak demand plus peak reduction was 4.8 percent higher than the normalized peak demand forecast for NP26. The actual peak demand plus peak reduction in Southern California was 6.9 percent higher than the normalized peak demand for SP26.

[19] http://www.caiso.com/Documents/COVID-19-Impacts-ISOLoadForecast-Presentation.pdf#search=covid%2019%20impacts

Table 6

2020 ISO actual, normalized and forecast peak (MW)

2020 ISO Actual, Weather Normalized and Forecast Peak								
Zone	Actual	Backcast Peak Reduction	Actual + Peak Reduction	Normalized	1-in-2 Forecast	Actual + Peak Reduction	Forecast vs. Normalized	Time
NP26	20,782	854	21,636	20,649	20,245	4.8%	-2.0%	8/14/20 19:00
SP26	27,702	882	28,584	26,745	27,820	6.9%	4.0%	9/6/20 16:00
ISO	46,970	2,614	49,584	45,742	45,907	8.4%	0.4%	8/18/20 16:00

Supply

Actual daily supply and demand from June through September 2020 for the ISO system, the SP26, and NP26 zones are shown in *Appendix A: 2020 Summer Supply and Demand Summary Graphs.*

Interchange

Figure 7 shows the 2020 ISO daily peak demand and the net imports in the summer period. The net imports provided in *Figure 7* are limited to those days when the ISO daily system peak was 90 percent or more than the 2020 summer peak. There are numerous factors that determine the level of interchange between the ISO and other balancing authorities at any given time. These factors include market dynamics, the availability of generation internal and external to the ISO, resource adequacy contracting, transmission congestion, hydro conditions, forecasted renewable generation, demands within various areas, and day-ahead forecasts accuracy. On any given day, the degree to which any one of these interrelated factors influence import levels can vary greatly. Actual daily net import from June through September 2020 for the ISO system and the SP26 and NP26 zones are shown in *Appendix B: 2020 Summer Imports Summary Graphs.*

Figure 7

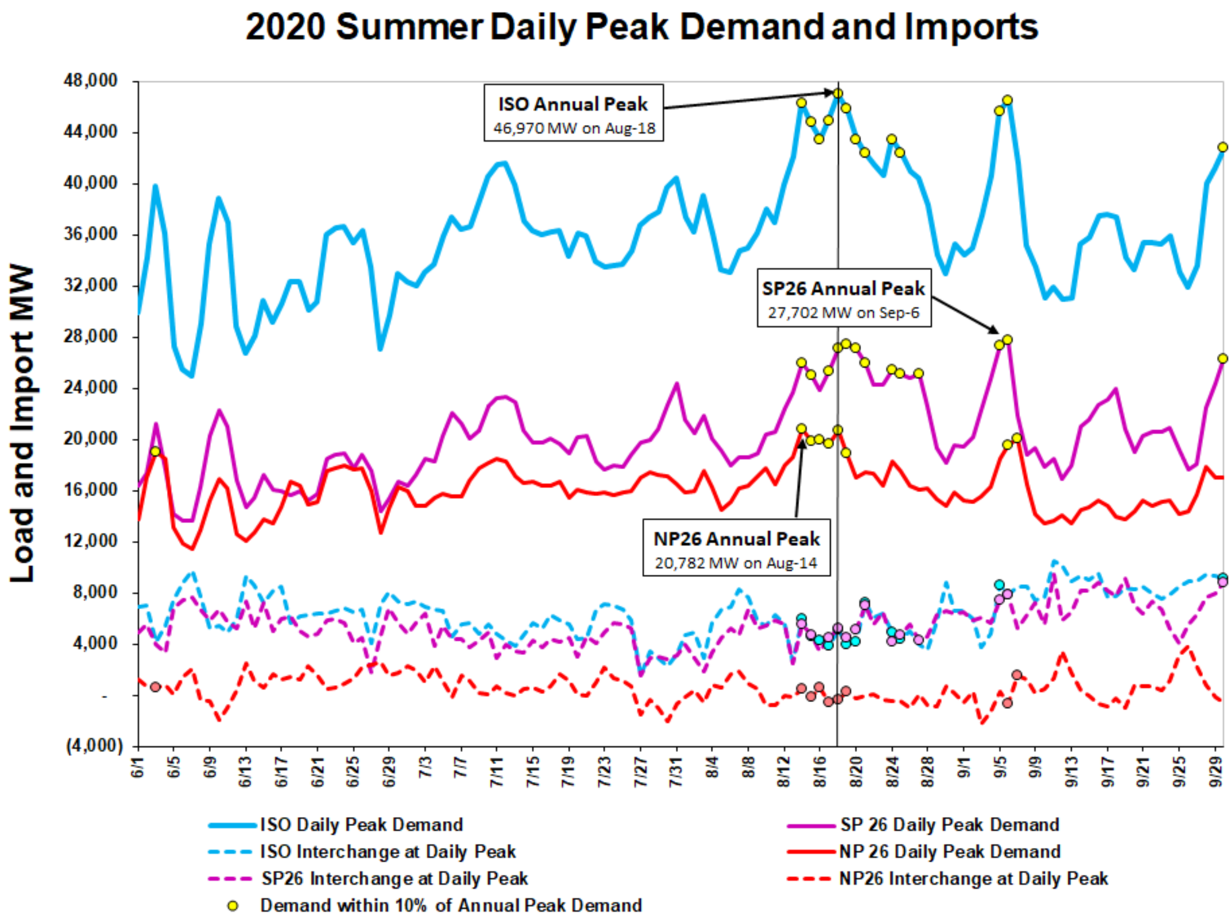


Figure 7 shows the amount of net imports at ISO 2020 daily system peaks.

Summer 2021 Assessment

ISO Loads

Annual Peak and Energy Forecast

The ISO's annual peak and energy forecast process has five steps. The first step is to develop daily peak and energy models for NP26 (Pacific Gas and Electric), and SP26 (Southern California Edison, San Diego Gas and Electric, and Valley Electric Association),[20] and the ISO using MetrixND®. The inputs are weather data, economic and demographic data, and historical loads (adding demand response back in and excluding water delivery pumping loads). The second step employs a weather simulation program to generate 182 weather scenarios using 26 years of historical weather data from 1995 through 2020. Seven

[20] The electric utility loads referenced within NP26 and SP26 are at the Transmission Access Charge area level.

different weather scenarios are developed for each historical year to simulate calendar effects across the weekdays. The third step uses a peak and energy simulation process to generate 182 annual peak and energy amounts through the MetrixND® models based on the 182 weather scenarios. The fourth step randomly generates 5,000 samples from each area's range of 182 annual peak and energy amounts. Finally, a range of typical pump loads during summer peak conditions are added back into the loads to arrive at 5,000 annual peak loads. The 1-in-2 peak load is calculated at the 50th percentile of the 5,000 annual peak loads, the 1-in-5 peak load is calculated at the 80th percentile and the 1-in-10 peak load is calculated at the 90th percentile.

The weather data comes from 24 weather stations located throughout large population centers within the ISO balancing authority. Weather data used in the model include maximum, minimum and average temperatures, cooling degree days, heat index, relative humidity, solar radiation indices, as well as various temperature weighting indices.

The historical loads are hourly average demand values sourced from the ISO energy management system (EMS). Water delivery pump loads were not included in the historical demand as they do not react to weather conditions in a similar fashion and are subject to interruption. Pump loads are added back into the forecast demand based on a range of typical pump loads during summer peak conditions.

It is important to note that the ISO experienced a west-wide extreme heat wave in August and again in early September of 2020. This heat wave caused electricity demand to exceed supply, resulting in two rotating outages on August 14 and 15. During the extreme heat wave, many mitigation measures were implemented to reduce electricity demand. The implemented actions included demand response, flex alerts, energy savings from state buildings per the California State Governor's direction and ships docked that transitioned from onshore electric power to on-board self-generation. To reflect the demand reduction from the implemented measures, the ISO performed a backcast using the ISO day-ahead load forecasting models to obtain a more accurate estimate of the true unmanaged electricity demand from August 14 to 19. The backcast results were used in place of the typical reconstituted load results as inputs to MetrixND load forecast model to perform the 2021 load forecast.

The ISO uses gross domestic product and population developed by Moody's Analytics for the metropolitan statistical areas within the ISO as the economic and demographic indicators to the models. *Figure 8* shows a baseline economic scenario forecast developed by Moody's Analytics that represents how the economy could perform based on Moody's baseline assumptions. According to Moody's, the Covid-19 remains a significant headwind to the U.S. economy with the worst of the economic fallout from the virus likely over. Travel, tourism and trade will remain hindered and the economy will continue to encounter difficulty until effective vaccines are widely adopted. With a high degree of uncertainty, the Moody's baseline forecast anticipates that the U.S. population will effectively achieve herd immunity from the virus this summer. The real GDP will grow stronger in 2021 and softer in 2022 and unemployment is moving sideways because of government economic stimulus. The baseline forecast is the median scenario where there is a 50 percent probability that the economy will perform better and a 50 percent probability that the economy will perform worse.

The ISO forecast is based on the Moody's baseline gross domestic product forecast released in December 2020. The gross domestic product data reflect actual historical data through Dec 31, 2019 (January 2020 and later historical data are estimates of actual GDP). Consequently, this forecast is based on the most current data available at the time it was developed. *Figure 9* shows the ISO 1-in-2, 1-in-5, and 1-in-10 peak forecasts based on the base case economic scenarios from Moody's Analytics. In monitoring the impact to July 2020 peak demands due to COVID-19 minimal to no load reductions to daily peak demand levels were observed. With the significant unknowns in how the COVID-19 pandemic will continue to impact society and how the various electric sectors use energy, no attempt was made to predict potential ongoing impacts to loads due to COVID-19 through the 2021 summer period.

Figure 8

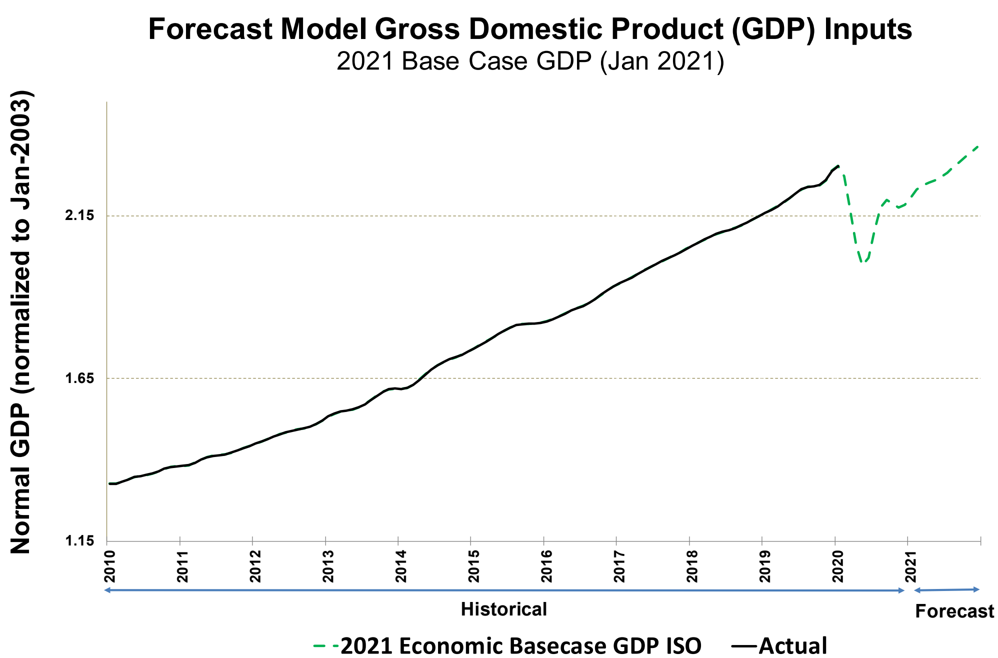


Figure 8 shows 2021 base case Gross Domestic Product for the metropolitan statistical areas within the ISO.

Figure 9

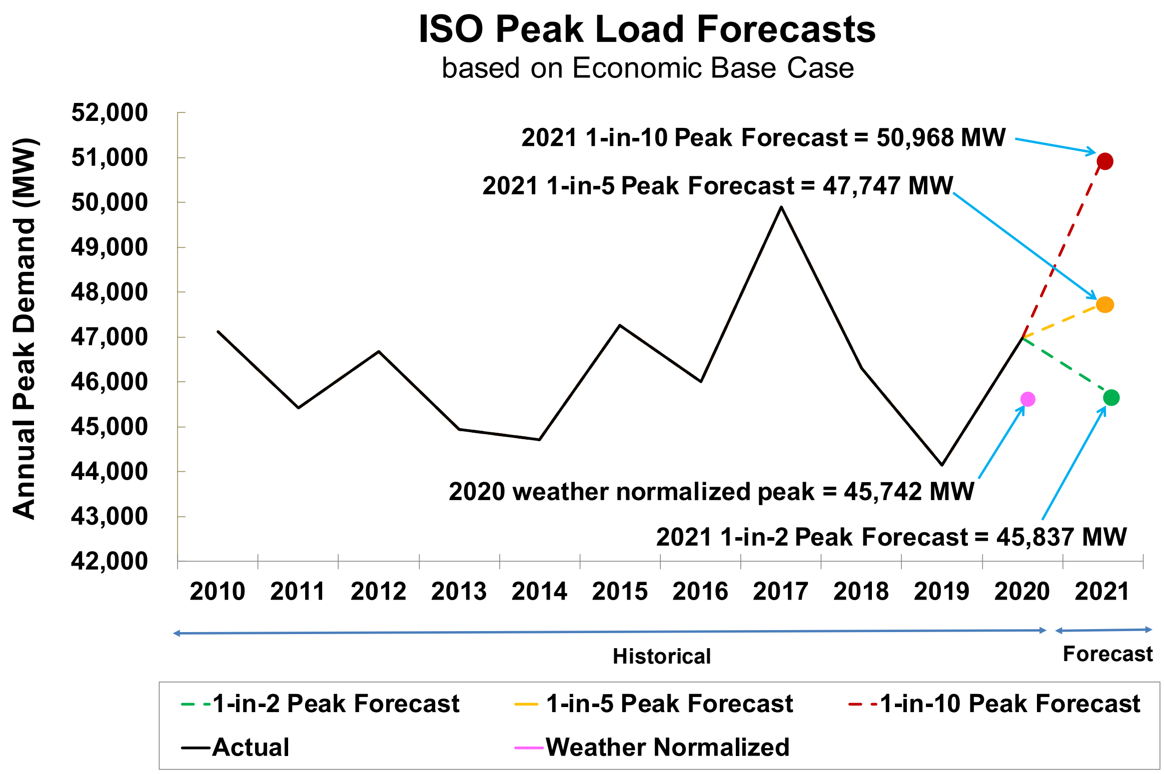


Figure 9 shows the ISO 2021 1-in-2, 1-in-5 and 1-in-10 peak forecasts.

The 2021 1-in-2 peak forecast of 45,837 MW[21] is only a 0.2 percent increase from the ISO 2020 weather normalized peak demand of 45,742 MW. The relatively unchanged demand projection is a result of Moody's Analytics baseline forecast, as shown in *Figure 8*, continuing load reductions from ongoing behind-the-meter solar installations, and energy efficiency program impacts on peak demand. The 1-in-2, 1-in-5 and 1-in-10 peak load forecasts for 2021 are shown in *Table 7.*

Table 7

2021 Peak Demand Forecast (MW)

2021	ISO	SP26	NP26
1-in-2	45,837	26,780	20,639
1-in-5	47,747	28,633	21,631
1-in-10	50,968	29,297	22,399

[21] The ISO developed 1-in-2 peak demand forecast of 45,837 MW is within 1 percent of the California Energy Commission's 1-in-2 Baseline Forecast Mid Demand Case of 45,784 from its 2021 Integrated Energy Policy Report.

A comparison of the 2021 peak demand forecast to the 2020 forecast is shown in *Table 8*. The 2021 1-in-2 and 1-in-5 forecasts are virtually unchanged from 2020. However, the higher loads associated with a 1-in-10 are attributable to including last year's extreme weather events in the historical weather database that is used to develop the range of load forecasts. This changed the high temperature end of the weather distribution profile so the probability of the historical extreme heat events is now within the range of a 1-in-10 weather event. The ISO 2021 1-in-10 peak demand forecast is 50,968 MW – 11 percent higher than the 1-in-2 forecast level, a significant increase from the 6 percent incrementally higher demand that the 2020 1-in-10 demand forecast was over the 1-in-2 forecast.

Table 8

2021 Peak Demand Forecast Compared to 2020

	1-in-2	1-in-5	1-in-10
CAISO 2020 Forecast	45,907	47,755	48,457
CAISO 2021 Forecast	45,837	47,747	50,968
Difference (MW)	-70	-8	2,511
Difference (%)	-0.2%	0.0%	5.2%

Net load is defined as hourly load minus grid-connected wind and solar production. In other words, net load is the remaining load that the ISO dispatches resources to serve after the gross load has been reduced by the amount of energy production from renewable resources. Renewable resources have an energy profile based on the availability of the resource they utilize to produce energy, such as solar and wind. The net load is served by the resources that the ISO is able to dispatch. *Table 9* shows the forecasted net peak load for 2021.

Table 9

2021 Net Peak Load Forecast (MW)

2021	CAISO Net Peak Load Forecast
1-in-2	40,093
1-in-5	43,488
1-in-10	44,541

Hydro Generation

California hydro conditions for 2021 are again below normal. The statewide snow water content for the California mountain regions peaked at 60 percent of average on March 31, 2021. California 2021 statewide snow water content is lower than 2020 when the statewide snow water content peaked at 63 percent of the average. On April 1, 2021, California's major reservoir storage levels were at 70 percent of average compared to 101 percent of average for 2020.

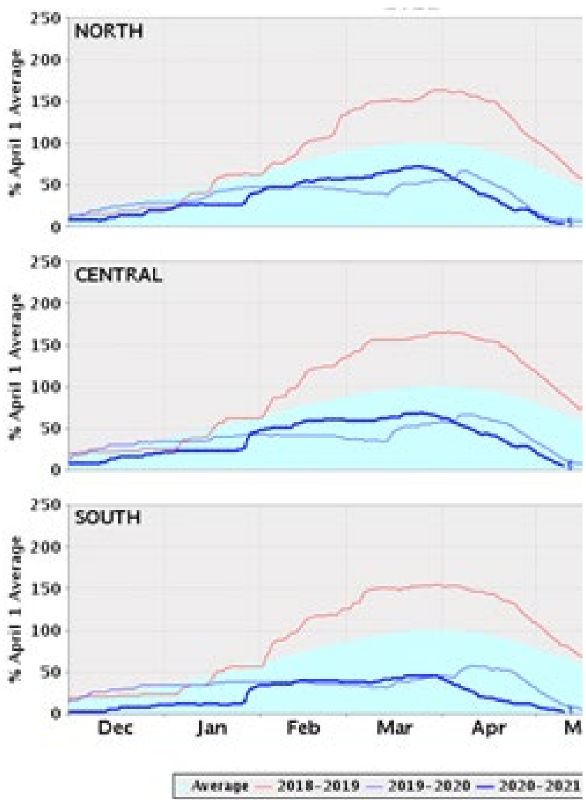
As of April 12, 2021, the Northwest River Forecast Center projected the April to September reservoir storage at The Dalles Dam on the Columbia River to be 89 percent of average, compared to 95 percent of average for 2020.

Hydro generation is modeled on an aggregated basis as two types: non-dispatchable run-of-river and dispatchable hydro generation. Run-of-river hydro generation has a fixed generation profile derived from historical data for the north and the south while the dispatchable hydro generation is optimized subject to the daily energy limits and daily maximum and minimum values. These are derived from historical data from years with similar snowpack and reservoir conditions. Dispatchable hydro generation can provide system capacity, ancillary service and flexible capacity. Pump storage generators are modeled individually and are optimized subject to storage capacity, inflow and target limits, and cycling efficiency.

Figure 10 is a chart of the daily snow water content for the last three years. The 2018-19 water year was well above normal, followed by the last two years of below normal snow water content. The three-year period for water years 2010-11, 2011-12 and 2012-13, shown in *Figure 11*, is the most similar historical period to 2021 and of the trend over the last three years. As a result, the 2013 hydro generation profile was used for the 2021 modeling process. *Figure 12* shows the similarity between 2012-13 and 2020-2021 snow water content years.

Figure 10

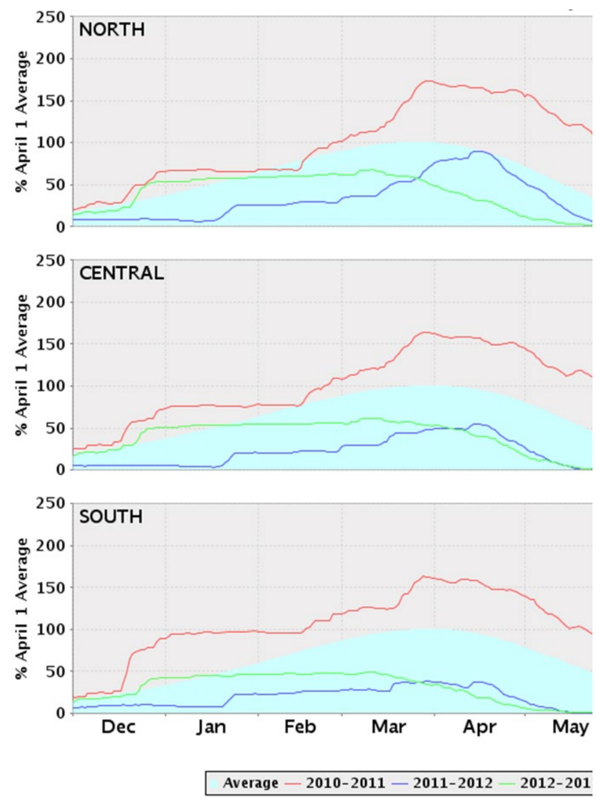
California Snow Water Content for Water Years 2018-19, 2019-20 & 2020-21



Source: California Department of Water Resources

Figure 11

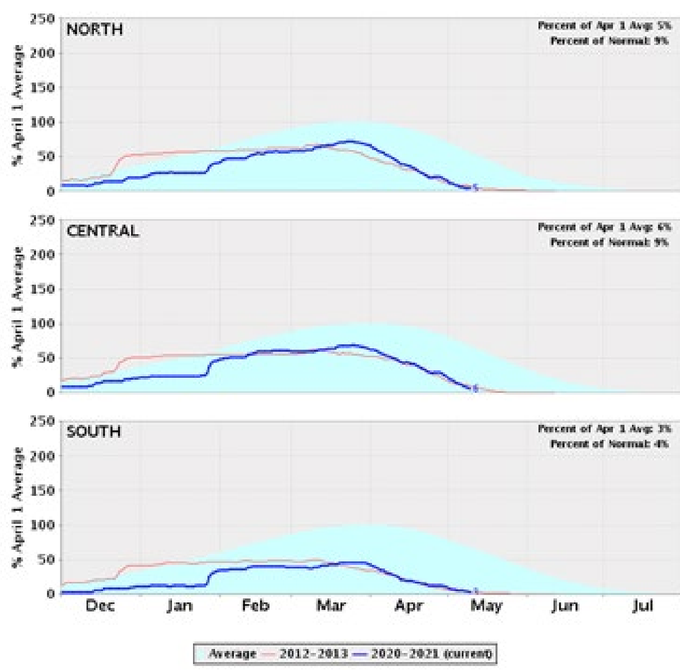
California Snow Water Content for Water Years 2010-11, 2011-12 & 2012-13



Source: California Department of Water Resources

Figure 12

California Snow Water Content for Water Years 2012-13 and 2020-21

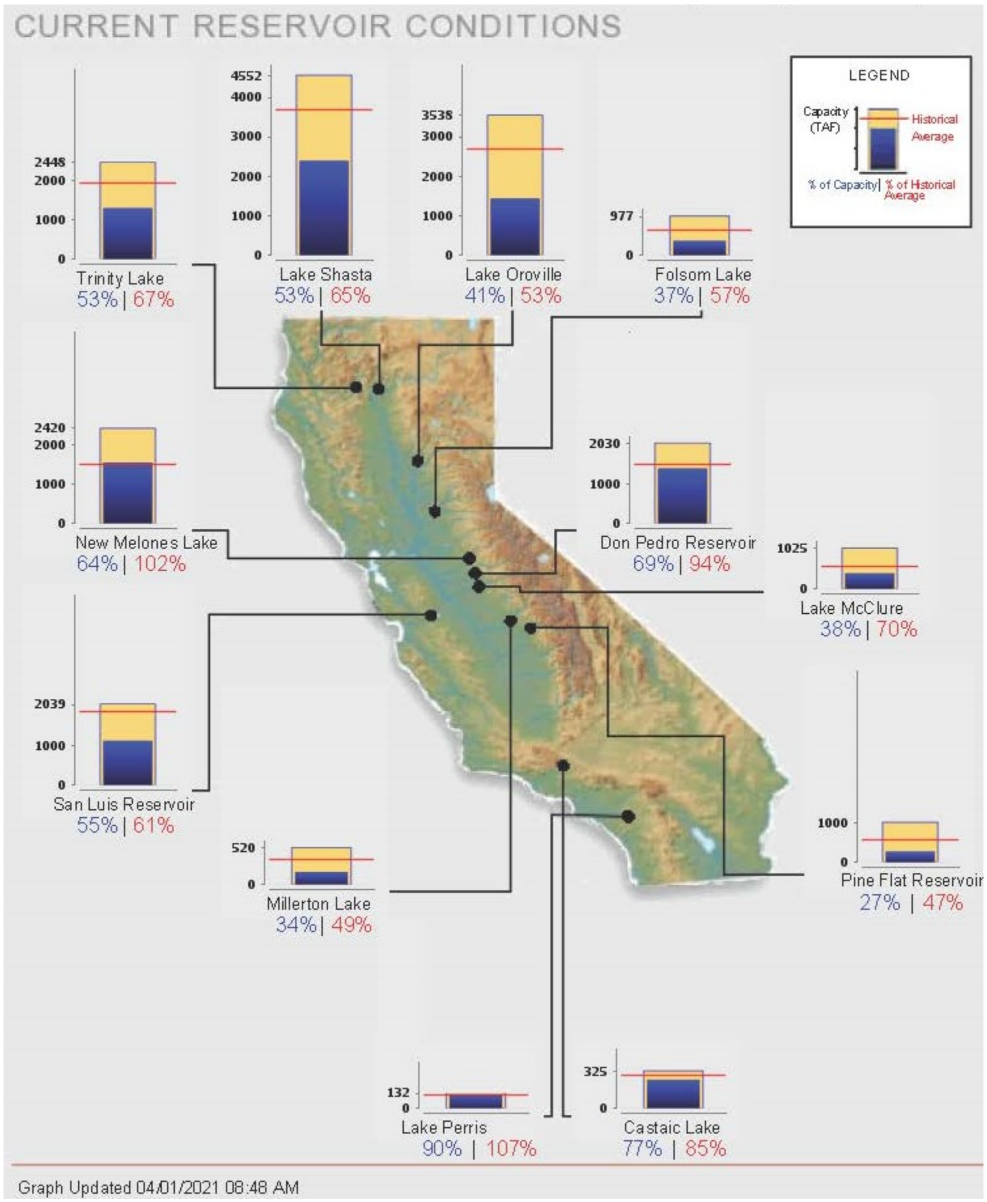


Source: California Department of Water Resources

Figure 13 shows the storage levels of the major reservoirs across the state, which are at 69 percent of historical average levels on a weighted average basis.

Figure 13

California Major Reservoir Storage Levels
70 percent of Historical Average Levels (weighted average)



Source: California Department of Water Resources

System Capacity

The ISO projects system capacity of 49,583 MW in June, 50,734 MW in July, 50,010 MW in August, and 47,385 MW in September for summer 2021. The decline of available capacity from July to September stems from the diminishing effective load-carrying capability of solar and wind generation in the calculation of NQC for wind and solar resources, and the waning of hydro generation from June through September. The final net qualifying capacity (NQC) list for compliance year 2021[22] and the ISO Master Control Area Generating Capability List[23], posted on the ISO website provide access to information the ISO used in developing the list of online resources that were modeled.

Each year, monthly qualifying capacity (QC) values are developed for generators eligible to participate in the CPUC's Resource Adequacy program. The ISO uses the QC values to develop the NQC for each eligible generator and publishes the NQC list. The NQC values for each resource describes the amount of generation that has been deemed deliverable and can be utilized to meet Resource Adequacy requirements. The NQC value for dispatchable resources depends on its demonstrated capacity and deliverability — the ability of the grid to deliver the generation to load centers. The ISO determines the NQC by testing and verifying as outlined in the ISO tariff and the applicable business practice manual. The NQC values for solar have been declining because the ISO system peak has shifted to later in the day when solar production is diminished to levels at or near zero.

The largest generation resource fuel type is natural gas, accounting for 57.4 percent of the ISO summer maximum on-peak available capacity; the second largest generation type is hydro, which accounts for 14.3 percent. Solar, based on effective load carrying capability, accounts for 10.6 percent. Nuclear generation is 4.5 percent, wind is 3.4, biofuel and geothermal make up 3.3 percent. Battery is 2.8 percent, demand response 2.3 percent and oil generation provides 0.2 percent. The overall resource percentages by fuel type is shown in a chart in *Appendix C: 2021 ISO Summer Maximum On-Peak Available Capacity by Fuel Type.*

System Capacity Additions

Table 10 shows the total new installed generation capacity of 3,961 MW[24] coming online from June 1, 2020 to September 1, 2021: 1,613 MW is dispatchable and 2,348 MW is non-dispatchable[25]. During the same period, 81 MW of generation capacity will retire or be mothballed: 43 MW is dispatchable and 38 MW is non-dispatchable. The net of additions

[22] Final Net Qualifying Capacity Report for Compliance Year 2020: http://www.caiso.com/planning/Pages/ReliabilityRequirements/Default.aspx

[23] Master Control Area Generating Capability List: http://www.caiso.com/planning/Pages/GeneratorInterconnection/Default.aspx (under Atlas Reference)

[24] New resource capacity was developed from the ISO Master File and the New Resource Implementation process to determine the anticipated commercial operation date of new resources expected to come online within the 2021 Assessment study period. The amounts were based on known information as of 3/24/2021. New resources from this process were cross checked against resources known by the CPUC to be sure all resource the CPUC is expecting were accounted for.

[25] Non-dispatchable resources are technologies that are dependent on a variable fuel source and are modeled in PLEXOS as energy production profiles based on historical generation patterns. Non-dispatchable technologies include biofuels, geothermal, wind, solar, run-of-river hydro, and non-dispatchable natural gas.

and retirements is an increase of 3,880 MW, with a net increase of dispatchable capacity of 1,570 MW.

Of the new resource capacity coming online, 1,493 MW is from battery energy storage systems (BESS) coming online by 9/1/2021. Thirty-eight percent of the total additions (1,493 MW) are BESS facilities. While not providing new energy generation, BESS enable surplus energy generated during periods of high solar production and energy generated during periods of lower energy prices to be stored and provided to meet system needs during the net peak period when solar production ramps down and is no longer available. BESS are able to provide system capacity, ancillary service and flexible capacity.

As with any new resource project in construction, there is a risk that some of the new resources listed in *Table 10* are not able to meet their target commercial operation date. While delays in a significant portion of the projects yet to achieve their commercial operation date are not anticipated, a delay in a significant amount of this capacity could impact the results of the Assessment.

Table 10

Generation Additions (MW)

From June 1, 2020 to September 1, 2021

Fuel Type	Additions by June 1, 2021*	Incremental Additions by July 1, 2021	Incremental Additions by Aug. 1, 2021	Incremental Additions by Sept. 1, 2021	Total Additions by Sept. 1, 2021
BESS	675	343	472	3	1,493
Bio Fuel	6	0	0	0	6
Natural Gas	152	0	0	0	152
Geothermal	11	0	0	0	11
Hydro	41	0	0	0	41
Solar	1,497	0	498	0	1,995
Wind	263	0	0	0	263
Total	2,645	343	970	3	3,961
Cumulative Total	2,645	2,987	3,957	3,961	
* Includes additions from June 1, 2020 to June 1, 2021.					

System Capacity Retirement and Unavailability

Forced outages are generated for individual units on a random basis by PLEXOS using each unit's historical forced outage rate with a uniform distribution function based on 2015 through 2017 individual historical summer forced outages. Planned outages are sourced from the ISO outage management system.

Table 11 shows the resources that have retired or mothballed since June 1, 2020. To date, there are no other known additional retirements that will take place by June 1, 2021. Of the

81 MW of generation that have retired since June 1, 2020, 43 MW are dispatchable and 38 MW are non-dispatchable.

Table 11

Recently Retired or Mothballed Generation (6/1/2020 to 6/1/2021)

RESOURCE ID	Current Status	MW	Actual offline Date	Fuel Type	PTO	Dispatchable
JAWBNE_2_SRWND	Mothballed	25	12/14/2020	WIND	SCE	N
ANAHM_7_CT	Retired	43	6/30/2020	GAS	SCE	Y
GARNET_2_DIFWD1	Retired	3	9/2/2020	WIND	SCE	N
PANSEA_1_PANARO	Retired	10	12/13/2020	WIND	SDGE	N
SBERDO_2_QF	Retired	0	6/30/2020	OTHR	SCE	N
MESAS_2_QF	Retired	0	7/23/2020	OTHR	SCE	N
Non-Dispatchable		38				
Dispatchable		43				
Total		81				

Unit Commitment

The PLEXOS production simulation applies unit commitment constraints for generator startups and shutdowns. While the generator is starting up, it cannot provide ancillary or load following services while ramping from initial synchronization to its minimum allowed operating capacity. Similarly, when a generator is in the process of shutting down, it cannot provide ancillary or load following services once it has ramped down passed its minimum capacity threshold. Once a generator is committed, it must remain in operation for its minimum run time before it can be shut down. After a generator has been shut down, it is not available for commitment again until it has been off for its specified minimum down time.

Once a generator is operating within its operating range (between its minimum and maximum capacity) it must meet the criteria set out below.

If a generator is ramping up:

- Regulation up, spinning, and non-spinning provided by a generator cannot exceed its 10-minute ramping up capability and unused capacity;
- Energy, regulation up, spinning, and non-spinning provided by a generator cannot exceed its 60-minute ramping capability and its available unused capacity.

During ramping down:

- The difference between a generator's minimum capacity and its current operating point determines the amount of regulation-down and load following-down that can be provided by a generator.

Therefore, the model sets 60 minutes ramping time for energy and 10 minutes for ancillary services in each hour's simulation.[26] Each dispatchable generator can run at its maximum ramp rate between its minimum and maximum capacity.

Curtailable Demand and Demand Response

Curtailable Demand includes demand response, pumping load, and aggregated participating load that can provide non-spinning reserve or demand reduction. Curtailable demand reduces end-user loads in response to high prices, financial incentives, environmental conditions or reliability issues. It can play an important role to offset the need for more generation and provide grid operators with additional flexibility in operating the system during periods of limited supply.

Demand response programs can be modeled as supply side resources that have triggering conditions in the stochastic simulation model. They include base interruptible programs, aggregator managed portfolios, capacity bidding programs, demand bidding programs, smart AC, summer discount plans, and demand response contracts.

Whenever the model depletes all available resources before meeting the load and ancillary service requirements the model will utilize demand response programs. The total amount of demand response resources modeled for 2021 is 1,218 MW.

The Flex Alert program is a voluntary energy conservation program that alerts and advises consumers about how and when to conserve energy. The Flex Alert program continues to be a vital tool for the ISO during periods of high peak demand or other stressed grid conditions to maintain system reliability. The alerts also serve as a signal that both non-event and event-based demand response are needed.

Interchange

The model simulates 35 WECC zones and 91 WECC interchange paths between zones, as shown in *Figure 14*. The zonal interchange path limits were set based on the WECC Path Rating Catalog. Transmission limits within the zones were not modeled and the model cannot provide results related to local capacity requirements. The transfer capabilities between any two adjacent zones reflect the maximum simultaneous transfer capabilities. In addition, a total ISO maximum net import limit was set based on historical net import patterns. Path 15 and Southern California Import Transmission (SCIT) nomogram constraint were enforced in the model.

[26] The maximum ancillary service (regulation or spinning) a generator can provide (the maximum ramp up rate × 10 minutes) is calculated by PLEXOS on an hourly basis.

Figure 14

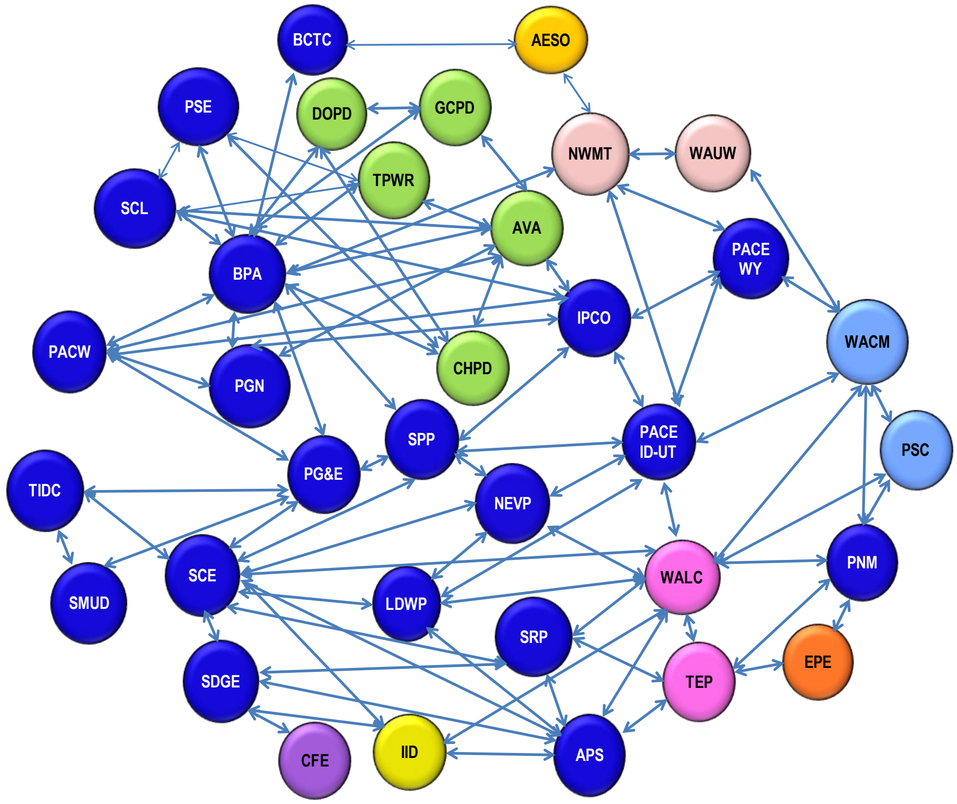


Figure 14: Simulation covers 35 WECC zones and 91 paths.

Net Import Constraints

Table 12 shows historical ISO net imports when the ISO load is equal to or greater than 43,000 MW during 2017 to 2020. The ISO system reliability depends on a certain range of net imports from neighboring balancing authorities, particularly during higher system peaks. This trend indicates that the availability of net imports at historical levels could be at risk at times when the ISO may be most dependent on such net imports.

Table 12

ISO net imports with ISO load equal to or greater than 43,000 MW during summer from 2018 to 2020

Year	2020	2019	2018
Min	2,521	4,743	2,898
First Quartile	4,043	6,046	4,166
Median	5,069	6,615	5,136
Third Quartile	7,063	7,434	6,602
Max	9,975	8,792	9,541

When seasonal high temperature increase electric energy consumption in California, neighboring BAs' electric energy consumption are often high as well. Under these conditions, imports from neighboring BAs will frequently be reduced when the ISO's demand ramps up to its peak. To reflect this system operation situation in the ISO's production simulation model, a net import nomogram was developed based on historical EMS net import data from 2018 to 2020. *Figure 15* shows the net imports during the hours of hour-ending 16 – 21 when demand is at or above 41,000 MW[27] for all summer months during 2018 – 2020. Analyses of the monthly trends of net imports demonstrate a declining nature of net imports as demand increases. *Figure 15* shows the on peak net import nomogram for the base case during the hours of hour-ending 16 – 21 to cap the level of net imports allowed by the model. During non-peak hours the net imports are capped at 10,905 MW, the highest net import experienced during all hours of 2020. The charts in Appendix B provide additional information on net imports at time of daily peak demand.

- Off peak net imports (HE 1 - 15, 22 - 24): capped at 10,905 MW (the maximum net imports during 2020)
- On peak nomograms (HE 16 - 21):
  - Base case nomogram: Net imports capped at 10,560 MW when the ISO peak is 41,000 MW, declining to 6,095 MW, the maximum of the monthly average amounts in *Table 13*, when the ISO peak is 50,956 MW, the 2021 1-in-10 forecast amount;
  - Sensitivity case nomogram: Net imports capped at the average RA net import from 2015 to 2020 in Table 13;

[27] 41,000 MW is 90 percent of the forecast of the ISO 2020 1-in-2 peak demand of 45,907 MW.

Figure 15

On-peak net import nomogram used in the base case

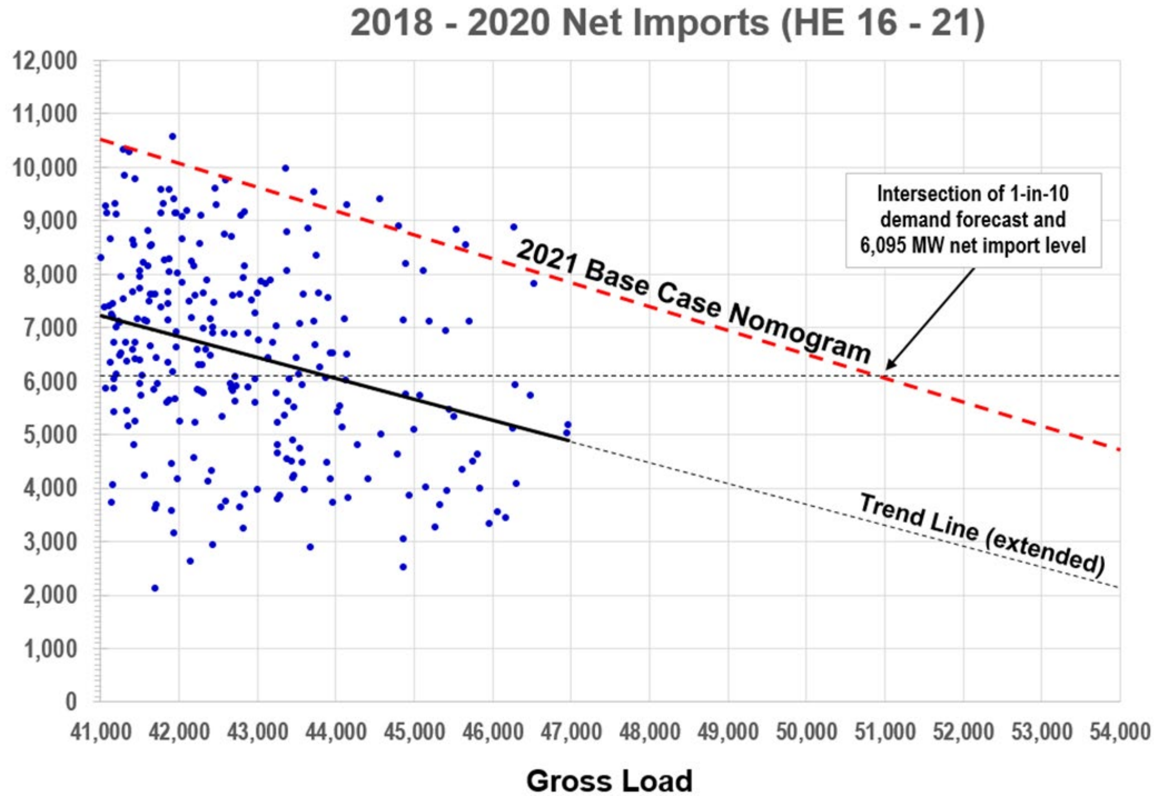


Figure 15 shows ISO net imports vs. ISO load during the hours of hour-ending 16 – 21 when the demand is at or above 41,000 MW for the years 2018 to 2020.

Table 13

Historical Resource Adequacy Summer Monthly Imports (2015 – 2020)

2015 - 2020 Summer RA Import Showings			
Month	Maximum	Minimum	Average
June	4,692	3,311	**3,922**
July	6,197	3,840	**5,340**
August	6,480	5,624	**6,095**
September	8,498	4,486	**5,921**

Stochastic Simulation Approach

To evaluate resource adequacy and to understand how the system will respond under a broad range of operating conditions, the modeling methodology uses all active market participant capacities available within the ISO balancing authority regardless of contractual arrangements. While some resources may not receive contracts under the Resource Adequacy program, and may possibly contract with entities outside the ISO for scheduled short-term exports, these resources are still considered available to the ISO for the purposes of this Assessment. Resources not procured for the Resource Adequacy program do not have must-offer obligation to the ISO Day Ahead and Real Time Market. The ISO may be able to utilize these non-RA resources, if physically available, via the backstop Capacity Procurement Mechanism.

Conventional generation units such as gas and nuclear are modeled as individual dispatchable units, while non-dispatchable resources, such as qualifying facilities (QFs), biofuel, geothermal, solar and wind, are modeled using fixed hourly generation profiles based on aggregated historical hourly generation profiles, which are adjusted based on the projected capacity additions and retirements.

In recent years, significant amounts of new renewable generation, especially solar, have reached commercial operation to meet the 60 percent requirement by 2030. To successfully meet the state's Renewables Portfolio Standard goals, increasing amounts of flexible and fast responding resources must be available to integrate the growing amounts of variable resources. These increasing amounts of variable resources integrated with the ISO grid pose unique challenges for ISO operations and for the analytical tools used by the ISO to assess near-term reliability.

As new renewable resources come on the system, the ISO reliability focus has evolved from meeting the gross peak demand to meeting both net peak demand and flexible capacity requirements. The gross peak usually occurs at the hour ending 16:00 to 18:00 while net peak occurs in the hour ending 19:00 to 21:00 timeframe, when solar generation is close to zero. The ISO's evolving net load profile – gross load minus grid-interconnected solar and wind generation – has become known as the duck curve. The growing amount of photovoltaic solar generation that is interconnected to the ISO grid continues to change the ISO's net load profile and creates more challenges and uncertainty for ISO operations.

Photovoltaic solar generation located behind the customer meter is an additional impact, affecting the gross load and further decreasing the net load that the ISO serves. The result is a constantly increasing ramping requirement, significantly more than what has been required from the generation fleet in the past, both upward and downward. Furthermore, solar generation does not provide significant power at the hours ending 19:00 to 21:00, which leads to reliance on gas and other non-solar generation after sunset. The continuing decline in dispatchable generation in the ISO as dispatchable units retire is beginning to challenge the ISO system's ability to meet net peak demand after sunset and flexible capacity requirements.

To assess the changing resource needs from the increasing number of variable resources and declining fleet of dispatchable resources, the ISO started to use the PLEXOS stochastic model in the development of the 2016 Summer Assessment. To mimic the real-time market short-term unit commitment function during the window extending 4.5 hours prior to real-time and the real-time unit dispatch function 1 hour 45 minutes prior to real-time for the intra-hour requirement to cover intra-hour uncertainty and variability, the ISO calculates the intra-hour regulation and load following requirements and converts these intra-hour requirements to hourly requirements using a probabilistic Monte Carlo simulation program developed by Pacific Northwest National Laboratory, inputting them as system requirements in the PLEXOS stochastic model.

The model simulates 35 WECC zones with 91 WECC interchange paths. It uses a mixed-integer linear programing to determine the optimal generation dispatch. The model runs chronologically to dispatch capacity, ancillary services and load following to seek the least cost, co-optimized solution to meet system demand and flexibility requirements simultaneously. Operational constraints include forced and planned outage rates, unit commitment parameters, minimum unit up and down times, unit heat rates, and ramp rates for each generator in the ISO.

The model runs 2,000 scenarios on an hourly interval chronologically. Each scenario has a 2,928-hour profile from June 1 to September 30[28]. The optimization time horizon was set as 24 hours. The end status of one optimization is used as the initial status of the next optimization. For hours when supply is sufficient, the model calculates the Unloaded Capacity Margin (UCM) and determines the Minimum Unloaded Capacity Margin (MUCM) for each 2,928-hour profile scenario based on load and available resources including curtailable demand, imports, and exports. Each of the 2,000 scenarios produce one MUCM value over the 2,928 hours from June 1 through September 30. If supply is not sufficient, the model reports the unserved hours and unserved energy where demand exceeds supply.

UCM (t) = $\frac{Unloaded\ Capacity(t)}{Load(t)}$[29]

MUCM = Min $(UCM\ (1), \ldots, UCM\ (t), \ldots, UCM(2{,}928))$

Where, *Unloaded Capacity (t)* is any portion of online generation capacity not serving load and offline generation capacity that can come online in 20 minutes or less to serve load as well as curtailable demands such as demand response, interruptible pumping load, and aggregated participating load that can provide non-spinning reserve or demand reduction.

The 2,000 unique scenarios are randomly generated, each representing a combination of forecasted 2,928 hourly load profiles and renewable generation levels based on historic annual weather patterns, using a two-step process. The first step is to build three pools of load, wind and solar profiles. In this step, 26 years of historical daily weather profiles were used to forecast 182 daily and annual peak profiles and annual energy loads, which are

[28] The study period of June 1 through September 30 in each scenario represents 2,928 hours (24 hours ✖ 122 days).

[29] Gross or total ISO load as opposed to net load or consumption which includes load served by behind the meter resources.

adjusted to actual historical hourly load profiles to create 182 hourly load profiles. These 182 hourly load profiles were combined with 12 hourly wind and 7 hourly solar profiles to generate 15,288 scenarios[30], among which 2,000 scenarios were randomly selected for the stochastic modeling process, illustrated in *Figure 16*.

Figure 16

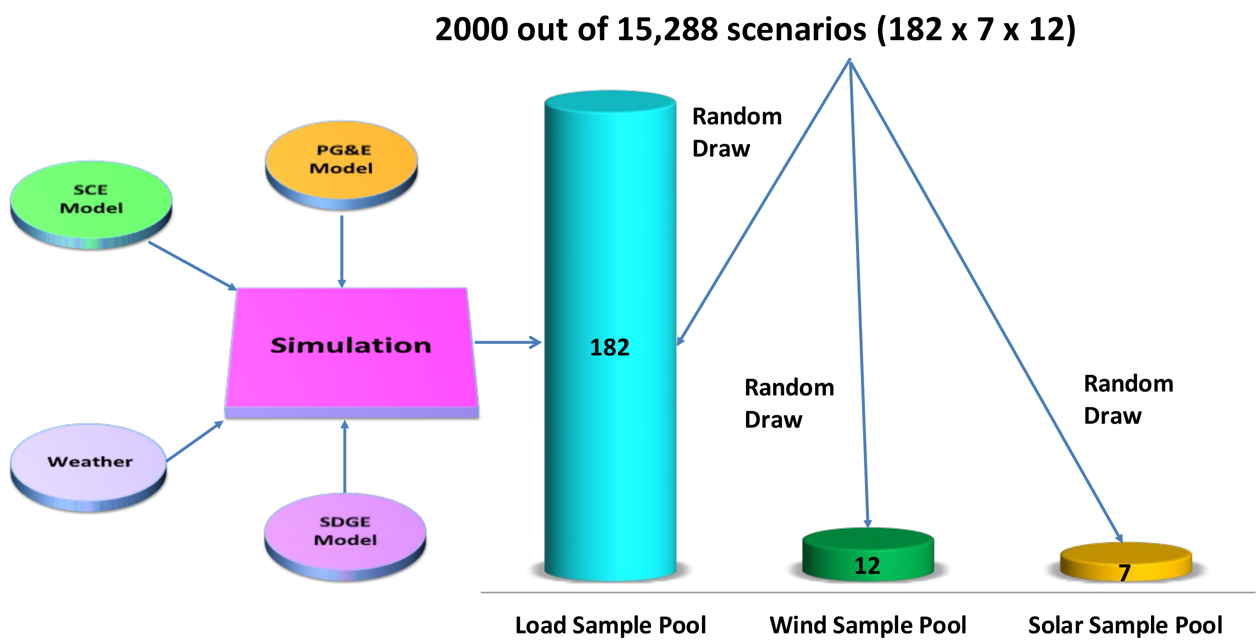


Figure 16: 2,000 scenarios of load, wind and solar are randomly selected from 11,550 scenarios.

Stochastic Simulation Results

The Assessment performed base case and sensitivity case studies to assess resource adequacy based on historical net import levels and under a more conservative net import assumption. The simulation results include the system capacity adequacy, ancillary service and flexible capacity adequacy.

Base Case Study

System Capacity Adequacy

The model produces an UCM for each hour modeled. Taking into account the unloaded capacity margin for all of 2,928 hours within each of the 2,000 summer scenarios, the UCM ranges from a high of 95 percent, down to a low of zero, with a very small number of scenarios at both extremes. The median value of all unloaded capacity margin values is 37.8 percent in *Figure 17*.

[30] 182 load profiles × 7 solar profiles × 12 wind profiles equals 15,288 scenarios.

Figure 17

ISO Unloaded Capacity Margins for base case June through September 2021

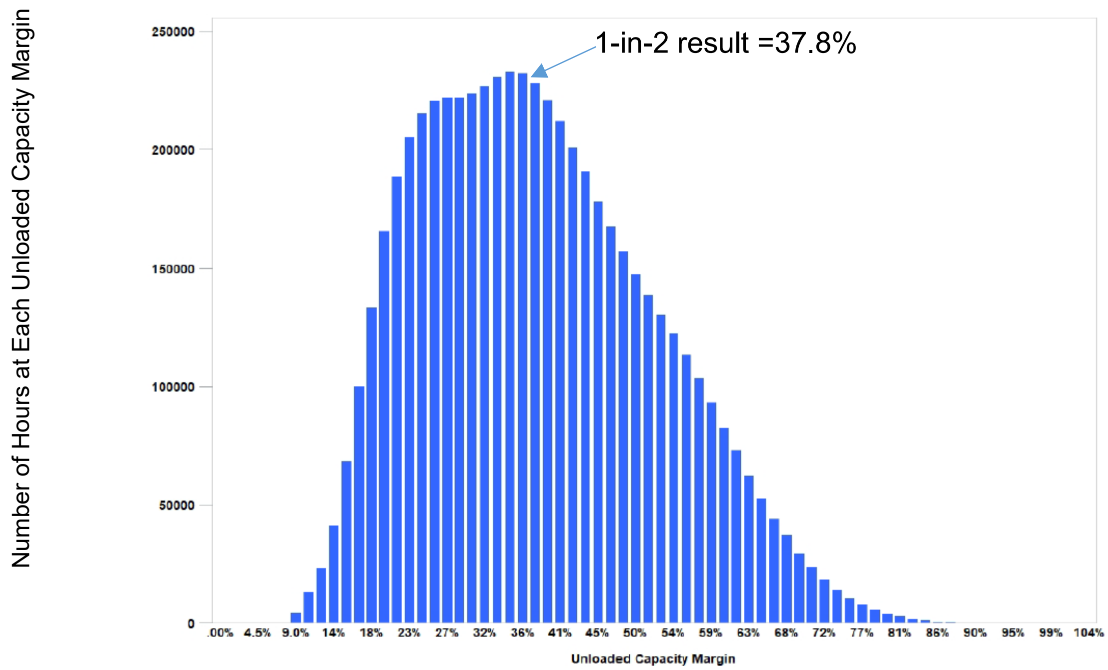


Figure 17 shows the distribution of the UCMs over all 2,928 summer operating hours from all 2,000 scenarios.

The ISO has developed a series of emergency stages[31] to communicate periods of low operating reserve conditions. A stage 1 emergency is usually issued when the ISO anticipates or forecasts the system will not be able to maintain the required contingency reserve level, and there are insufficient additional resources (in or out of market) to maintain or recover the contingency reserves required. The ISO will usually issue a stage 1 emergency when the operating reserve is seesawing above, then below the contingency reserve requirement and load continues to increase or energy supplies continues to decline. A stage 2 is an indication that all the steps available under a stage 1 do not resolve or recover the reserve deficiency and the system is using non-spin reserves to meet load and spin requirements, thereby making non-spin and contingency reserves deficient. A stage 3 is an indication the system cannot maintain the spinning reserve requirement, generally 3 percent of load, and firm load interruption is imminent or in progress.

Table 14 and Figure 18 show base case results where the ISO system has 6.4 percent probability of operating at stage 2, based on 128 scenarios that produced at least one hour of potential stage 2 emergency conditions, 4.8 percent probability at stage 3, based on 96 scenarios that produced an hour or more of potential stage 3 emergency conditions, and 4.6 percent probability of unserved energy with 91 scenarios showing unserved energy.

[31] See System Alerts, Warnings and Emergencies Fact Sheet on the ISO webpage: http://www.caiso.com/informed/Pages/Notifications/NoticeLog.aspx

Demand response programs would have been utilized if needed to maintain a 6 percent operating reserve margin and would be fully utilized in cases where the operating reserve margin is below 6 percent. Under this severe operating condition, the ISO will issue a notice of potential load interruptions to utilities – whether actual interruptions would occur depends on the specific circumstances and potential for recovering reserves.

Table 14

Probability of system capacity shortfall for base case

System Capacity Shortfall	Shortfall Probability	Number of Shortfall Case
Stage 2	6.4%	128
Stage 3	4.8%	96
Unserved energy	4.6%	91

Figure 18

Scenarios with stage 2, stage 3 and unserved energy for base Case

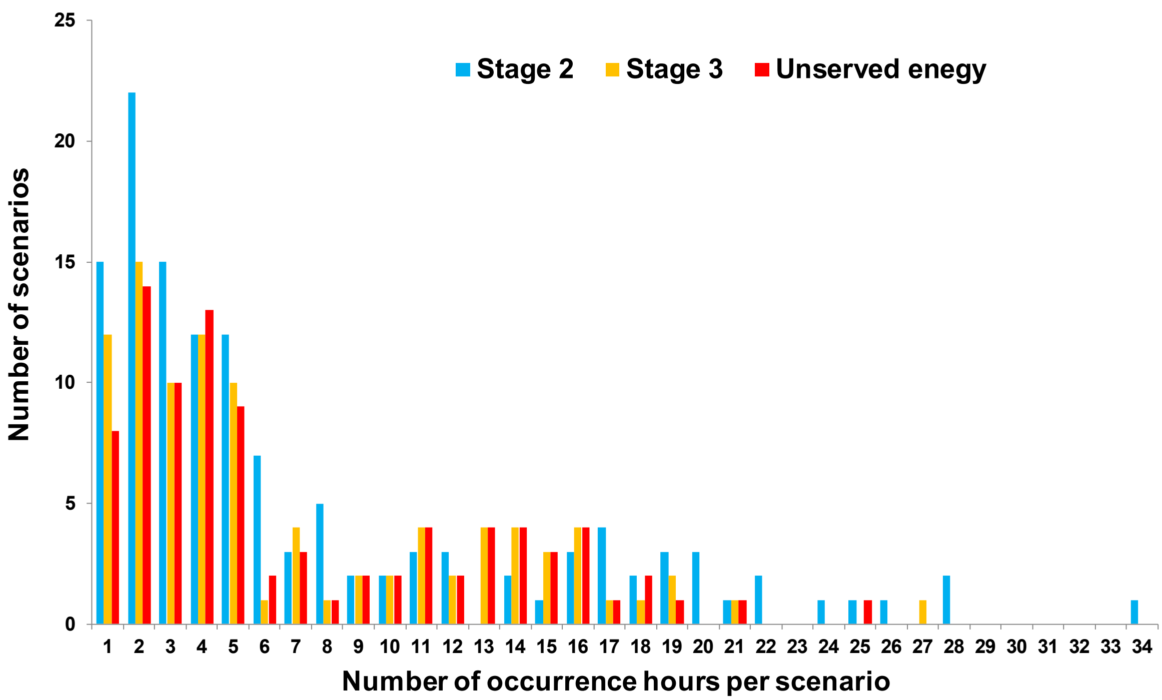


Figure 18 shows scenario occurrences with operating reserves at stage 2, stage 3 and unserved energy.

To further assess resource adequacy for the summer period, the Minimum Unloaded Capacity Margin value, equal to the lowest unload capacity margin in all 2,928 hours in each scenario, is determined for each of the 2,000 scenarios. The MUCM values from the base case range from a high of 15 percent down to the lowest result of zero in *Figure 19*. The zero result represents the most extreme hourly supply and demand condition within the

2,000 scenarios considered where in addition to the UCM at zero, there is an amount of energy that is not served. One or more hours of unserved energy were found in 91 out of the 2,000 scenarios. *Figure 20* shows the occurrence hour of MUCM less than or equal to 6 percent with the solar generation profile. The MUCM has the highest level of occurrences at hour ending 20:00, when solar generation has reached zero.

Figure 19

ISO Minimum Unloaded Capacity Margin for base case

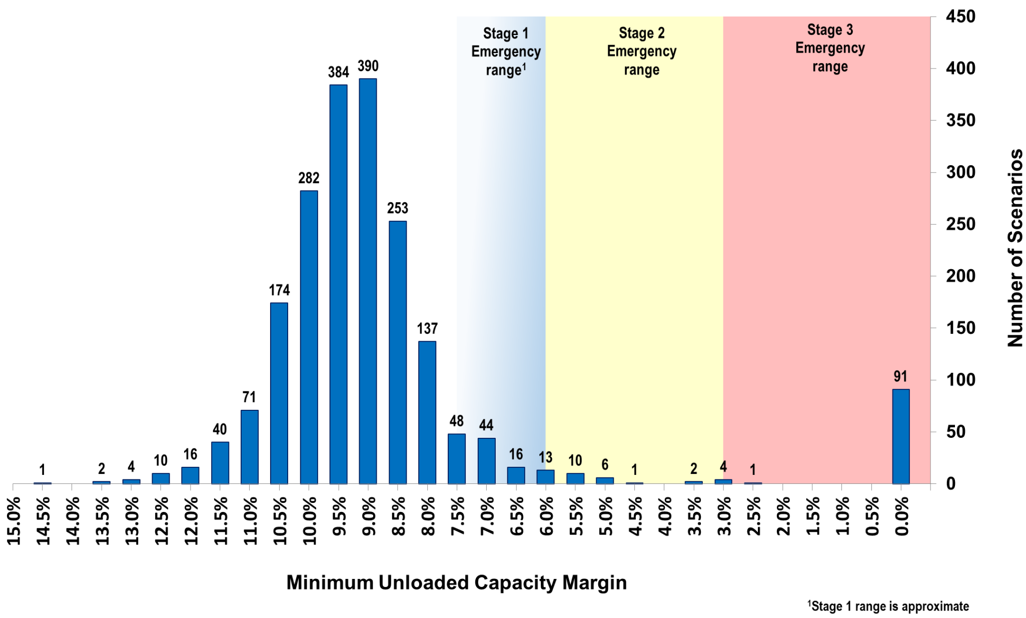


Figure 19 shows distribution of summer ISO MUCM for base case.

Figure 20

Base case MUCM hour of occurrence when 6 percent or less

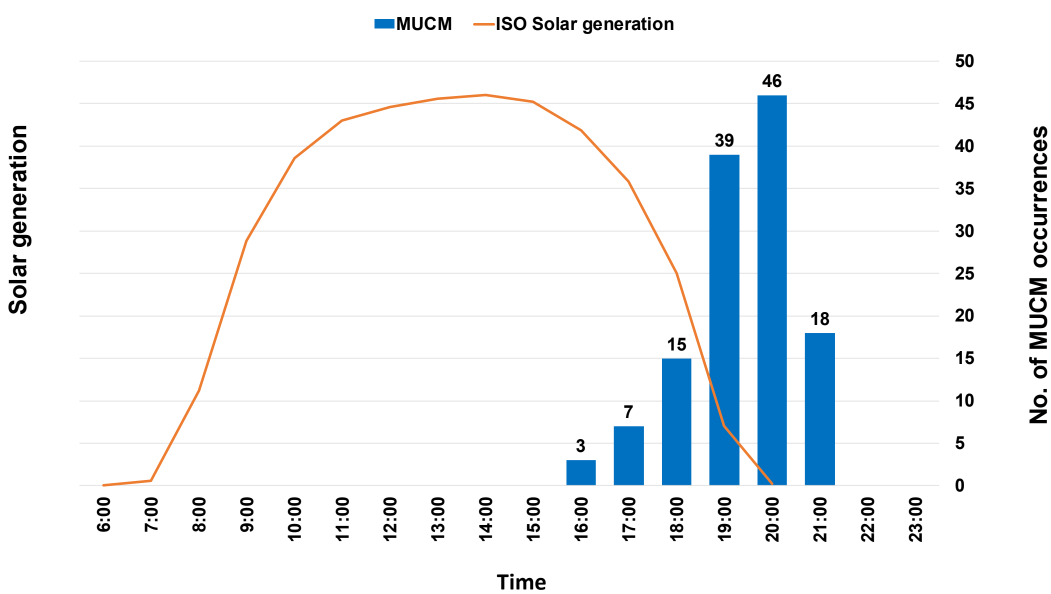


Figure 20 shows the occurrence hour of MUCM less than or equal to 6 percent and solar generation for base case.

Figure 21 shows the base case occurrences of unserved energy and the corresponding ISO load levels. The maximum unserved energy is 6,514 MW in August. The ISO loads when unserved energy occurs range from 45,922 MW to 55,587 MW.

Figure 21

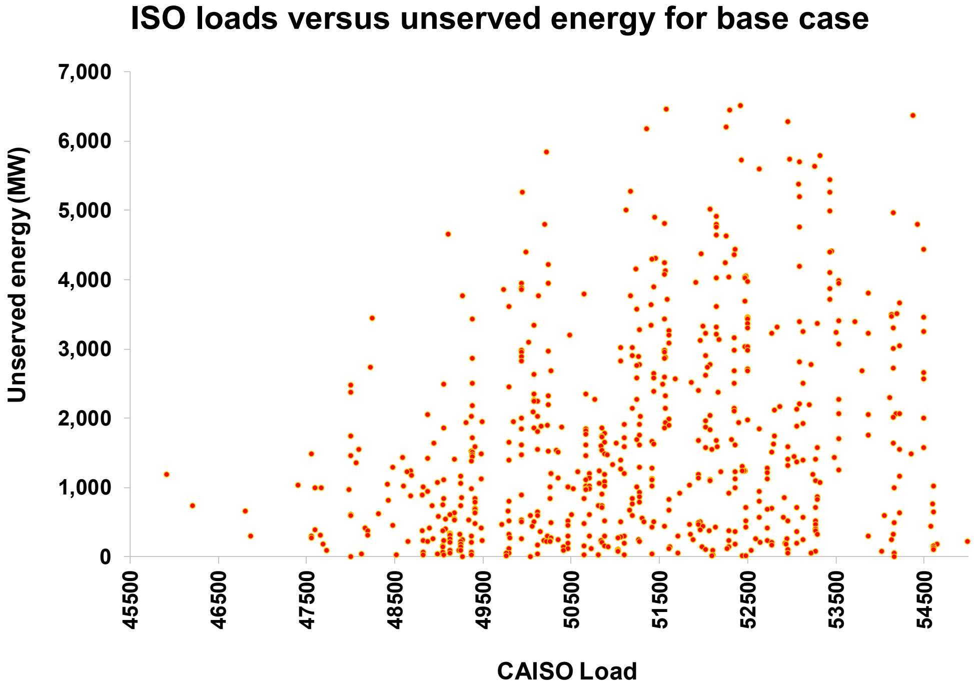


Figure 21 shows ISO unserved energy vs ISO loads for base case.

Ancillary Service and Flexible Capacity Adequacy

In addition, to assess system capacity adequacy, the PLEXOS model assesses the ancillary service and flexible capacity adequacy in the ISO market. *Table 15* and *Figure 22* show the base case results where the ISO system has a 17.8 percent probability of a load following up shortage, based on 355 scenarios that produced an hour or more of the shortage, a 12.6 percent probability of a spinning shortage, based on 251 scenarios that produced an hour or more of the shortage, and a 5.7 percent probability of a regulation up shortage based on 114 scenarios that produced one hour or more of a potential shortage.

The model's load following shortfall result is an indicator of tightness of dispatch capability. In actual real time operations a load following shortfall occurs and impacts ability to meet demand only when actual intra hour variability and uncertainty needs materialize. A load following shortfall does not have an operational impact when potential intra-hour uncertain and variability do not materialize. Therefore, load following shortfalls observed in hourly production simulations may only have a minimal operational impact. However, if a load following shortfall were to occur when actual intra hour variability and uncertainty needs do materialize, prices may rise and in some cases it may be necessary to rely on regulation or operating reserve to maintain balance between supply and demand. Otherwise, the ISO system may face operational challenges maintaining frequency within required limits. The scarcity of ancillary service and flexible capacity could cause NERC Control Performance Standard 1 (CPS1) violations, frequency deviation, increased area control error, and high scarcity prices.

Table 15

Probability of ancillary service and flexible capacity shortfall for base case

AS and LFU Shortfall	Shortfall Probability	Number of Shortfall Case
Load following up	17.8%	355
Spinning	12.6%	251
Regulation up	5.7%	114

Figure 22

Scenarios with regulation up, spinning and load following up shortage for base case

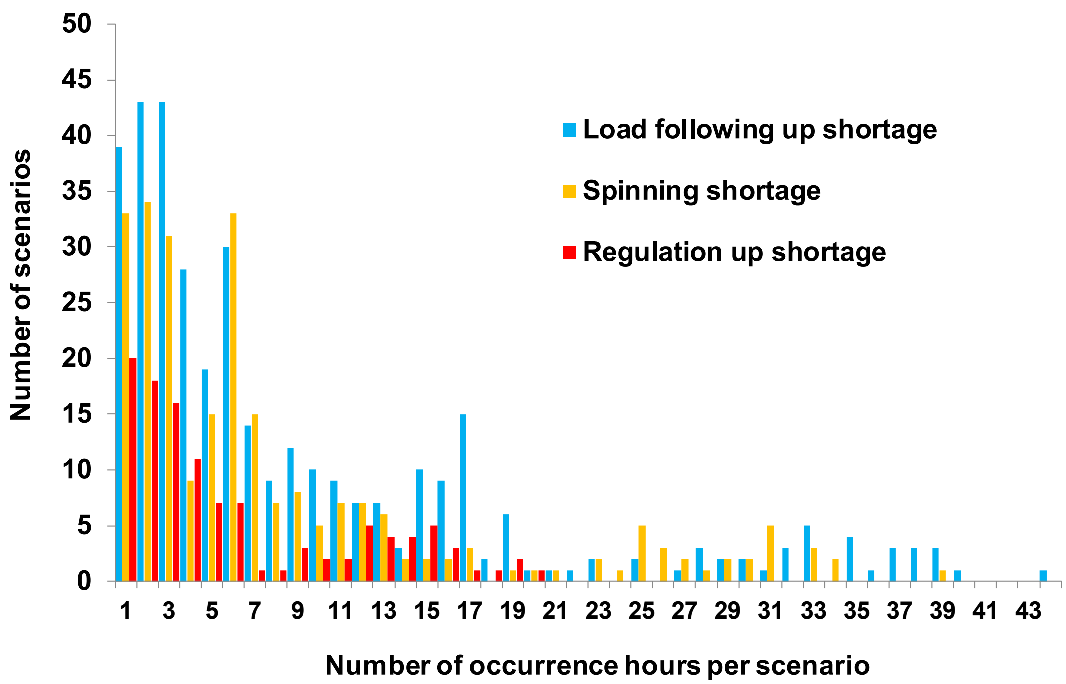


Figure 22 shows scenario occurrences with regulation up, spinning and load following up shortage for base case.

Sensitivity Case Study

System Capacity Adequacy

To understand the vulnerability of the ISO system to potential limitations of net imports, a sensitivity case was modeled using the more conservative net import nomogram. The ISO net imports were capped at the average RA net import levels: 3,922 MW in June, 5,340 MW in July, 6,095 MW in August, and 5,921 MW in September.

Table 16 and *Figure 23* show the sensitivity case results where the ISO system has an 14.1 percent probability of operating at stage 2, based on 281 scenarios that produced at least one hour of stage 2 emergency conditions, a 12.5 percent probability at stage 3, based on 249 scenarios that produced an hour or more of stage 3 emergency conditions, and a 12.4 percent probability with unserved energy, based on 247 scenarios showing at least one hour of unserved energy.

Table 16

Probability of system capacity shortfall for sensitivity case

System Capacity Shortfall	Shortfall Probability	Number of Shortfall Case
Stage 2	14.1%	281
Stage 3	12.5%	249
Unserved energy	12.4%	247

Figure 23

Scenarios with stage 2, stage 3 and unserved energy for sensitivity case

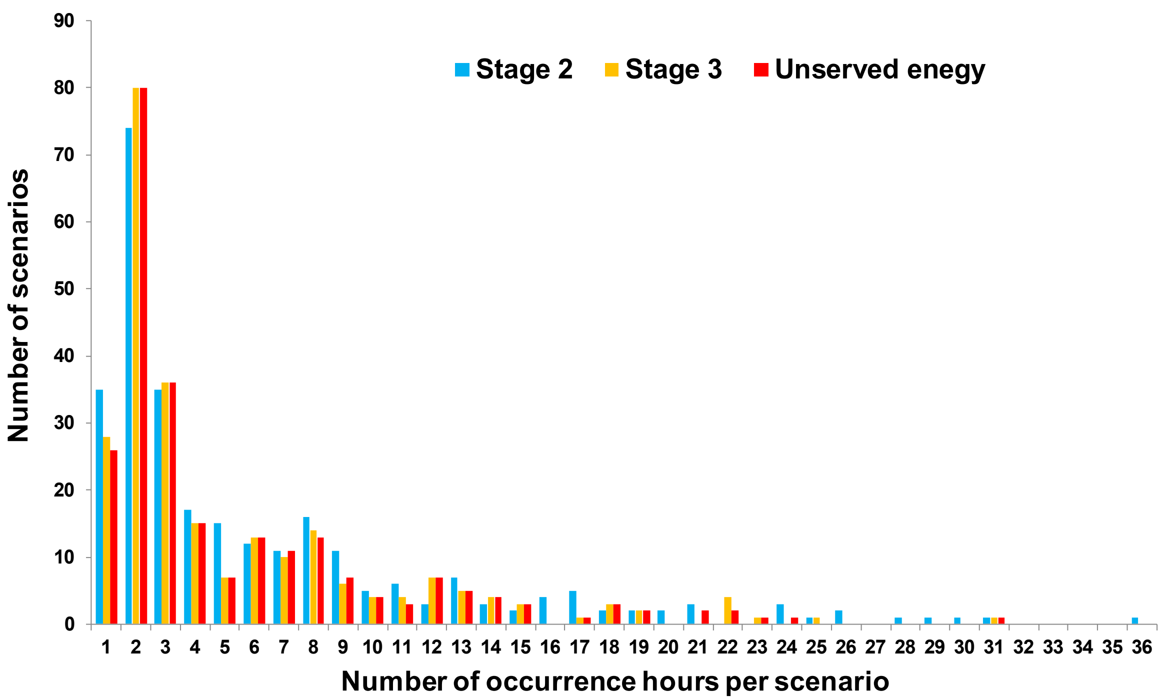


Figure 23 shows occurrences with operating reserves at stage 2, stage 3 and unserved energy for sensitivity case.

Figure 24 shows the sensitivity case distribution of MUCM values ranging from a high of 15 percent down to the lowest result of zero. The median value is 10.0 percent. *Figure 25* shows the distribution of the hour when each MUCM less than or equal to 6 percent occurred in comparison to the hours of solar generation during the 2021 summer peak day for sensitivity case.

Figure 24

ISO Minimum Unloaded Capacity Margins for sensitivity case

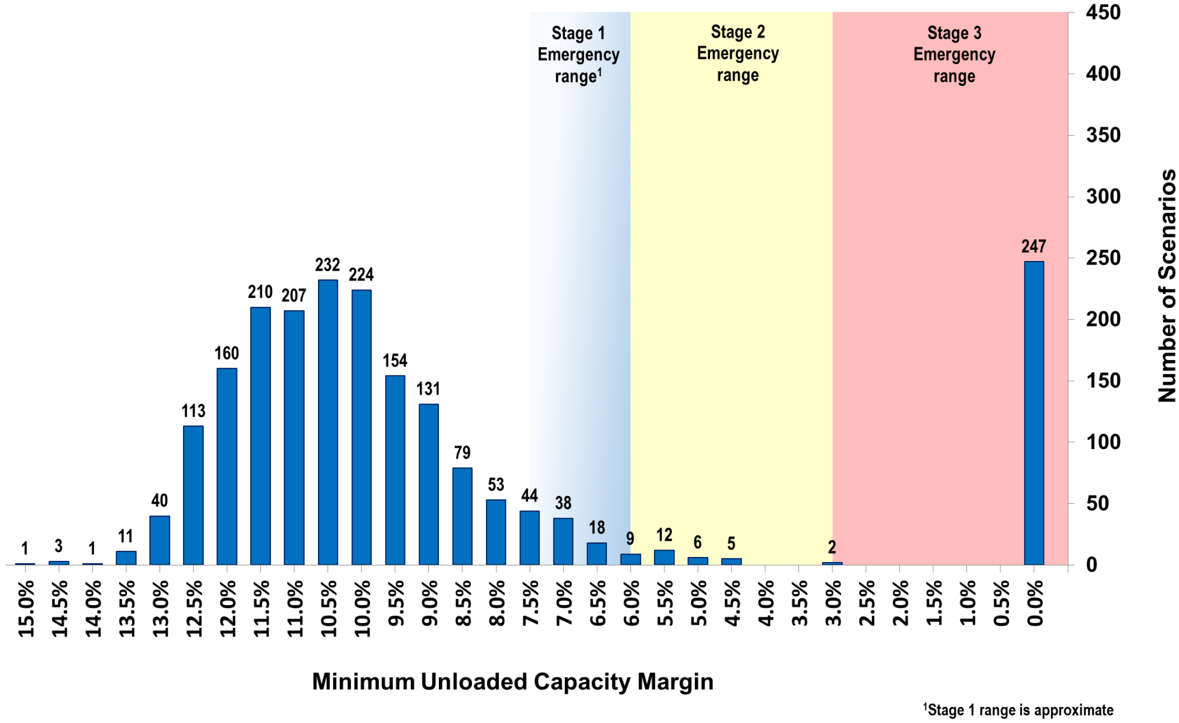


Figure 24 shows distribution of summer MUCM for the ISO for sensitivity case.

Figure 25

Sensitivity case MUCM hour of occurrence when 6 percent or less

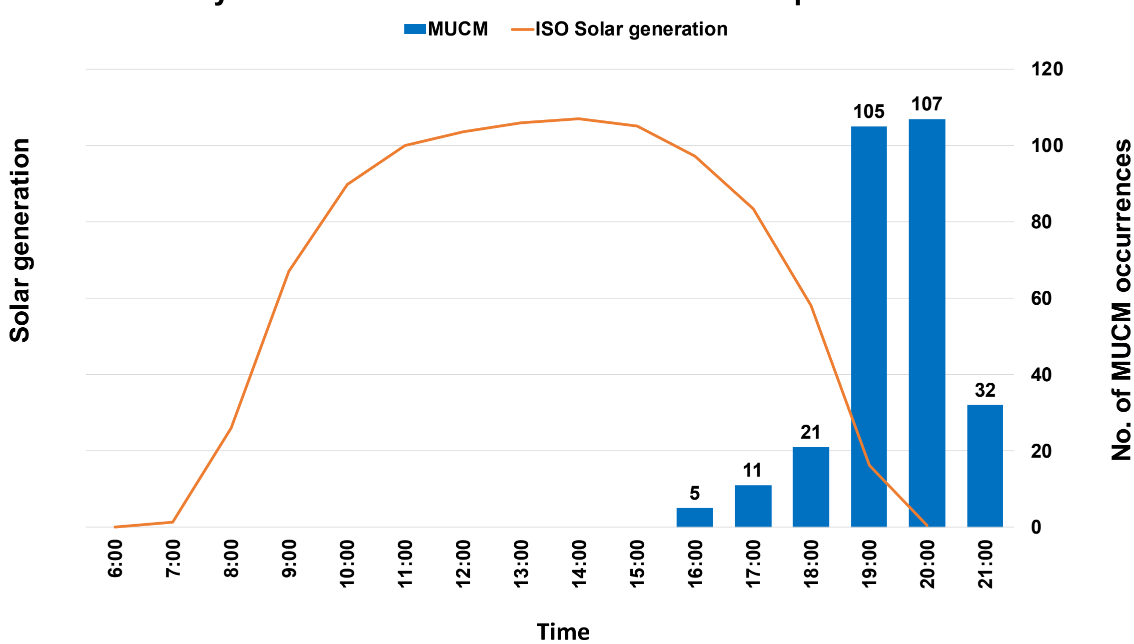


Figure 25 shows the occurrence hour of MUCM less than or equal to 6 percent and solar generation for sensitivity case

Figure 26 shows the sensitivity case occurrences of unserved energy and the corresponding ISO load levels. The maximum unserved energy is 6,524 MW in August. The ISO loads when unserved energy occurs range from 45,969 MW to 55,587 MW.

Figure 26

ISO loads versus unserved energy for sensitivity case

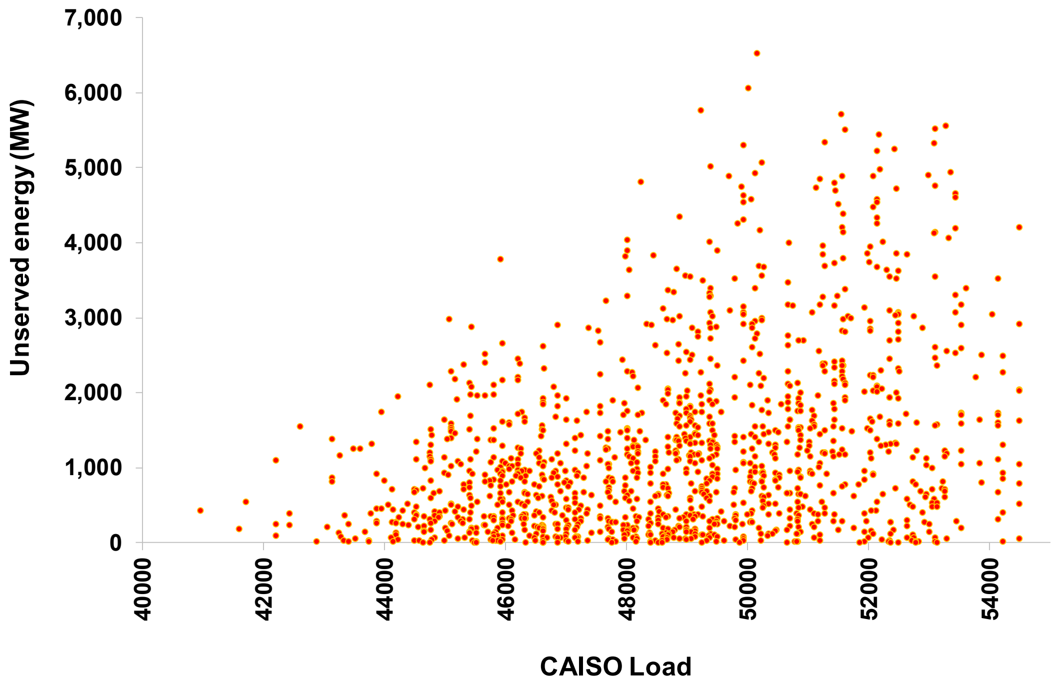


Figure 26 shows ISO unserved energy vs ISO loads for sensitivity case.

Ancillary Service and Flexible Capacity Adequacy

Table 17 and Figure 27 show the sensitivity case results where the ISO system has a 49.5 percent probability of operating in a load following up shortage, based on 989 scenarios that produced at least one hour of shortage, a 32.1 percent probability of a spinning shortage, based on 641 scenarios that produced an hour or more of shortage, and a 15.7 percent probability of a regulation up shortage, based on 313 scenarios that produced an hour or more of shortage.

Table 17

Ancillary service and flexible capacity shortfalls for sensitivity case

AS and LFU Shortfall	Shortfall Probability	Number of Shortfall Case
Load following up	49.5%	989
Spinning	32.1%	641
Regulation up	15.7%	313

Figure 27

Ancillary service and load following up shortages for sensitivity case

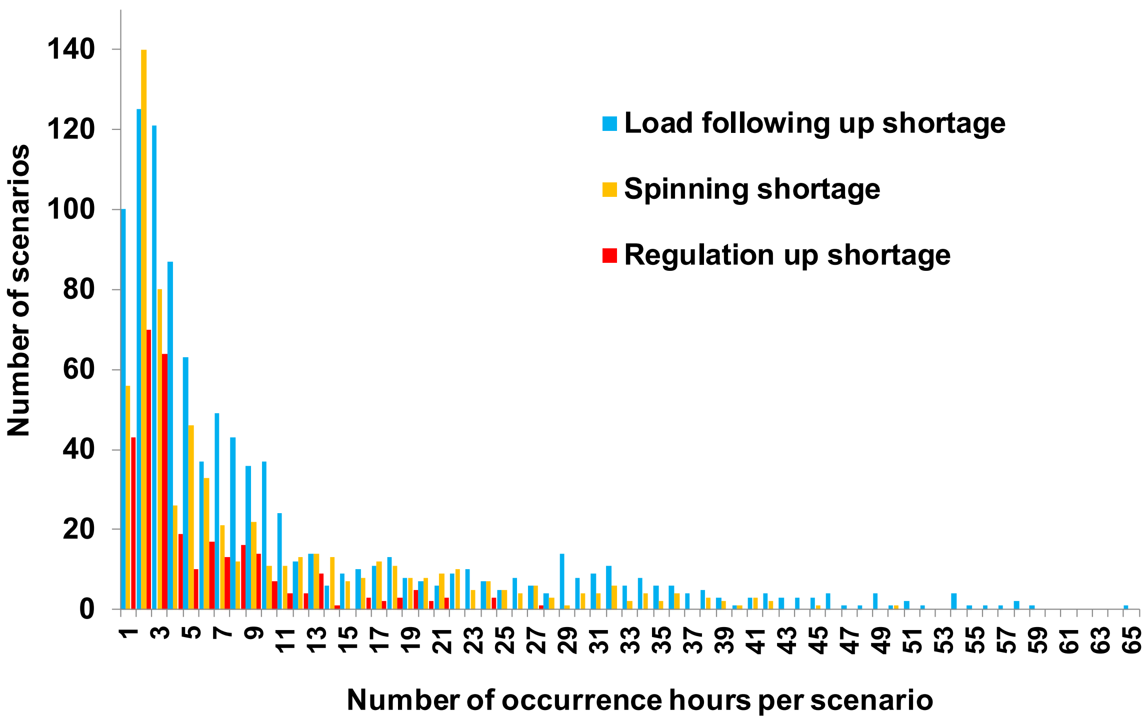


Figure 27 shows scenario occurrences with ancillary service and load following up shortages for sensitivity case.

Table 18 compares the probability of an ISO system capacity shortfall between the base case and the sensitivity case, revealing the criticality of net imports to the ISO during system peak hours in high-load conditions. If the ISO is limited to the more conservative net import levels of the sensitivity case, the probability of having to shed firm load to maintain required operating reserves is significantly increased. This indicates that the ISO will be at the greatest operational risk during a late-summer widespread heat wave that results in low net imports due to high peak demands in its neighboring balancing authority areas, concurrent with the diminishing effective load carrying capability of solar resources and the diminishment of hydro generation.

Table 18

Probability of ISO system capacity shortfall

Base case compared to sensitivity case

Result	Base Case	Sensitivity Case
Stage 2	6.4%	14.1%
Stage 3	4.8%	12.5%
Unserved energy	4.6%	12.4%

Deterministic Stack Analysis

In a process of assessing adequate resource procurement targets and minimum resource needs under the CPUC Resource Adequacy program, the ISO performed a deterministic stack analysis. In addition to the stochastic modeling described above, the ISO deterministic stack analysis is included to provide an additional perspective on the amount of capacity the ISO is expecting to be available for summer 2021 and the level of reliability that is anticipated under various load levels and import conditions.

To maintain reliability, the ISO must comply with several North American Electric Reliability Corporation (NERC) and Western Electricity Coordinating Council (WECC) standards in real-time. BAL-002-WECC-2a requires the ISO to carry approximately 6 percent of expected load as contingency reserves. The contingency reserves required under BAL-002-WECC-2a cannot be used for other types of operational needs other than contingencies unless the ISO is in an energy emergency alert. In addition, the ISO also requires unloaded capacity to meet operational needs like frequency response and regulation pursuant to BAL-003-2 and BAL-001-2. To assess the ISO's ability to maintain those reserve margins necessary for reliable service in real time operation, the ISO considered the capacity needs taking into account the overall outage rate of the existing fleet, which is currently about 7.5 percent. The ISO also based the deterministic assessment on meeting a 1-in-5 load forecast level. The combined effect of these requirements established a threshold need for a 17.5 percent margin above a 1-in-2 load forecast level.

The ISO's analysis consisted of two steps; first assessing the need for capacity required to meet the contingency provisions of BAL-002-WECC-2a, and then assessing the ability of existing and forecast resources to meet those needs in the summer of 2021. From an RA planning perspective the ISO considers that a 17.5 percent margin applied to a 1-in-2 load level is necessary to provide reliable service pursuant to the contingency reserve provisions. This consists of the 6 percent operating reserve contingency requirement set out in the standard, allowance for 7.5 percent for forced outages, and a 4 percent margin for higher loads than an average 1-in-2 system load forecast. The 4 percent allowance for load accommodates forecast loads up to a 1-in-5 level above the 1-in-2 forecast used as a baseline.

Figure 28 shows the result of the deterministic stack analysis for the month of September, 2021, at 8 pm, the month and hour of the greatest supply risk. The amount of new resources shown in *Figure 28* are based on a CPUC presentation[32] that shows 2,388 MW of expected new capacity coming online between August 1 2020 and August 1, 2021. The 2,388 was adjusted to 2,230 by removing the solar resource capacity not associated with a storage component to account for the 8 pm time of day when solar generation is not available. The three bars of stacked resources portray three scenarios of progressively increasing resource amounts. Moving from left to right, the first bar represents resources similar to the stochastic sensitivity case, where imports are limited to the average of the last six-years of RA imports[33] procured by the load serving entities to meet their collective RA obligations. The middle bar represents an increase in the RA import level to 8,500 MW, the highest amount procured for the month of September over the last 6 years. The bar on the right further increases the level of imports from the middle bar by assuming an additional 1,000 MW of non-RA economic imports during the peak period. As with the stochastic sensitivity results, *Figure 4* demonstrates the importance of imports above typical RA import levels for meeting 1-in-2 and higher peak demand conditions during late summer.

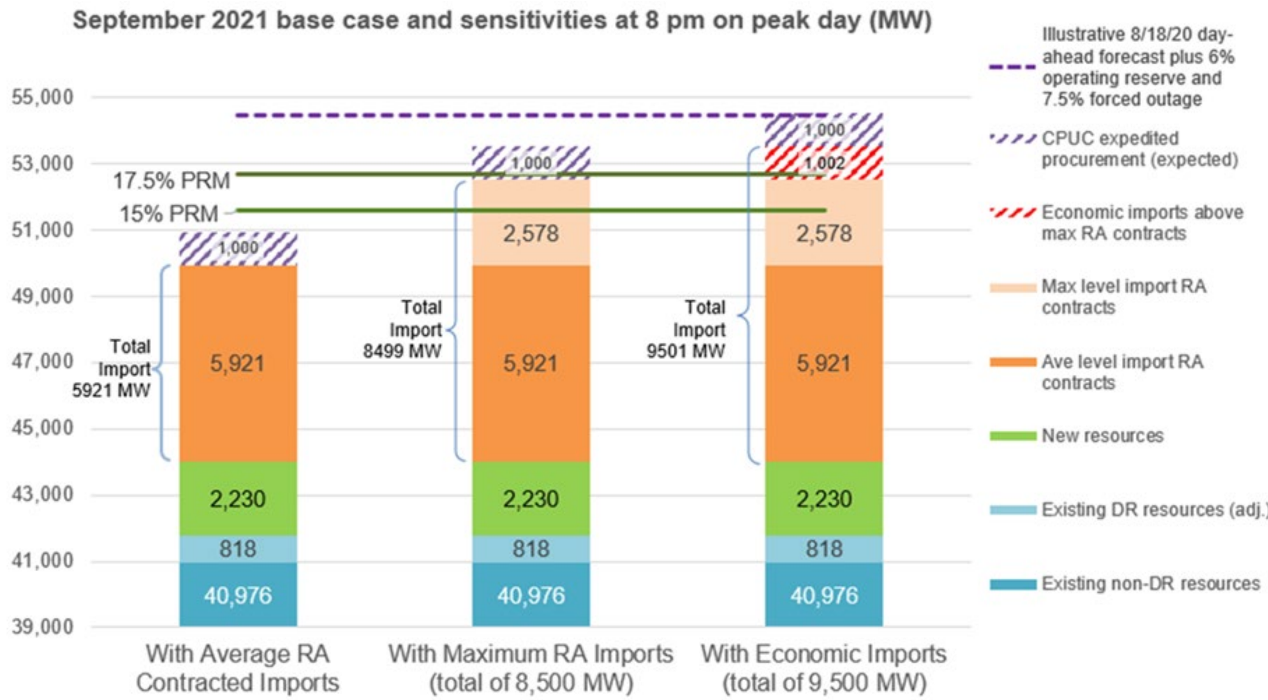
- The bar on the left shows that if the system is limited to imports of 5,921 MW, the 15 percent planning reserve margin (PRM) associated with 1-in-2 load levels cannot be met in September;
- The middle bar shows that if system imports reach 8,499 MW, approximately 2,600 MW greater than the typical RA procurement levels, 1-in-5 loads and the 17.5 percent PRM can be met;
- The bar on the right demonstrates that loads equivalent to the day-ahead forecast for August 18, 2020, the day of the ISO 2020 summer peak, would only be met if imports reach to a level of approximately 3,600 MW greater than the typical RA procurement levels and forced outages do not exceed the normal 7.5 percent rate.

[32] https://www.google.com/url?client=internal-element-cse&cx=001779225245372747843:e2wnztai65q&q=https://www.cpuc.ca.gov/WorkArea/DownloadAsset.aspx%3Fid%3D6442466860&sa=U&ved=2ahUKEwjWzYWMgKfwAhXjFDQIHeV-AyAQFjAAegQIARAB&usg=AOvVaw0ZSlD_aBQW-I1GlJ_Zjqle

[33] The 2015 – 2020 average of the total import capacity procured by all load serving entities to meet their RA obligation is 5,921 MW.

Figure 28

ISO stack analysis for September 2021
(PRM levels based on CEC 1-in-2 load forecast plus planning reserve margin)



Impacts of the Aliso Canyon Gas Storage Operating Restrictions

Natural gas needs in Southern California are met by a combination of major gas pipelines, distribution gas infrastructure and gas storage facilities. Four major gas storage facilities are located in the Southern California Gas system, the largest of which is the Aliso Canyon facility located in Los Angeles County. Aliso Canyon and other gas storage facilities are used year-round to support the delivery of gas to core and non-core users. Among the non-core users are electric generators, which helps meet electric demands throughout the region.

Following a significant natural gas leak in late 2015, the injection and withdrawal capabilities of the Aliso Canyon were severely restricted. These restrictions impacted the ability of pipeline operators to manage real-time natural gas supply and demand deviations, which in turn could have had impacts on the real-time flexibility of natural gas-fired electric generators in Southern California. This primarily impacted resources operated in the Southern California Gas Company (SoCalGas) and San Diego Gas and Electric (SDG&E) service areas, collectively referred to as the SoCalGas system.

Aliso Canyon directly supplies 17 gas-fired power plants with a combined total 9,800 MW of electric generation in the Los Angeles basin and indirectly impacts 48 plants with a combined total 20,120 MW of electric generation across Southern California. There are limitations in attempting to shift power supply from resources affected by Aliso Canyon to resources that are not affected because of factors such as local generation requirements, transmission constraints and other resource availability issues.

To address the continued operating restrictions at Aliso Canyon, the ISO and the California Public Utilities Commission (CPUC) have taken separate but complementary actions to manage the current situation while the state considers the long-term need and viability of the storage facility.

Starting in summer 2016, the ISO received approval from the Federal Energy Regulatory Commission (FERC) to temporarily implement three operational tools and market mechanisms to mitigate the electric system reliability risk posed by restricted operations at Aliso Canyon. The first was a maximum gas constraint tool to manage generator gas consumption in Southern California within bounds established by SoCal Gas. The second was the ability for the ISO to manually override the competitive path assessment to determine if transmission constraints are uncompetitive. This action allows supply limitations to be reflected in the market power mitigation process. Lastly, the ISO could suspend virtual bidding if the maximum gas constraint was causing market inefficiencies. On December 31, 2019, the ISO received approval from the FERC to make permanent the three main operational tools and market mechanisms.[34] In addition, the ISO worked closely with SoCalGas to develop enhanced coordination procedures where SoCalGas adjusted natural gas balancing rules to provide stronger incentives for natural gas customers, such as electric generators, to align their natural gas schedules and burns.

On April 1, 2021, SoCalGas published its Summer 2021 Technical Assessment, which concluded that conditions remained about the same as last year and that SoCalGas will be able to meet the forecasted summer peak day demand, even without supply from Aliso Canyon.[35] In addition, SoCalGas has more flexibility to use Aliso Canyon to balance the system and ease energy price spikes pursuant to revisions made by the CPUC on July 23, 2019 under the Aliso Canyon Withdrawal Protocol to remove its classification as "an asset of last resort."[36]

Once Through Cooled Generation

On May 4, 2010, the State Water Resources Control Board (SWRCB) adopted a policy on the use of coastal and estuarine waters for power plant cooling. The 2010 policy applies to 19 power plants located in both the ISO and LADWP Balancing Authority Areas, some of which have already retired. Together, these plants had the ability to withdraw more than 15 billion gallons per day from the state's coastal and estuarine waters using a single-pass system, also known as once-through cooling (OTC). Table 19 shows the 16 power plants

[34] Federal Energy Regulatory Commission, Order Accepting Tariff Revisions, ER20-273-000, December 31, 2019.

[35] Southern California Gas Company, Summer 2021 Technical Assessment, April 1, 2021.

[36] Aliso Canyon Withdrawal Protocol: https://www.cpuc.ca.gov/uploadedFiles/CPUCWebsite/Content/News_Room/NewsUpdates/2019/UpdatedWithdrawalProtocol_2019-07-23%20-%20v2.pdf

located in the ISO Balancing Authority that are subject to the Policy. Of the OTC units' 17,302 MW of generating capability affected by the policy, 11,304 MW are in compliance. The remaining 3,758 MW of gas-fired generation will be required to repower, retrofit or retire to be in compliance by the end of 2021 and 2023, with Diablo Canyon retiring later in 2024 and 2025.

On November 30, 2020, the State Water Resources Control Board approved extending the OTC compliance date for Alamitos Units 3, 4, and 5, Ormond Beach Units 1 and 2, and Huntington Beach Unit 2 for three years through December 31, 2023, and Redondo Beach Units 5, 6, and 8 for one year through December 31, 2021 to address local and system-wide grid reliability concerns.[37] These system-wide grid reliability concerns come from the shifting daily peaks to later in the day when solar resources are not available to meet peak demand; the changes in the calculation of net qualifying capacity for wind and solar resources to be less than previously determined; an increase in reliance on the net imports over historical levels; and earlier-than-expected retirements of non-OTC resources. The necessity of additional power becomes imperative for summer peak during the hot days. On November 7, 2019, Decision D.19-11-016 was approved by commissioners of the CPUC, completing the Integrated Resource Plan process for R.16-02-007. D.19-11-016 directs 3,300 MW of new procurement from load serving entities under the CPUC's jurisdiction to ensure system-wide electric reliability. The decision also recommended that the State Water Board consider revising the OTC policy to extend the compliance dates for Alamitos Units 3, 4, and 5, Huntington Beach Unit 2, Redondo Beach Units 5, 6, and 8, and Ormond Beach Units 1 and 2.[38]

On March 26, 2021, the Statewide Advisory Committee on Cooling Water Intake Structures (SACCWIS) recommended that the State Water Resources Control Board extend the OTC Policy compliance date of Redondo Beach Units 5, 6 and 8 for two years through December 31, 2023.[39] The CPUC adopted D.21-02-028 on February 11, 2021, which directed the three investor-owned utilities to undertake expedited procurement for capacity that will be available to serve demand in the summer of 2021. Decision D.21-02-028 also anticipates a subsequent decision in R.20-11-003 to address 2022 capacity needs. While this proceeding and other CPUC procurement efforts are still ongoing, a comprehensive stack analysis conducted by the CPUC, ISO, and CEC indicates that additional procurement is needed to

[37] State Water Resources Control Board - Approval Letter https://www.waterboards.ca.gov/water_issues/programs/ocean/cwa316/docs/oal_approval_2020/oalapp.pdf and Final Amendment to the Water Quality Control Policy on the Use of Coastal and Estuarine Waters for Power Plant Cooling https://www.waterboards.ca.gov/water_issues/programs/ocean/cwa316/docs/otc_policy_2020/final_amendment.pdf

[38] https://www.waterboards.ca.gov/water_issues/programs/ocean/cwa316/saccwis/docs/final_report.pdf https://www.waterboards.ca.gov/water_issues/programs/ocean/cwa316/docs/otc_policy_2020/final_amendment.pdf

[39] Draft 2021 Report of the Statewide Advisory Committee on Cooling Water Intake Structures https://www.waterboards.ca.gov/water_issues/programs/ocean/cwa316/saccwis/docs/21draftreport.pdf

mitigate grid reliability concerns. The power generated by Redondo Beach will help offset projected system-wide shortfalls during periods of high energy demand.

Table 19

Generating Units Compliance with California Statewide Policy on the Use of Coastal and Estuarine Waters for Power Plant Cooling

Plant (Unit)	Owner	State Water Resources Control Board Compliance Date	Planned retirement Date by Generating Owners	Capacity (MW)	PTO Area
Compliance Plan Yet to be Implemented (Natural Gas Fired)					
Huntington Beach Units 2	AES	12/31/2023		226	SCE
Redondo Beach Units 5,6,8*	AES	12/31/2021		850	SCE
Alamitos Units 3,4,5	AES	12/31/2023		1,166	SCE
Ormond Beach Units 1 and 2	NRG	12/31/2023		1,516	SCE
			Total MW	**3,758**	
Notes*extension to 12/31/2023 is recommended by the SACCWIS at the SWRCB for consideration					
In Compliance**					
Huntington Beach Units 1	AES	1/31/2020		226	SCE
Alamitos Units 1,2,6	AES	1/31/2020		845	SCE
Redondo Beach Units 7	AES	10/1/2019		493	SCE
Encina Power Station Units 2-5	NRG	12/12/2018		840	SDG&E
Mandalay Units 1 and 2	NRG	2/15/2018		430	SCE
Encina Power Station Units 1	NRG	5/8/2017		106	SDG&E
Moss Landing Units 6 and 7	Dynegy	1/1/2017		1,500	PG&E
Pittsburg Units 5, 6 and 7	NRG	12/31/2016		1,159	PG&E
Huntington Beach Units 3-4	AES	12/7/2012		452	SCE
Humboldt	PG&E	Sept. 2010		105	PG&E
Potrero Unit 3	GenOn	2/28/2011		206	PG&E
South Bay	Dynegy	1/1/2011		702	SDG&E
Contra Costa Units 6 and 7	NRG	5/1/2013		674	PG&E
San Onofre Unit 2 & 3	SCE	6/7/2013		2,246	SCE
El Segundo Units 3	NRG	7/1/2014		335	SCE
El Segundo Units 4	NRG	12/31/2015		335	SCE
Morro Bay Units 3 and 4	Dynegy	2/5/2014		650	PG&E
			Total MW	**11,304**	
Notes**: these generating units were retired.					
Nuclear Plant to be in compliance					
Diablo Canyon unit 1	PG&E	11/2/2024		1,122	PG&E
Diablo Canyon unit 2	PG&E	8/26/2025		1,118	PG&E
			Total MW	**2,240**	
			Total of all OTC Units	**17,302**	

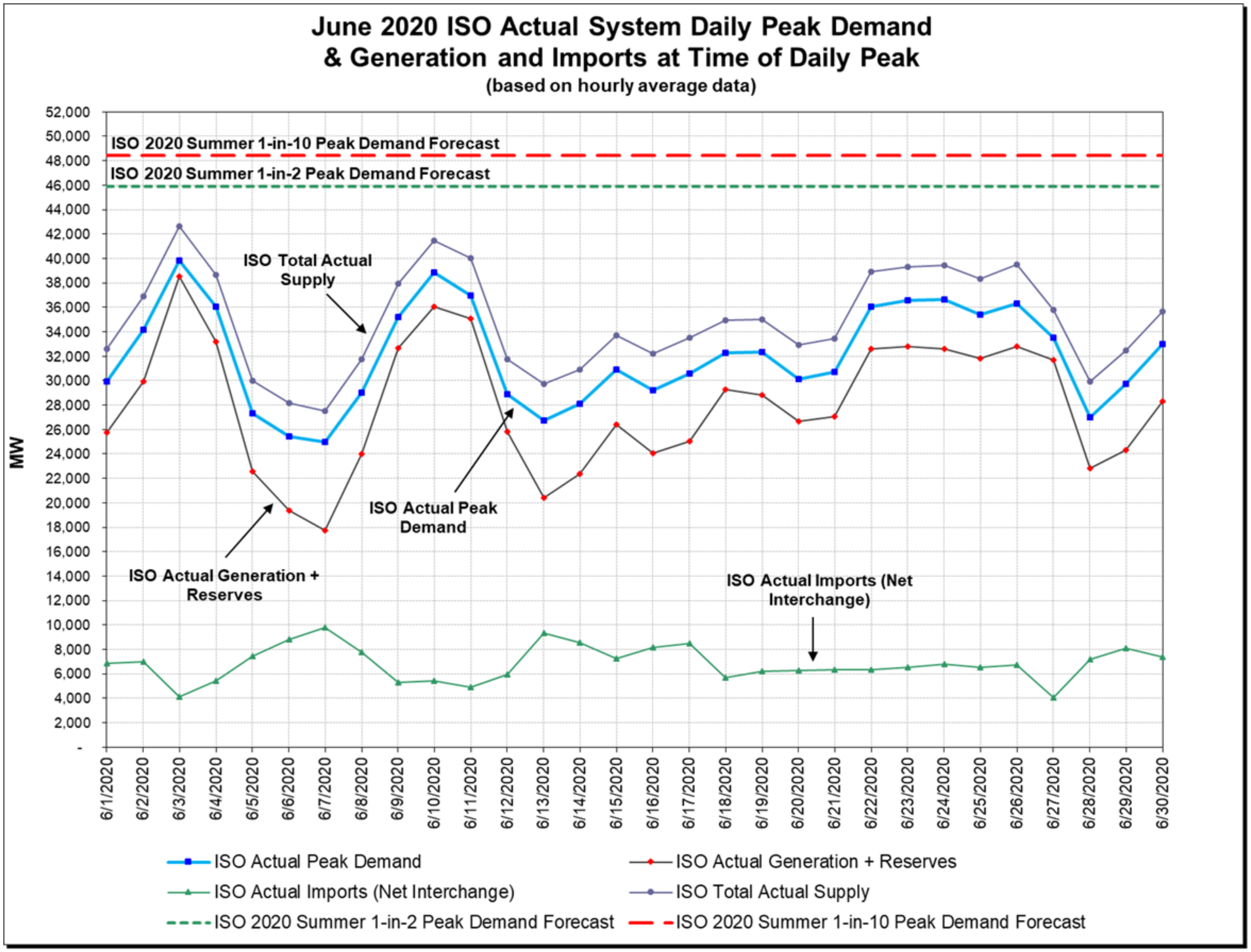
Technical Report Appendices

A. 2020 Summer Supply and Demand Summary Graphs

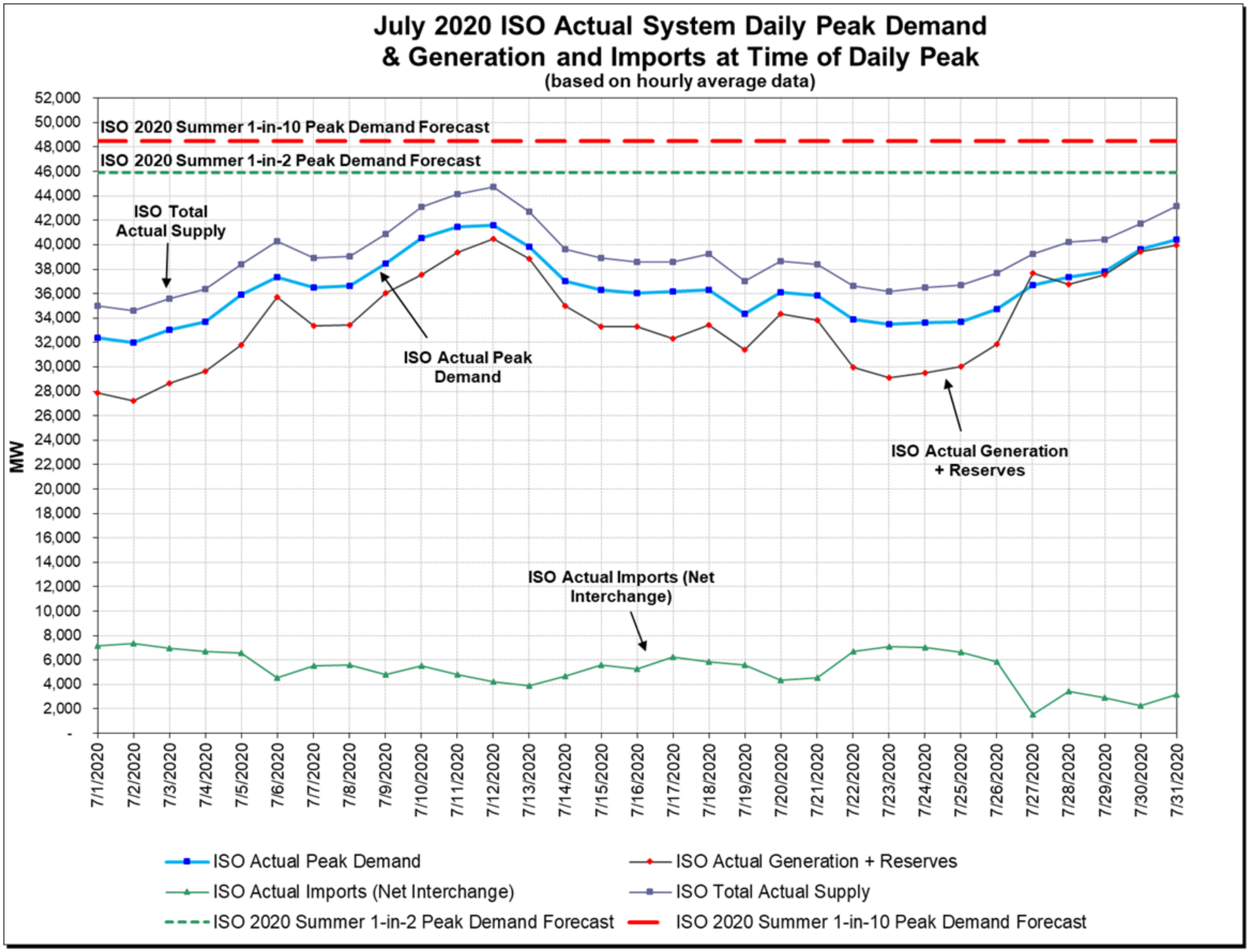
B. 2020 Summer Net Imports Summary Graphs

C. 2021 ISO Summer Maximum On-Peak Available Capacity by Fuel Type

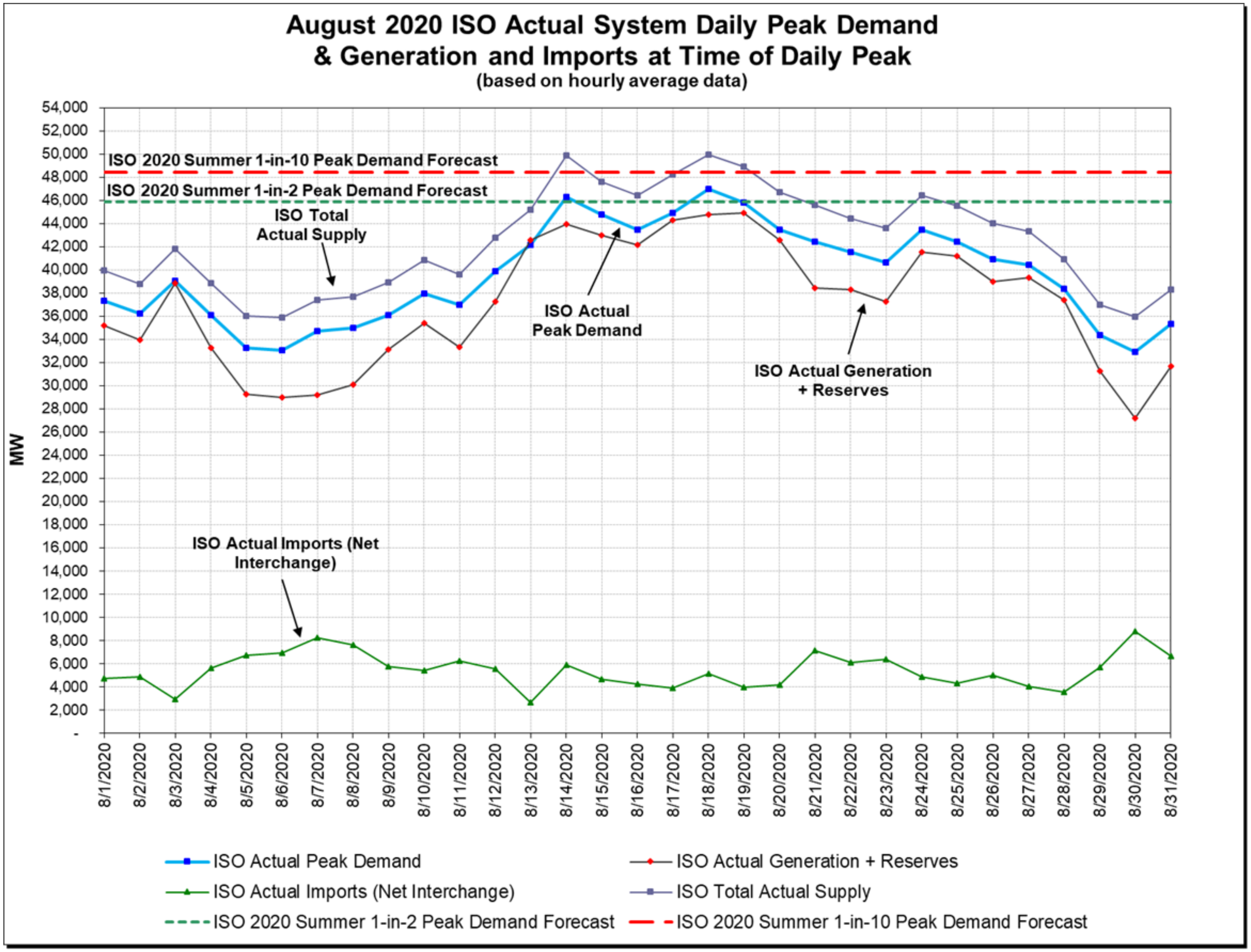
Appendix A: 2020 Summer Supply and Demand Summary Graphs



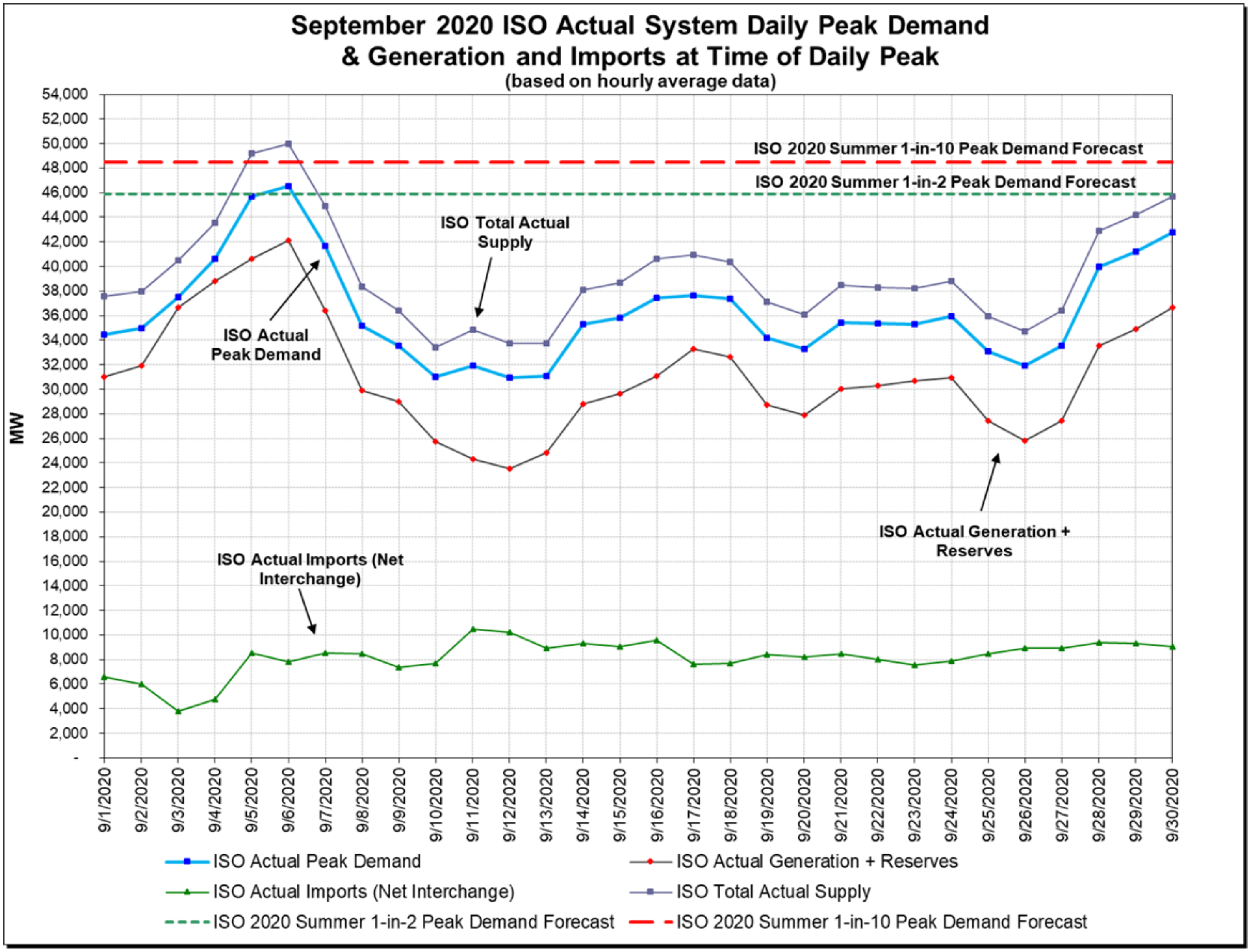
Appendix A: 2020 Summer Supply and Demand Summary Graphs



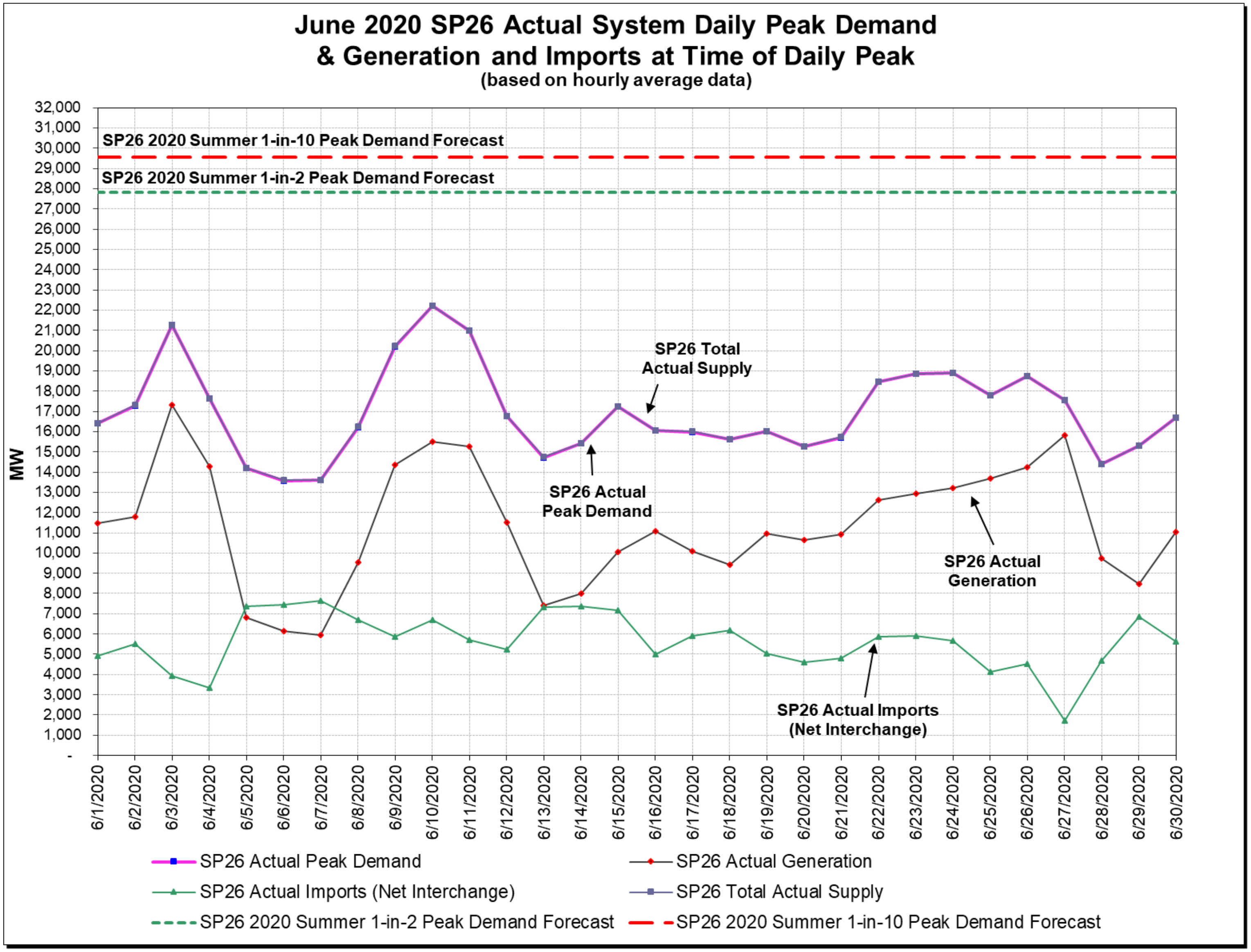
Appendix A: 2020 Summer Supply and Demand Summary Graphs



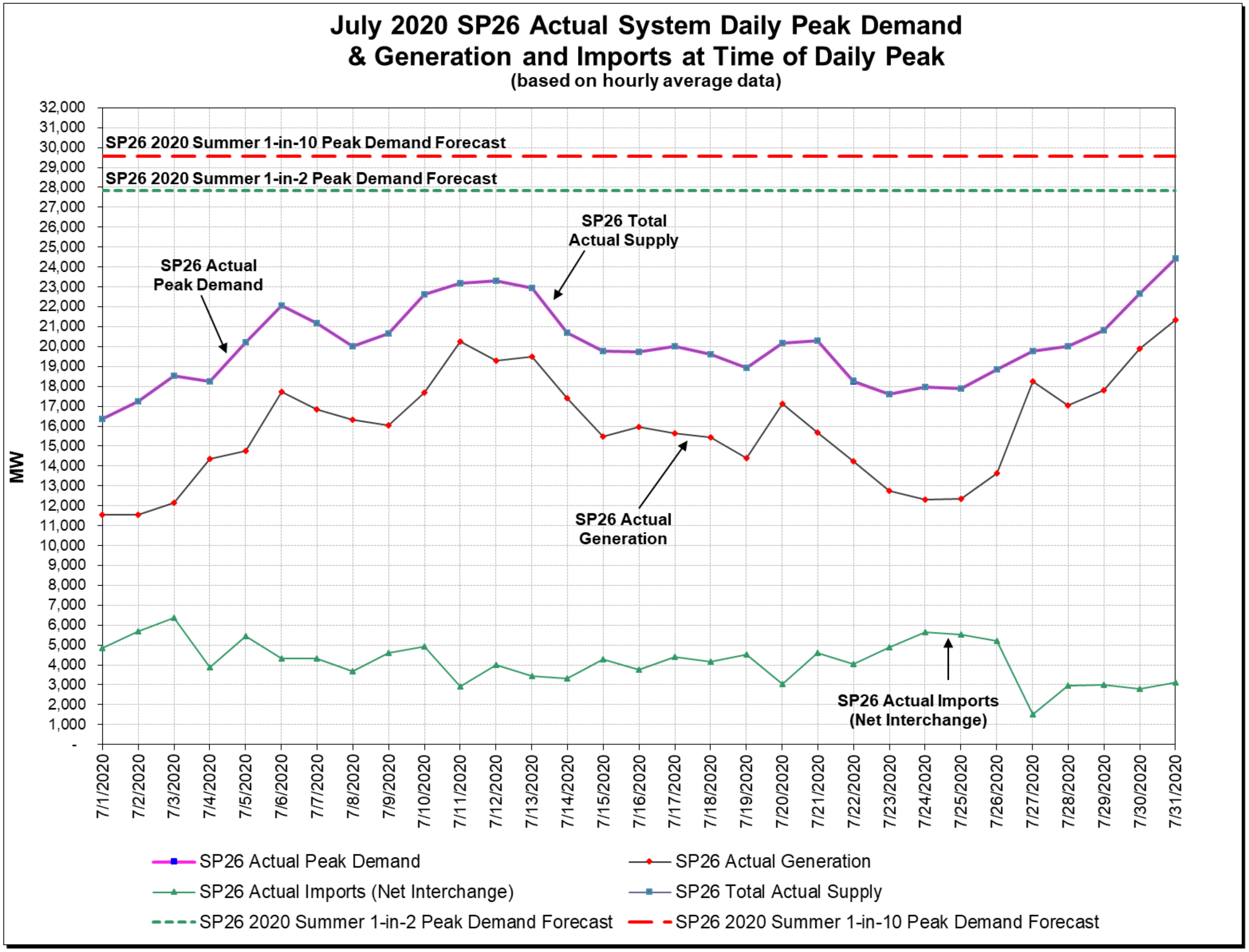
Appendix A: 2020 Summer Supply and Demand Summary Graphs



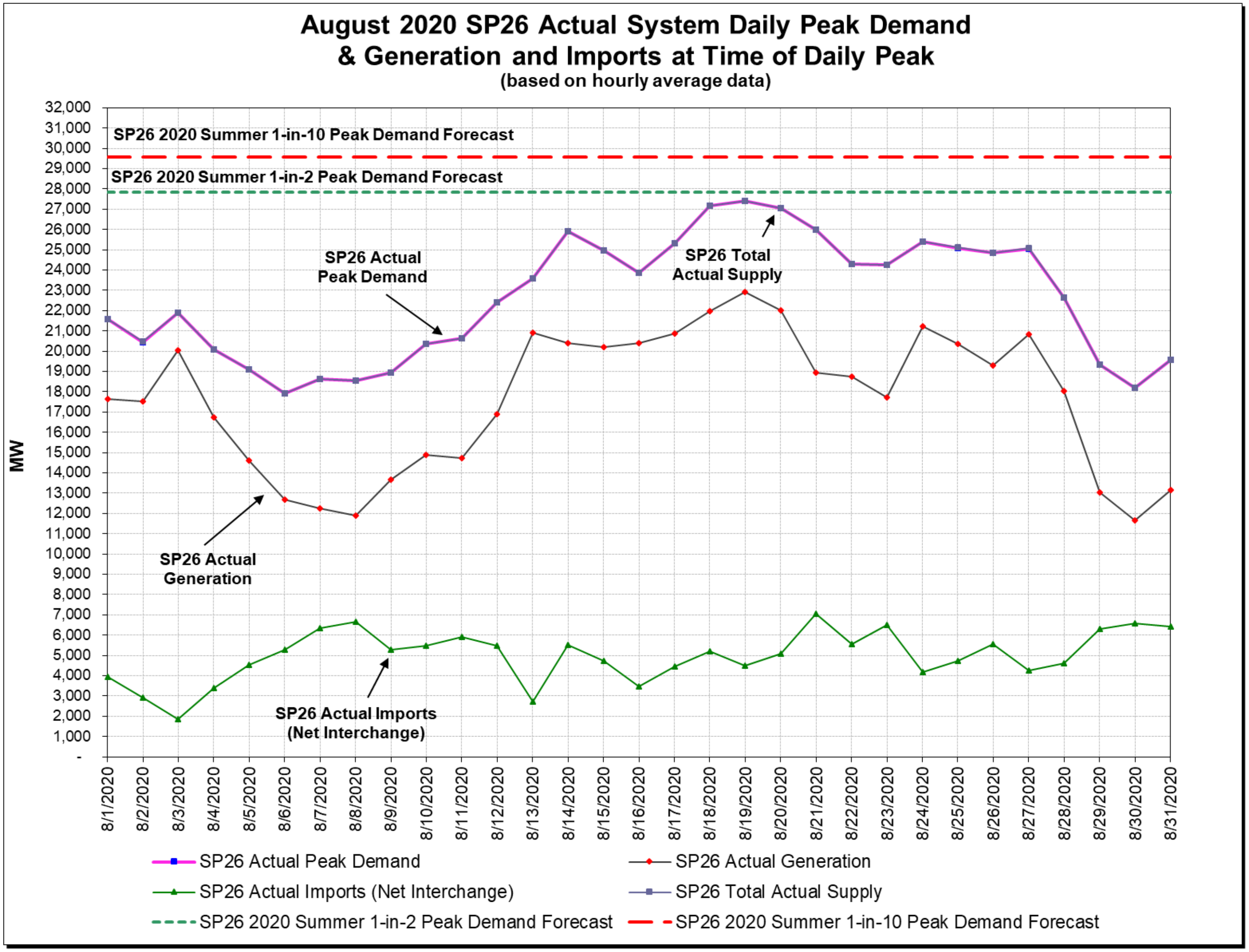
Appendix A: 2020 Summer Supply and Demand Summary Graphs



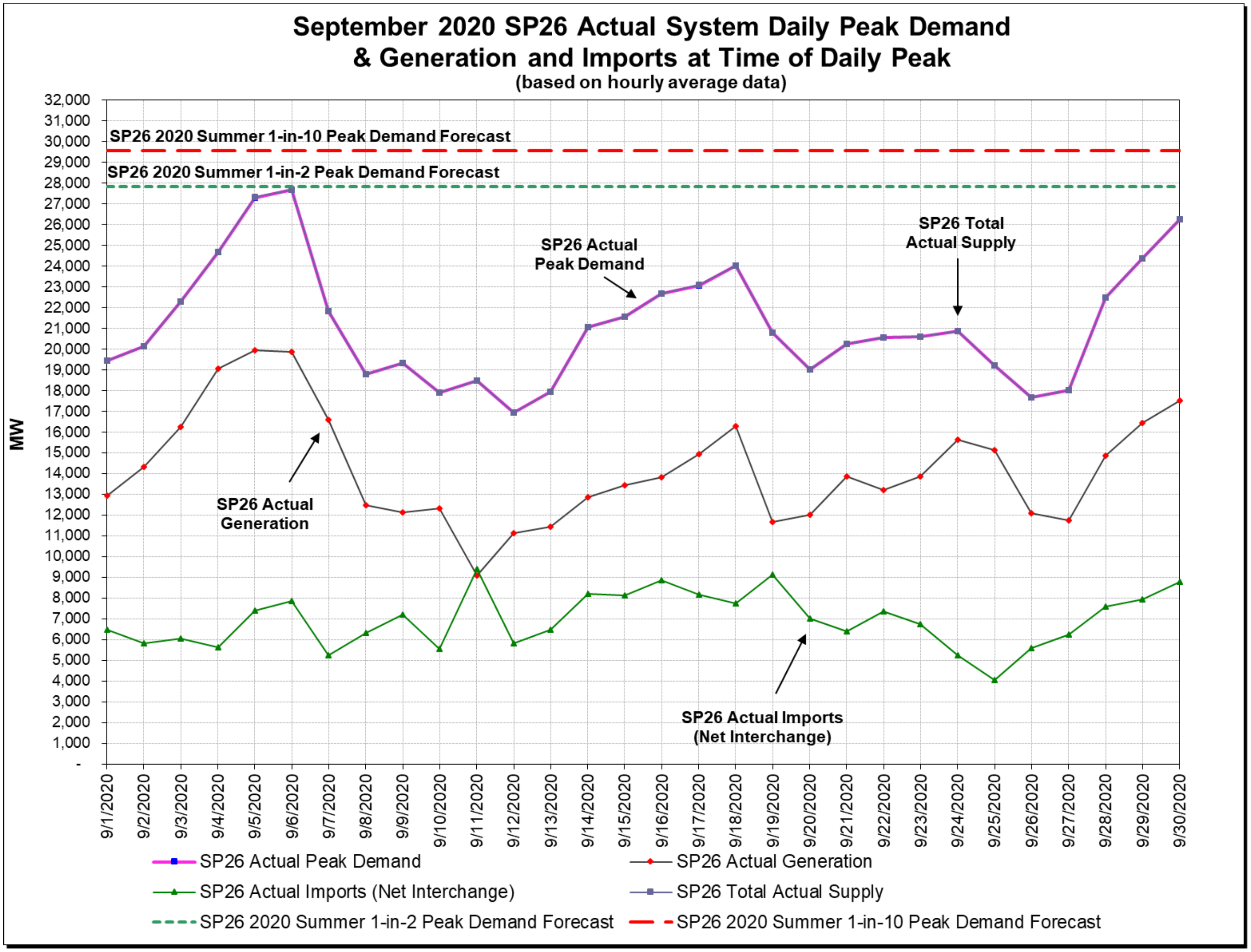
Appendix A: 2020 Summer Supply and Demand Summary Graphs



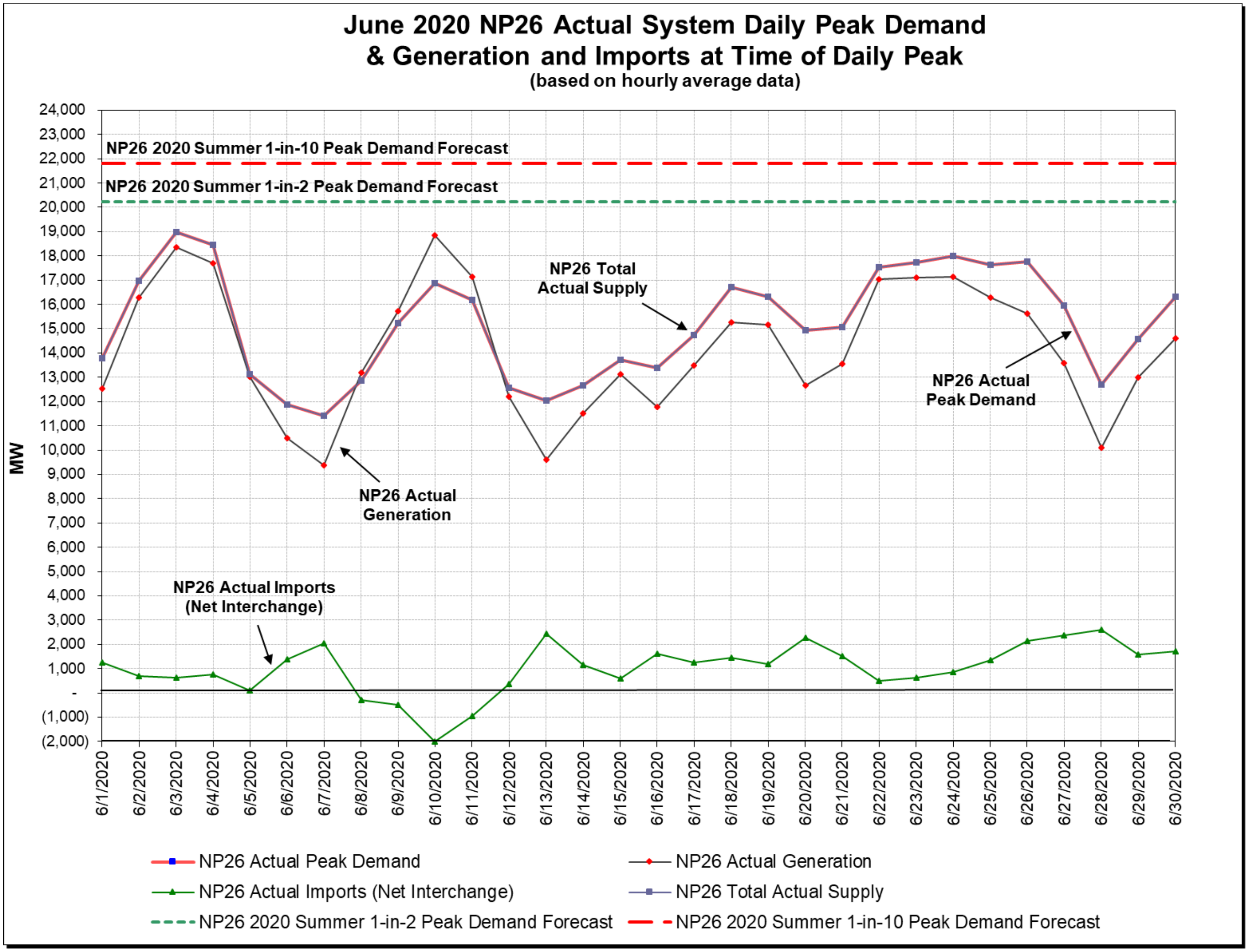
Appendix A: 2020 Summer Supply and Demand Summary Graphs



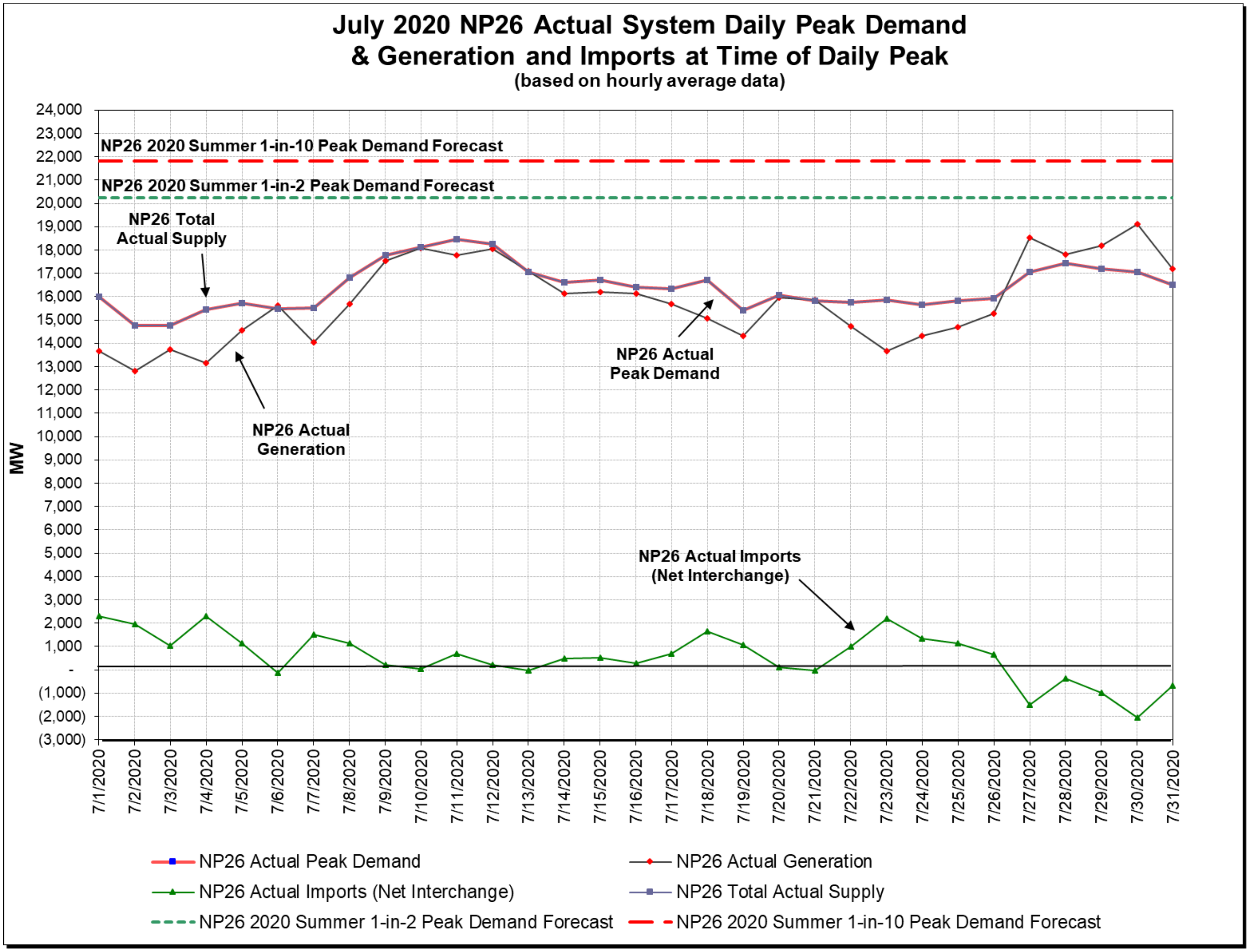
Appendix A: 2020 Summer Supply and Demand Summary Graphs



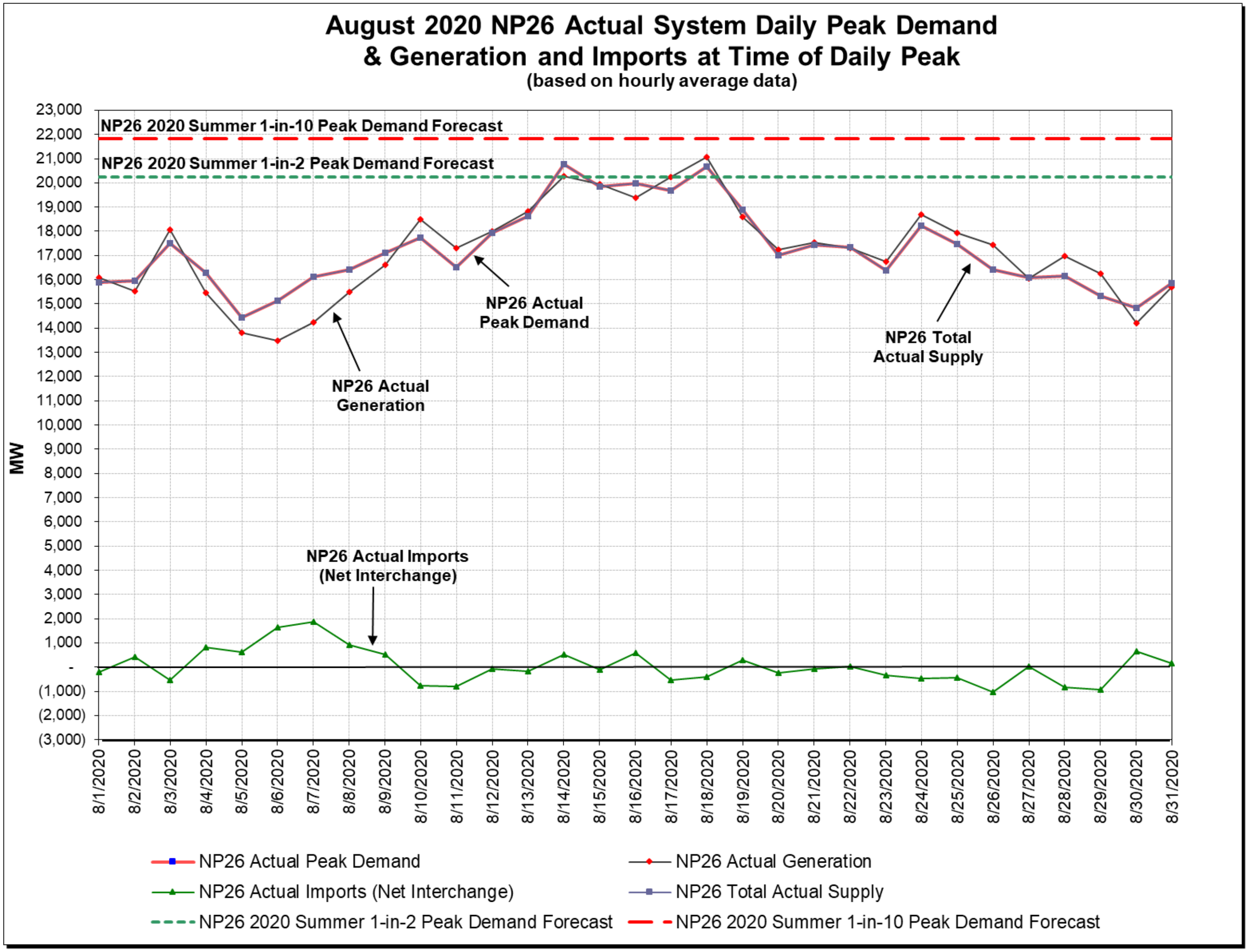
Appendix A: 2020 Summer Supply and Demand Summary Graphs



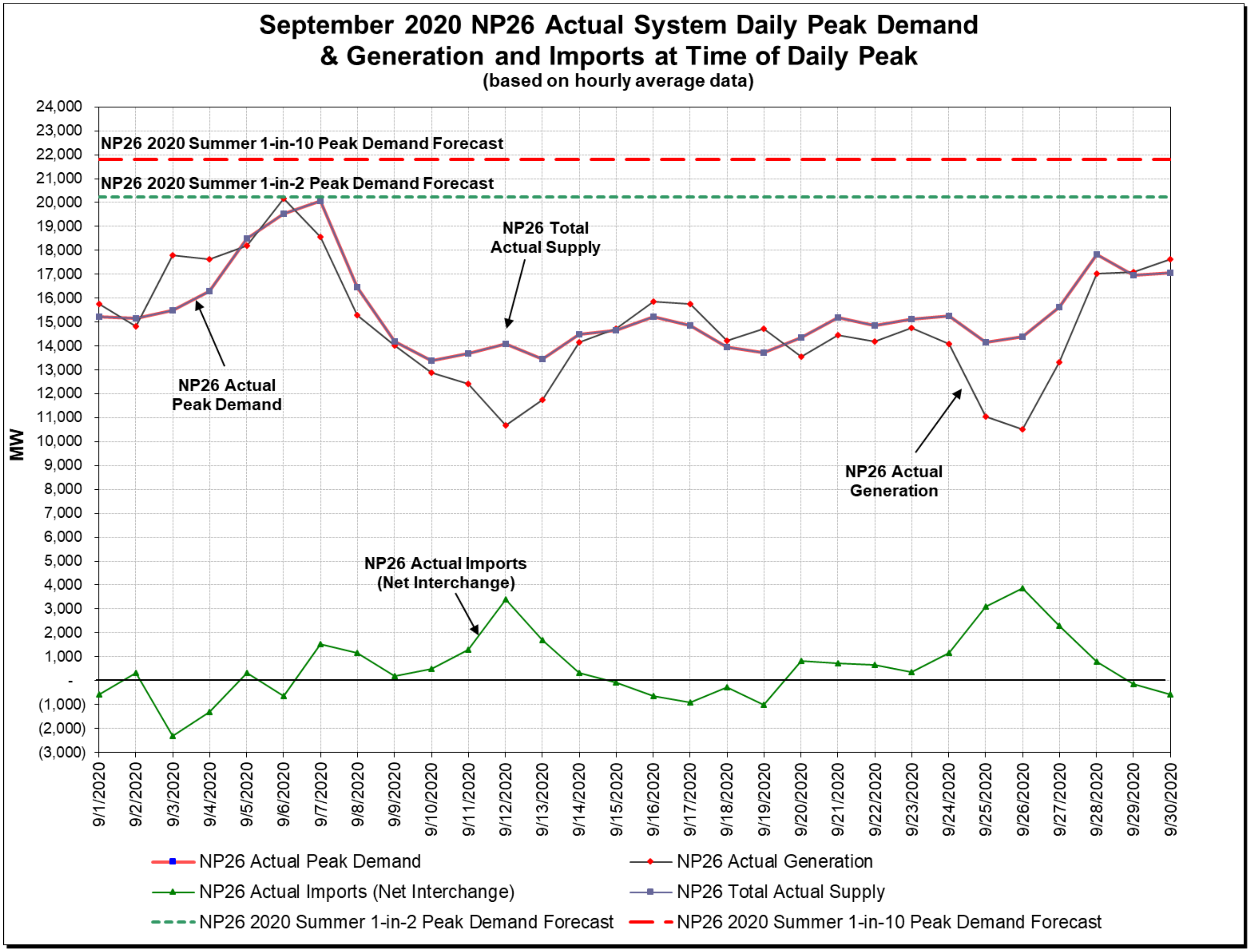
Appendix A: 2020 Summer Supply and Demand Summary Graphs



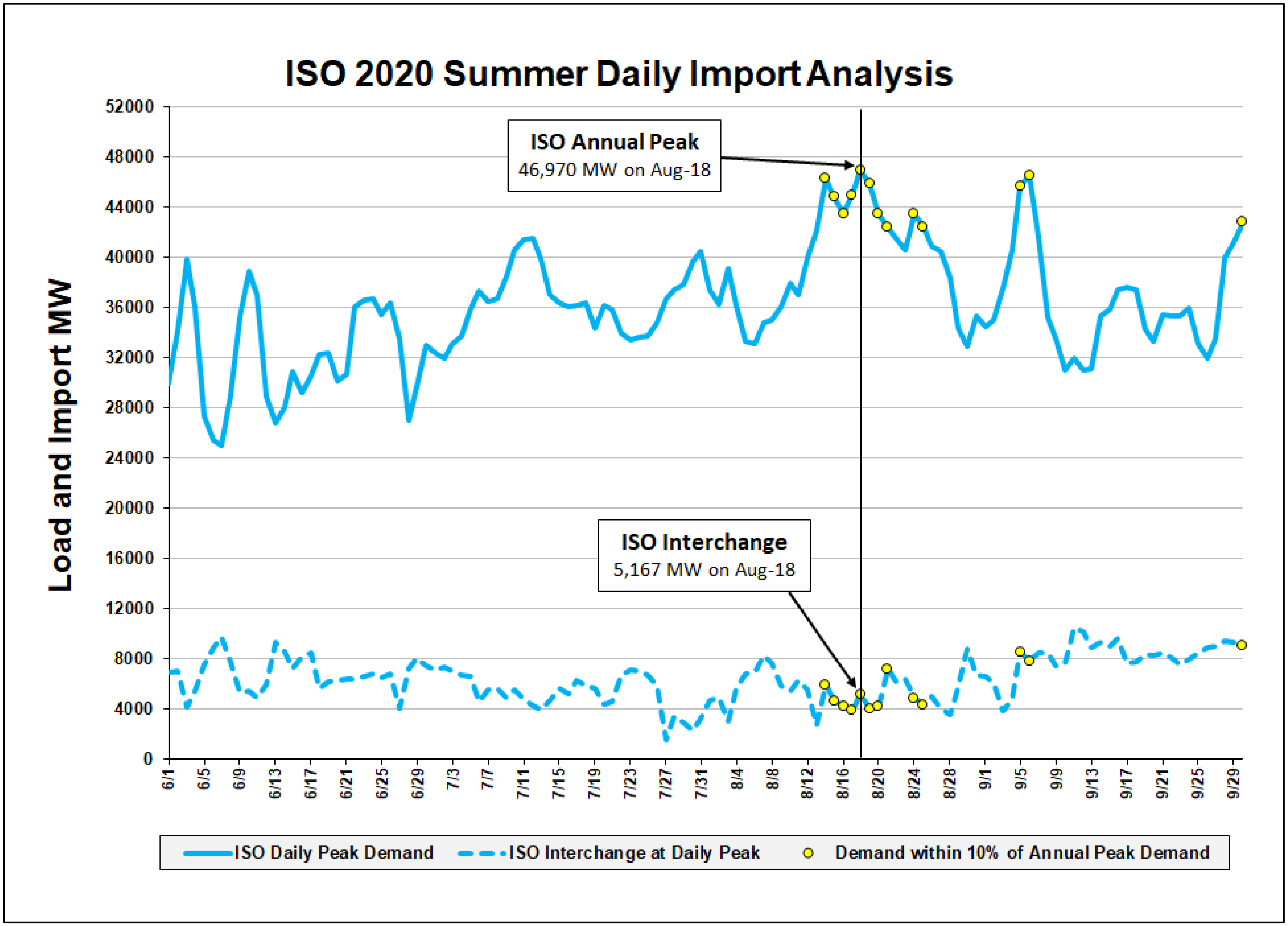
Appendix A: 2020 Summer Supply and Demand Summary Graphs



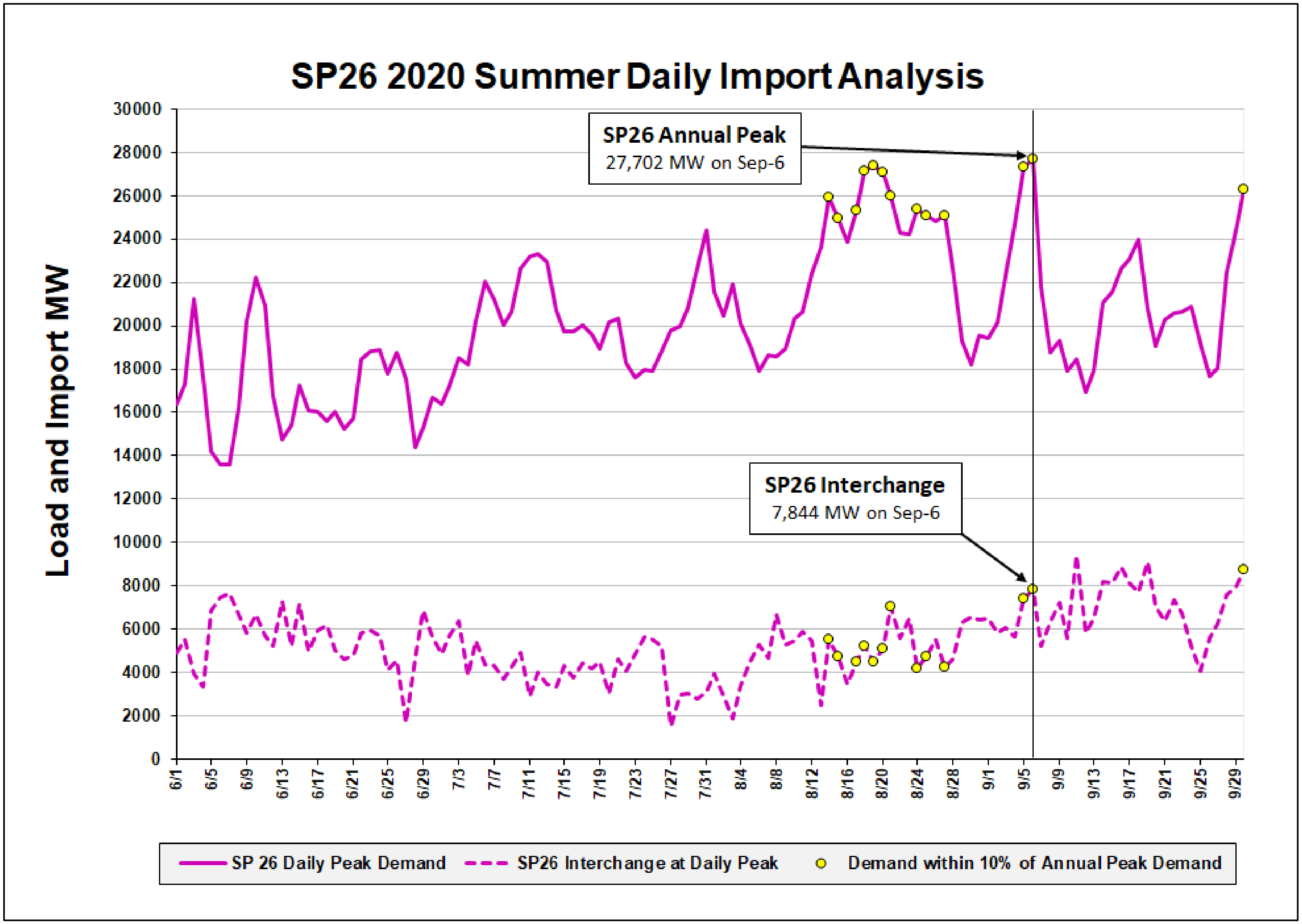
Appendix A: 2020 Summer Supply and Demand Summary Graphs



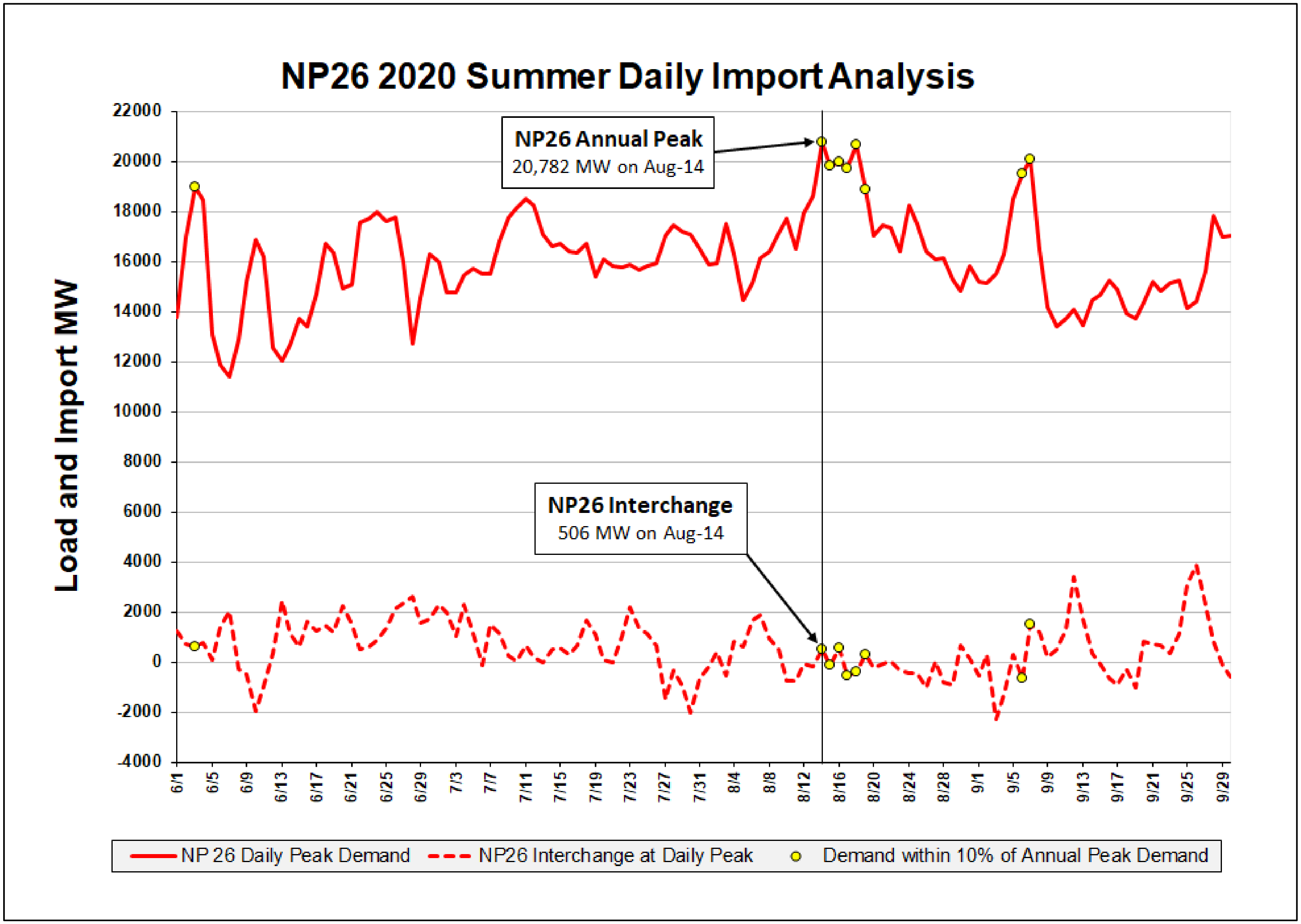
Appendix B: 2020 Summer Imports Summary Graphs



Appendix B: 2020 Summer Imports Summary Graphs



Appendix B: 2020 Summer Imports Summary Graphs



Appendix C: 2021 ISO Summer Maximum On-Peak Available Capacity by Fuel Type