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Witness: Brian D. Theaker
Administrative Law Judge Brian Stevens

PREPARED TESTIMONY OF BRIAN D. THEAKER ON BEHALF OF MIDDLE RIVER POWER LLC

September 1, 2021

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PREPARED TESTIMONY OF BRIAN D. THEAKER

Introduction

Q. PLEASE STATE YOUR NAME.

A. My name is Brian D. Theaker.

Q. BY WHOM AND IN WHAT CAPACITY ARE YOU EMPLOYED?

A. I am Vice President Western Market and Regulatory Affairs for Middle River Power LLC ("MRP").

Q. PLEASE SUMMARIZE YOUR EDUCATION AND EXPERIENCE.

A. I obtained a Bachelor of Science in Electric Engineering degree from the Ohio State University in 1983 and a Master's in Business Administration degree from Pepperdine University in 1989. I worked for the Los Angeles Department of Water and Power in special field test and operating engineering from June 1983 to September 1997. I worked for the California Independent System Operator ("CAISO") from September 1997 until January 2005 in various capacities, including in operations engineering, contract management, and regulatory affairs. After leaving the CAISO, I handled California state and federal regulatory affairs for Williams Power from January 2005 through November 2007, for Dynegy from December 2007 through March 2011, for NRG Energy from March 2011 through August 2019, and for MRP from September 2019 to the present. I also was a member of the Board of Directors for the Western Electricity Coordinating Council (WECC) from 2008 to 2013, and I have served on WECC's Member Advisory Committee from 2013 to the present.

Q. FOR WHOM ARE YOU TESTIFYING?

A. I am testifying on behalf of MRP.

Q. HAVE YOU TESTIFIED BEFORE REGULATORY BODIES BEFORE?

A. Yes. I testified on behalf of the CAISO before the Federal Energy Regulatory Commission on Reliability Must-Run contract matters in 2000. I also submitted testimony to this Commission in Rulemaking 12-03-014 in 2013 and in consolidated Applications 14-06-021 and 14-12-17 in 2019.

Q. WHAT IS THE PURPOSE OF YOUR TESTIMONY IN THIS PROCEEDING?

A. The purpose of my testimony is to submit two proposals in response to the August 10, 2021 *Assigned Commissioner's Amended Scoping Memo and Ruling for Phase 2* ("August 10 Phase 2 Ruling"). In addition, Administrative Law Judge Brian Stevens' August 11, 2021 *E-mail Ruling Providing Staff Guidance on the Content of all Program Proposals Submitted in Opening Testimony by Parties to This Proceeding* ("August 11 E-Mail Ruling") asked parties to "…identify any new policy or modification to an existing policy that could reduce demand or increase supply at [the time of] net peak [demand]". My testimony will set forth proposals that will help ensure the availability of resources assumed in the reliability analyses to be available, and, in light of the need to retain existing resources, reduce emissions from those needed resources. My testimony will also respond to staff proposals contained in the August 16, 2021 *Energy Division Concept Paper Proposals for Summer 2022 and Summer 2023 Reliability Enhancements* ("Staff Concept Paper").

Q. PLEASE SUMMARIZE YOUR TESTIMONY.

A. *First,* I will discuss the preliminary stack analysis ("PSA") conducted by the California Energy Commission ("CEC"), especially the PSA's assumption that all existing resources will remain in operation and committed to serving California load in 2022. Given recent developments, I will discuss why this assumption is flawed.

Second, I will propose that the Commission implement multi-year forward system RA requirements as soon as possible. I will also propose two other actions the

Commission should take now in response to the PSA – accelerating the D.21-06-035 buildout and setting a net load peak RA requirement.

Third, I will discuss how recent analyses project the future need for gas-fired generation.

Fourth, I will discuss how procurement focused at addressing the net load peak hour deficiencies identified in the preliminary stack analysis could, if assessed through the existing RA program, have the unintended consequence of displacing existing generation – something the proposed net load peak requirement is intended to help avoid.

Fifth, I will propose that the Commission direct the hybridization of existing gas peaking units with short (i.e., less than four-hour) duration Battery Energy Storage Systems (BESSs). This action will help maintain reliability, reduce the emissions associated with retaining the thermal fleet for the foreseeable future and reduce the curtailment of solar and wind resources.

Sixth, on behalf of MRP, I will respond to various conceptual proposals presented in Section C of the August 16, 2021 *Energy Division Staff Concept Paper Proposals for Summer 2022 and 2023 Reliability Enhancements* ("Staff Concept Paper").

Finally, in accordance with Administrative Law Judge Brian Stevens' August 12, 2021 *E-mail Ruling Providing Information Notice Regarding the California Energy Commission's Draft Preliminary 2022 Summer Supply Stack Analysis*, I am appending to my testimony the comments that MRP submitted to the California Energy Commission on August 20, 2021 on the preliminary stack analysis.

Topic 1 – The Preliminary Stack Analysis

Q. PLEASE PROVIDE YOUR UNDERSTANDING OF THE CEC'S PRELIMINARY STACK ANALYSIS.

A. The CEC's preliminary stack analysis (PSA) projects that, during net load peak hours (Hours Ending (HE) 16-21) in July, August and September 2022, grid resources are not sufficient to meet operating requirements that are based on forecast demand plus a Planning Reserve Margin ("PRM"). Specifically, the PSA projects a deficiency of 5,274 MWs for September 2022 during HE 20 using a 22.5% PRM. Similarly, the PSA projects deficiencies for some net load peak hours in July and August using a 22.5% PRM. The PSA also projects deficiencies for net load peak hours in September using a 15% PRM.

The PRM provides operating margin (i.e., additional capacity above forecast demand) for three purposes: *first,* to provide operating reserves; *second,* to account for resource forced outage rates; and *third*, to account for demand forecast variability/error. The PSA expressly notes that the 15% PRM includes 6% for operating reserves, 7.5% for forced outages and 1.5% for demand forecast variability, while the 22.5% PRM also includes an additional 7.5% for demand variability, which the PSA represents is for a greater than 1-in-10 weather event.

I note that the PSA shows solar on an energy basis but shows all other resources on a capacity basis. While this helps reinforce the reality that solar is not available to serve demand after the sun goes down, it conflates capacity and energy measurements. For example, wind, and, to a lesser extent, hydro, are variable resources like solar, but the existing resource column, which includes wind and hydro, shows the same value across all hours. This mixing of energy and capacity bases, along with the lack of any numerical information, makes it difficult to fully understand all the underlying assumptions.

While the PSA projects amounts of capacity needed to address projected deficiencies, the PSA does not identify whether curing the procurement deficiencies will achieve a 0.1 loss of load expectation ("LOLE"), or a higher or lower LOLE. Given that the Commission must balance reliability, decarbonization and cost, it would seem axiomatic that the Commission should not direct procurement beyond that needed to simultaneously achieve RA, operating and decarbonization requirements and a 0.1 LOLE.

Q. WHAT DOES THE PSA SAY ABOUT EXISTING RESOURCES?

A. Though the PSA does not expressly state it, I conclude that the PSA assumes that all existing generation is both (1) retained (*i.e.* remains in operation) and (2) available to serve California demand. I base that conclusion on these things. *First*, the only adjustment to existing resources is described as a "drought adjustment", which, presumably, is only to the hydro resources. *Second*, the proposed shortfalls in HE 18-21 in September, which are sizeable (between 1,165 MW and 5,274 MW depending on the PRM used) would be even greater if the PSA did not assume that ALL resources are retained; given the costs of over-procurement, it seems reasonable to assume that the Commission would not direct procurement that was not needed, which leads to the conclusion that all existing resources are retained. *Finally*, I note that assuming all existing thermal generation remains available to and committed to serving California load over the near- to mid-term is a common assumption for California-focused reliability analyses. While I will call that assumption into question below, all these things lead me to the conclusion that the PSA assumes that all existing generation – thermal and otherwise – remains in operation and committed to serving California load.

Q. WHY IS THE ASSUMPTION THAT ALL EXISTING CAPACITY WILL REMAIN IN OPERATION AND COMMITTED TO SERVING CALIFORNIA LOAD FLAWED?

A. In 2021, MRP has been approached by load serving entities (LSEs) outside California regarding MRP entering into multi-year contracts for its in-California generating resources to serve as supporting resources for exports from the CAISO Balancing Authority Area ("BAA") to the LSEs' BAA. Under current Resource Adequacy ("RA") program rules, local capacity requirements apply for three years forward, but system RA requirements apply for, at most, one-year forward. Nothing prevents LSEs from entering into multi-year contracts for system RA capacity, but nothing compels LSEs to enter into multi-year system RA contracts, either. Under current RA program design, therefore, existing generators can only expect to contract for a single year forward at a time. Given that the owners of generating resources within California that can provide system and flexible RA capacity but not local capacity would prefer to have more, rather than less, certainty about forward revenue streams for their resources, it is reasonable to expect that owners of in-state generating resources will find these multi-year arrangements with external LSEs attractive. I therefore propose that the Commission institute multi-year forward RA requirements for LSEs to retain existing resources to help ensure that any assumptions about existing resources over the near- to mid-term are supported by RA program requirements.

Topic 2 – Multi-Year Forward System RA Requirements

Q. WHAT DO YOU PROPOSE WITH REGARDS TO MULTI-YEAR FORWARD SYSTEM RA REQUIREMENTS?

A. I propose that the Commission implement multi-year forward system Resource Adequacy requirements in 2022 for the subsequent RA compliance years. If existing capacity does not remain both in operation and committed to serving California load over the near- to mid-term, any new procurement over this term will simply displace existing capacity that is not retained and will not "increase supply". So, while my proposal would not "increase supply" *per se*, it is critical to adopt it to ensure that existing generation remains in operation and committed to California load so that new procurement can address projected supply shortfalls and not simply "backfill" the loss of existing resources either to retirement or to serving load outside California.

Retaining existing generation will provide benefits beyond operationalizing the assumption that all in-state capacity will remain in operation and committed to serving California load for the near-term to mid-term. I note that, while the Commission has directed 16.3 GW of procurement over the last two years – 3.3 GW in D.19-11-016, 1.5 GW in D.21-03-056, and 11.5 GW in D.21-06-035 – the cost of this new procurement has neither been estimated or publicly presented. As the 2019 Energy and Environmental Economics ("E3") Long-Run Resource Adequacy Analysis concluded, retaining existing duration-unlimited thermal generation is a far more cost-effective way to maintain reliability than replacing that existing generation with much greater nameplate capacity amounts of use- and duration-limited generation.[1]

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[1] *See* Energy and Environmental Economics June 2019 *Long-Run Resource Adequacy Under Deep Decarbonization Pathways for California* ("E3 Long-Run Resource Adequacy Analysis"), at p. 42,

Q. WHAT LENGTH OF MULTI-YEAR REQUIREMENTS DO YOU PROPOSE?

A. The longer the forward requirement, the greater the forward certainty for suppliers and the longer the generating units remains committed to serving California load, to the benefit of in-state LSEs. While the Commission adopted three-year forward local capacity requirements in D.19-02-022, given that the draft Preferred System Plan ("PSP") projects no gas retirement through 2032,[2] five-year system requirements could be better for the mid- to near-term. Considering both facts, I recommend that the Commission implement three- to five-year forward system requirements.

Q. WHAT MULTI-YEAR PROCUREMENT TARGETS DO YOU RECOMMEND?

A. I recommend that the procurement targets be set as high percentages of the annual system capacity requirements, specifically, at 100% of the requirements for the first two years and at least 80% for the succeeding years of whatever term is chosen. The purpose of these multi-year forward requirements is to ensure sufficient generation remains in operation and committed to California over the near- to mid-term. If the requirements are not set properly, then multi-year forward requirements will not retain the resources that they are intended to retain.

Q. WHEN SHOULD THESE MULTI-YEAR REQUIREMENTS TAKE EFFECT?

A. In 2022 for the succeeding RA years. Waiting increases the risk that in-state resources that will roll-off single-year contracts will enter into multi-year contracts with out-of-state LSEs.

Figure 25. This report is available at https://www.ethree.com/wp-content/uploads/2019/06/E3_Long_Run_Resource_Adequacy_CA_Deep-Decarbonization_Final.pdf).

[2] *See* Administrative Law Judge Julie Fitch's *Administrative Law Judge's Ruling Seeking Comments on Proposed Preferred System Plan* ("ALJ PSP Ruling"), issued on August 17, 2021 in Rulemaking 20-05-003, at Figure 9, p. 27 (indicating that neither the 38 MMT Core Portfolio nor the 30 MMT High Electrification portfolio retired any gas capacity).

Q WHAT OTHER BENEFITS DO MULTI-YEAR SYSTEM RA CONTRACTS OFFER?

A. Several. *First,* multi-year RA contracts smooth out needed maintenance costs. Thermal generating resources must take periodic major maintenance based on a unit's operating history. The cost of major maintenance can be substantial relative to a unit's other fixed operating costs. Recovering those costs in a single-year RA contract can push the price of that one-year contract to a level that may give LSEs or the Commission pause. Conversely, being able to spread that major maintenance cost across multiple years avoids spiking contract prices to recover those costs in a single year.

Second, the additional forward certainty provided by multi-year RA contracts lowers a resource's risk. Lowering risk reduces the resource's cost of capital by providing cash flow and yield certainty, improving the asset's credit profile and reducing both the cost of debt and cost of equity for the asset investment. In contrast, single-year RA or RMR contracts provide little certainty and increase a unit's risk profile and, correspondingly, its cost of capital. Said another way, if California is going to need thermal resources for some time to come (as the analyses cited above indicate), it would be more cost-effective for California ratepayers to retain those units through multi-year arrangements than through a series of repeating single-year contracts.

Q. WILL MULTI-YEAR REQUIREMENTS RESULT IN THERMAL GENERATION OPERATING LONGER THAN NECESSARY?

A. No, establishing multi-year RA requirements in 2022 will not result in thermal generation operating more, or longer, than necessary. Numerous analyses, including those referenced in this testimony, have shown that the grid needs the entire thermal fleet along with all other existing resources in 2022 and beyond to ensure reliability. Moreover, concerns about keeping thermal generation around longer than needed are misplaced.

Retaining thermal generation in no way threatens California's ability to progress towards its decarbonization goals. As California adds additional zero-emitting resources, the energy from these resources will displace the energy from thermal generation, and thermal generation will run less, producing fewer emissions.

I note that the Commission could address concerns about "unneeded" thermal energy by directing its jurisdictional LSEs to enter into tolling agreements with thermal resources. This would allow the LSEs to bid these resources into the CAISO's markets either at cost-based prices (to minimize cost) or in a manner that would limit energy production (to minimize emissions). At the same time, the duration-unlimited thermal generation would remain available as needed to maintain reliability.

Q. SHOULD THE COMMISSION TAKE ANY OTHER ACTIONS?

A. Yes. Rather than ordering *additional* procurement to cure the deficiencies projected in the PSA, the Commission should seek to expedite the procurement of the 11.5 GW ordered in D.21-06-035 to meet the deficiencies projected by the CEC. I base that proposal on the following observations.

The ALJ PSP Ruling proposes to adopt as the PSP the "38 million metric ton core portfolio".[3] The ALJ PSP Ruling indicates that this portfolio includes the 11,500 MW of procurement ordered in Decision (D.) 21-06-035.[4] Importantly, the ALJ PSP Ruling presents the results of Strategic Energy & Risk Valuation Model ("SERVM") analysis that indicates this portfolio achieves a LOLEs that are lower than the 0.1 LOLE planning standard – 0.064 in 2026 and 0.054 in 2030.[5]

[3] ALJ PSP Ruling at p. 21.
[4] *Id*. at p. 13.
[5] *Id*. at p. 20.

I note that the Mid-Term Reliability analysis recently presented by CEC staff indicates that PSP procurement ratioed out from 2022 to 2026 would result in a 2022 LOLE of 0.194, and it would be necessary to add 1,296 MW of capacity to achieve a 0.1 LOLE in 2022.[6] The fact that only 1,296 MW of capacity is required in 2022 in addition to the "PSP ratio" procurement suggests that procuring 5,274 MW of capacity to address the PSA's maximum projected net load peak deficiency in 2022 will drive the 2022 LOLE well below 0.1 and is unnecessary.

Given that the 11.5 GW of procurement directed in D.21-06-035 pushes system reliability beyond what is required, any procurement that the Commission directs to close the deficiencies identified in the PSA should be part of that procurement and not in addition to that procurement. Additional procurement would result in increasing ratepayer costs and paying for reliability beyond what is required. MRP notes that the estimated cost of new procurement associated with the 38 MMT core portfolio is over $900 billion with an incremental ratepayer impact of 19 cents/kWh.[7] If the Commission orders additional procurement above what has already been projected, it would significantly increase the costs that would be borne by ratepayers for greater reliability than the planning standards require.

I also note that the 11.5 GW procurement directed in D.21-06-035 is net qualifying capacity ("NQC") based on marginal ELCC methodologies.[8] Given that the Integrated Resource Planning process has adopted a marginal ELCC methodology, but the RA program has not yet adopted a marginal ELCC methodology, I am concerned that

[6] *See* presentation for the August 30, 2021 *Lead Commissioner Workshop – Midterm Reliability Analysis & Incremental Efficiency Impro0vements to Natural Gas Power Plants* at slide 33.
[7] ALJ PSP Ruling at p. 19.
[8] D.21-06-035at p. 2, Ordering Paragraph 1.

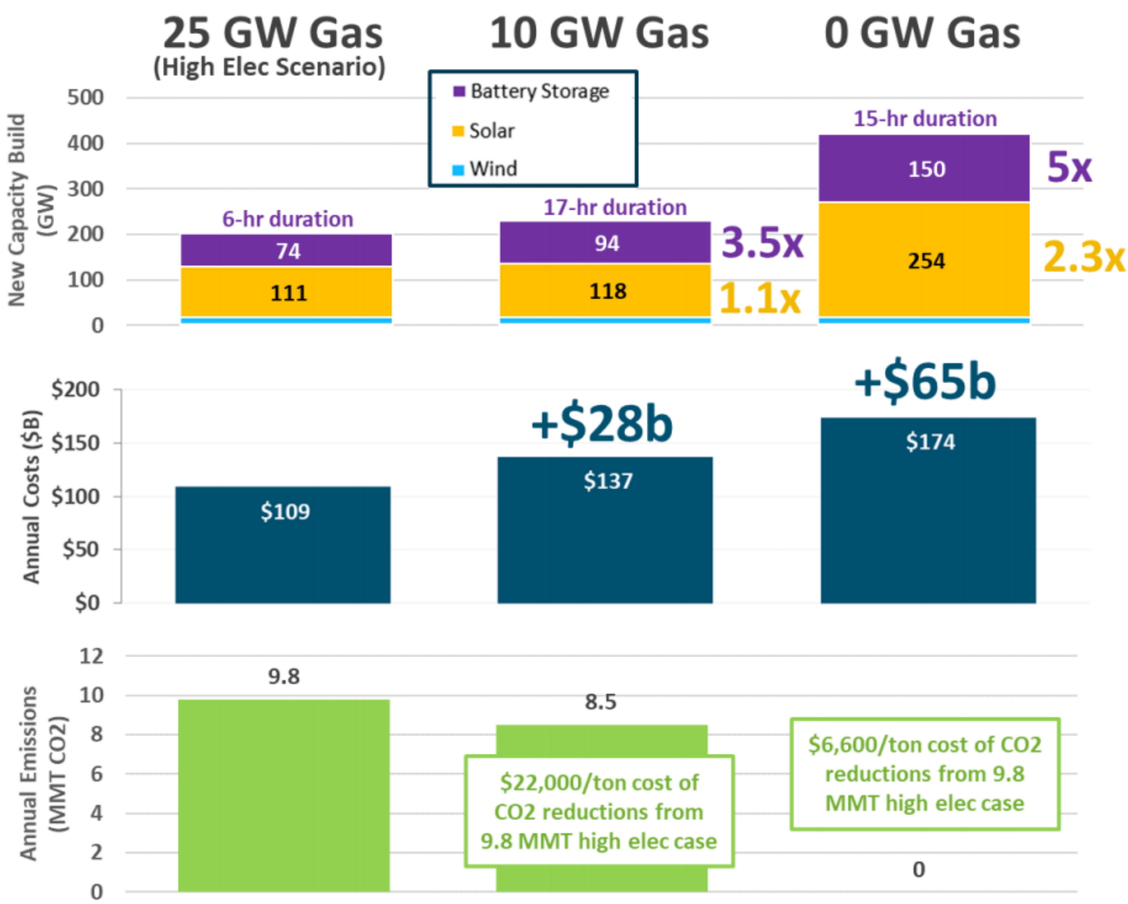
this mismatch may result in these programs applying different definitions to the term "NQC", which could result in an amount of IRP MW being assigned a higher value for RA purposes. In any case, the need identified in the PSA is for capacity across the peak net load hours. Because, under current RA program rules, a resource may qualify to provide NQC even if it provides no contribution to system reliability across the net load peak hours (e.g., solar resources), not every resource that can qualify to meet the D.21-06-035 procurement can also address the deficiencies identified in the PSA. This limitation aside, given that the 38 MMT core portfolio already achieves a LOLE reliability greater than the 0.1 LOLE system planning standard, it should not be necessary to procure 5,274 MW in addition to the 11.5 GW directed in D.21-06-035.

This discussion highlights a mismatch between the way the RA program measures capacity (NQC) and the capacity that the PSA projects is required to address deficiencies (capacity across the net load peak hours). I will discuss MRP's concerns about how this mismatch could affect RA procurement below. While I acknowledge that Track 3B.2 of the RA program is considering ways to address this mismatch, below I will recommend the Commission set and enforce a separate net load peak RA requirement until the Track 3B.2 RA program redesign is implemented.

Topic 3 – The Future Need for Gas-Fired Generation

Q. WHAT IS YOUR TESTIMONY REGARDING THE NEED TO RETAIN THE EXISTING GAS-FIRED GENERATION FLEET?

A. Three analyses conducted since 2019 point to the need to retain most of the existing gas-fired generation fleet for the next few decades. In 2019, the *Long-Run Resource Adequacy Analysis under Deep Decarbonization Pathways for California* study conducted by Energy and Environmental Economics ("E3") showed that the most cost-effective way for California to achieve the SB 100 decarbonization goals while maintaining reliability was to retain 17-35 GW of natural gas generation capacity.[9] What may be the most recognizable graph from that report, which shows the effects of forced retirements of gas-fired generation, is shown below:[10]



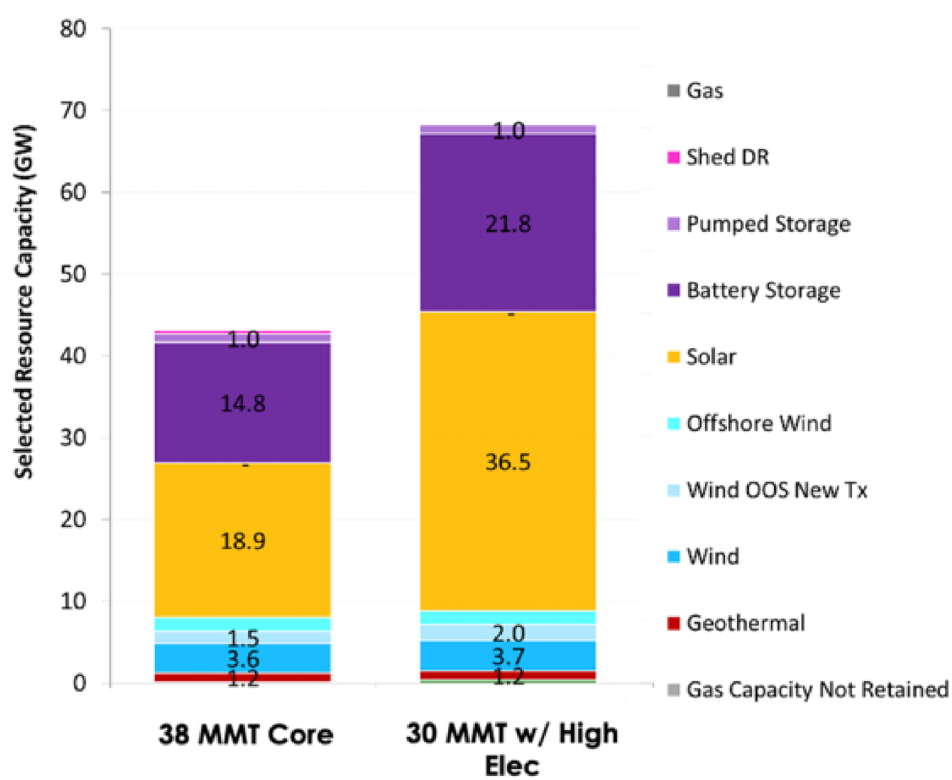
As I noted above, this figure indicates that the most cost-effective way to achieve the SB 100 decarbonization goals is to retain most, if not all, of the existing gas fleet.

The *2021 SB 100 Joint Agency Report* released earlier this year arrives at a very similar conclusion. According to this report, the “SB 100 Core” scenario retires only 4.7

[9] E3 Long-Run Resource Adequacy Analysis, pp iii, 58.
[10] *Id.*, Figure 25, p. 42.

GW of gas capacity and the "expanded load coverage" study scenario retires only 7.2 GW of gas capacity.[11]

Most recently, the draft PSP released in the Commission's Integrated Resource Planning proceeding projects that, by 2032, *no* existing gas capacity is retired in either the 38 MMT Core Portfolio case *or* the 30 MMT High Electrification case, as shown in Figure 9 from the ALJ Ruling accompanying the draft PSP:[12]



These three analyses reach a common conclusion, namely, that the least-cost way to maintain reliability over at least the next decade, and even out to 2045, while still

[11] SB 100 Joint Agency Report at pages 75-76. This report is available at https://efiling.energy.ca.gov/EFiling/GetFile.aspx?tn=237167&DocumentContentId=70349.
[12] The ALJ Ruling and Presentation materials are available at https://docs.cpuc.ca.gov/PublishedDocs/Efile/G000/M399/K450/399450008.PDF.

progressing towards California decarbonization goals, is to retain most (in the long term) or all (in the near- to mid-term) of the existing gas-fired generation fleet.

Q. WHY IS THE NEED TO RETAIN THE EXISTING GAS FLEET RELEVANT TO THIS PHASE OF THIS RULEMAKING?

A. It is relevant because, as noted above, it appears that the PSA assumes that all existing resources, including gas-fired resources, remain in operation and committed to serving California load in 2022. It is also relevant to this phase of the rulemaking because there currently is no mechanism in place to ensure this assumption is realized. If the Commission cannot ensure that all existing generation capacity is retained and committed to serving California load, any "incremental" procurement it orders intending to address projected net load peak deficiencies will go in part to backfilling the loss of these existing resources and will not count towards addressing any deficiencies.

Topic 4 – The Possible Detrimental Collateral Impacts of Procuring Resources to Meet the Net Load Peak

Q. PLEASE DESCRIBE MRP'S CONCERNS ABOUT THE PROCUREMENT CONTEMPLATED FOR THE NET LOAD PEAK.

A. MRP is concerned that procurement focused on the net load peak hours may have unintended detrimental impacts. Currently, the Commission's Resource Adequacy ("RA") program looks only at the gross peak load to set requirements and assess adequacy. If the Commission directs procurement of additional resources to meet the net load peak demand, as it indicates it intends to do in this phase of this rulemaking, such incremental resources are also likely to count towards meeting the gross load peak RA requirements. This will lead to a surplus of resources needed to meet the gross load peak RA requirements and create the perception that a surplus of capacity exists and not every existing resource is still required, even though the PSA appears to indicate that *all* existing resources are required. If existing resources are not retained, this will affect the viability of the PSA and, consequently, the ability to address the projected net load peak deficiencies. The Commission recognized this issue in the Commission Guidance in D.21-03-056, Attachment 1, which states "[g]iven that a portion of the resources that make up LSEs' 15% PRM are solar resources whose generation is declining rapidly at net peak, these procurement targets represent a floor, and IOUs are encouraged to exceed their respective targets by as much as an additional 50%, which would result in approximately 1,500 MW of incremental procurement and an *effective* PRM of 19%."[13] The higher "effective" PRM referred to results from procuring other resources to address the net load peak but then counting those resources, along with solar resources, towards RA requirements which apply to the gross load peak.

To help ensure that net load peak-focused procurement does not displace resources needed to meet gross load peak-focused RA requirements, I propose that the Commission set separate net load peak RA requirements for LSEs starting in May 2022 and ending when the RA Track 3B.2 proceeding implements the Slice of Day framework. The net load peak requirements would be similar to the current gross load peak requirements but could not be met by solar resources.[14] This net load peak RA requirement would also include either the extreme weather (22.5%) PRM, or a PRM

[13] D.21-03-056 at Attachment 1, p. 20 (emphasis added).
[14] The traditional definition of net load peak is gross load net of wind and solar generation. However, for the purposes of the proposed net load peak requirement, I propose this definition of net load peak because the CEC's PSA effectively projected a deficiency due to the lack of solar resource contribution but apparently accounted for wind resource capacity in the supply stack. If the Commission prefers the more traditional definition, then wind resources also would not be allowed to meet the net load peak requirement.

found to be reasonable by the Commission based on record evidence. If LSEs cannot meet this net peak RA requirement, then the current RA penalty structure would apply.

I acknowledge that the topic of modifying the RA program to consider the net load peak is currently underway in Track 3B.2 of Rulemaking R.19-11-009. However, given the schedule for Track 3B.2, the RA program may not be redesigned by the time additional procurement is directed in this rulemaking. Further, establishing a net load peak RA requirement in this proceeding would not prejudge the outcome of the RA Track 3B.2 proceeding.

Topic 5 – Hybridization

Q. WHAT IS YOUR PROPOSAL REGARDING HYBRIDIZATION?

A. I also propose that the Commission direct LSEs enter into contracts with simple-cycle gas peaking capacity to add short-duration (i.e., less than four-hour) batteries equal to the capacity of the gas peaking units.

Q. WHY SHOULD THE COMMISSION DIRECT HYBRIDIZATION OF GAS PEAKER PLANTS?

A. Hybridization of simple cycle gas peaking units offers several benefits. *First,* MRP believes that hybridization will dramatically reduce emissions associated with the current dispatch of simple cycle peaking units. In MRP's experience, nearly half of energy dispatches associated with peaking units are for one hour or less duration. If BESSs were installed at these sites, the BESS could be dispatched first and the gas turbines turned on only if it was necessary to sustain a response for longer than the duration of the battery. Additionally, the short-duration BESS can also reduce the need to dispatch other fossil resources during other times of the year when the peaking units generally do not run, thereby further reducing emissions from other fossil resources. Inasmuch as the BESS will be charged with grid power and not from the gas peaking units on site, MRP expects that this would result in a significant reduction in emissions, which would not only provide system benefits but would also provide even greater benefits to local communities, which could include disadvantaged communities. Based on its analysis, MRP expects that these BESSs would likely be charged during the middle of the day, during the high solar hours, when solar production is at its peak and, on a per-MW system wide basis, carbon emissions are at their lowest. Analysis that was based on MRP's experience at one of its peaking unit sites showed hybridizing with short, one-hour duration batteries would cut emissions by 70%.

Second, because the BESSs would be sized at the MW capability of the existing peaking resource(s), and further given that the BESSs and the peaking resources would not be operating simultaneously, the interconnection capacity at these sites would not need to be increased. Given the delays associated with CAISO's Interconnection Queue Cluster 14, and the challenges associated with securing additional deliverability throughout the CAISO system in the near term, projects that require additional interconnection capability and deliverability are likely to be challenged to achieve a COD prior to 2025 or 2026.

In sum, given the expectation that most of the gas-fired generation fleet will need to remain in operation for the foreseeable future, hybridizing gas peaking units with short-duration BESSs reduces emissions and decarbonizes the electrical generation fleet, but also preserves the duration-unlimited gas-fired peaking units for dispatch across multiple hours as needed for reliability. These hybrids could be configured to respond with the BESS first so that the thermal resource is operated only when required. Without the need for additional interconnection capacity, such projects would not have to partake in the CAISO's extended "Supercluster" 14 process.

Q. DOES MRP PROPOSE HOW MANY MW OF PEAKING TURBINES SHOULD BE HYBRIDIZED?

A. MRP estimates that there are approximately eight (8) GW of gas peaking turbines currently operating within the CAISO's footprint. Given that recent analyses expect most, if not all, of the existing gas capacity to be retained for the foreseeable future, MRP suggests the Commission consider directing hybridization for at least half of these sites.

Q. WHAT OTHER ARRANGEMENTS DO YOU PROPOSE?

A. Given that the benefits of hybridization depend on having both the duration-unlimited gas peaking unit and the short-duration BESS operating in concert, the gas peaking units at the hybridized sites should be contracted for the same term as the BESS system.

Q. FOR WHAT FUTURE TIME FRAME SHOULD THE COMMISSION REQUIRE HYBRIDIZATION?

A. Given current lead times for procuring BESSs, I recommend that the Commission target hybridization for 2024.

Topic 6 – Responses to Selected Proposals in the Staff Concept Paper

Q. SHOULD THE COMMISSION INCREASE RESOURCE ADEQUACY PENALTIES AS PROPOSED IN SECTION C.2?

A. D.20-06-031 increased the penalty for system RA deficiencies from $6.66/kW-month for all 12 months to a shaped rate of $8.88 in May through October and $4.44/kW-month in November-April.[15] Pursuant to D.21-06-029, deficient LSEs would also accrue points which would double or triple the RA penalty price depending the number of months in

[15] D.20-06-031 at Ordering Paragraph 20.

which the LSE is deficient within a 24 month period.[16] Deficient LSEs could also bear the costs of any CAISO Capacity Procurement Mechanism ("CPM") backstop procurement undertaken to cure the deficiency, though the CAISO's record of using CPM to cure REA deficiencies is a mixed record.

MRP supports Staff's proposal with respect to ensuring sufficient existing resources are procured. MRP understands that if LSEs must depend on procuring a combination of existing and new resources to meet the RA requirements, the LSEs should not be penalized if a developer is unable to bring new resources online given the challenging conditions that developers have faced over the last two years.

System RA penalties were increased in 2020, and the "point" system was implemented starting in 2021. Consequently, there is a rather thin record on which to determine whether RA penalties should be increased again. Conversely, however, MRP personnel have had conversations with some LSEs in which the LSEs suggested they would rather be deficient and pay the RA penalties than pay going market rates for system RA capacity. Such conversations suggest that the current penalty rates for RA deficiencies may not be sufficient. Therefore, MRP supports considering increasing the system RA penalty price to ensure existing capacity is procured to ensure reliability.

Q. SHOULD THE COMMISSION ACCELERATE PROCUREMENT ORDERED IN THE IRP MID-TERM RELIABLILTY DECISIONS AS PROPOSED IN SECTION C.3?

A. Yes. As discussed above, MRP believes accelerating the 11.5 GW of mid-term reliability procurement directed in D.21-06-035, rather than directing additional new procurement, is the best approach to addressing near-term deficiencies while ensuring that LSEs do not

[16] D.21-06-029 at Ordering Paragraph 16.

over-procure capacity. The IRP PSP 38 MMT core portfolio includes the 11.5GW mid-term reliability procurement[17] and achieves a LOLE that is less than 0.1 LOLE planning standard.[18] Therefore, accelerating procurement already ordered rather than ordering *new* procurement is better approach.

Q. WHAT COMMENTS DO YOU HAVE ON THE PROCUREMENT PROPOSED IN SUBSECTIONS C.4 (a) THROUGH (i)?

A. MRP has concerns with many of the proposals advanced in this section and will discuss each subsection individually.

Subsection C.4 (a). Staff proposes that resources that could achieve accelerated online dates in advance of system RA requirements or otherwise applicable IRP Procurement Orders should be eligible for a new non-bypassable charge ("NBC"). These resources would have to be subject to a must offer obligation and be in excess of any single LSE's individual RA requirement. While MRP does not take a position on the NBC, MRP would appreciate if Staff or the Commission can clarify the application of this proposal. *First,* the accelerated procurement ordered in D.19-11-016 and D.21-03-056 seem to be part of the baseline resources of the CEC's stack analysis. Counting these resources as "incremental" procurement for the purposes of closing the deficiencies in the preliminary stack analysis requirement would erode the baseline of resources assumed in the preliminary stack analysis. *Second,* it is unclear what Staff means by "in excess of any single LSE's individual RA requirement." Is Staff proposing that this NBC be used by *all* LSEs, not just IOUs, to allocate costs among all other LSEs for any procurement greater than their own RA requirements?

[17] ALJ PSP Ruling at p. 14.
[18] *Id*. at p. 20.

Subsection C.4 (b). Staff proposes that IOU procurement could be increased, above that of the need for their own bundled procurement RA obligations and extended also into 2023 or beyond would qualify for the new NBC. MRP notes that neither the Staff proposal nor the CEC analysis indicate the procurement level necessary to maintain reliability (i.e., achieve a 0.1 LOLE) for 2022 or beyond. In contrast, the recently released Preferred System Plan indicates that the 38 MMT Core Portfolio – which consists of the individual Integrated Resource Plans submitted by the LSE plus the 11.5 GW of procurement directed in D.21-06-035, drives the LOLE well below 0.1, to 0.064 in 2026 and to 0.054 in 2030.[19] Increasing procurement beyond that already directed, when that procurement drives the system to a greater reliability than the current design standard, does not seem to be in the best interest of ratepayers.

Subsection C.4 (c) In this section, Staff proposes to allow for new utility-owned storage that could be on-line by summer 2022. Even though IOUs may have site control, IOU projects still face the same interconnection, deliverability, permitting and supply chain issues faced by any other developer.[20] Additionally, the Commission has specifically directed IOUs to propose evaluation metrics to ensure fairness of the utility participation in utility-run solicitations.[21] Before it takes the consequential step of authorizing or ordering additional utility owned generation, the Commission must ensure that utility ownership would be the *only* way to overcome challenges that would be faced by other developers and is in the best economic interest of the ratepayers.

[19] *Administrative Law Judge's Ruling Seeking Comments on Proposed Preferred System Plan,* issued August 17, 2021 in Rulemaking R.20-05-003 at p. 20.
[20] On July 23, 2021, SDG&E submitted to Executive Director Rachel Peterson a notice of delay in development undertaken pursuant to D.19-11-016. PG&E, citing COVID-19 and supply chain issues, filed a similar notice the same day.
[21] D.19-06-032 at Appendix A, Section 2 (c).

Subsection C.4 (d). Staff proposes the deployment of new resources that can be depended on to provide dispatch in response to alerts, warnings and emergencies. Such resources could be use-limited and would not be subject to a must-offer obligation. MRP has many concerns about this proposal. *First,* since these resources would not be required to offer to the CAISO, they ostensibly would be exceptionally dispatched by the CAISO during an alert, warning or emergency, which would unduly impact price formation during these events. *Second*, much more detail is required to understand as to how these resources would be "depended upon" though they were not required to offer and did not count towards RA requirements. *Third,* to the extent they count towards RA requirements, they would provide very limited service and must conform to the RA program MCC bucket caps. In sum, MRP sees great expense, little benefit, and possible harm to energy market price formation coming from this category of proposed new resources.

Subsection C.4 (e). The last time the CAISO used its Capacity Procurement Mechanism (CPM) to prevent a resource from retiring was in 2012 for Calpine Corporation's Sutter Power Plant.[22] Since then, the CAISO has modified its Tariff to use the Reliability Must Run (RMR) process to retain resources at risk of retirement.[23] Staff proposes that these re-contracted resources would have to be in excess of RA requirements. A core issue is

[22] *See* California Independent System Operator Corporation *Petition for Waiver of Tariff Revisions and Request for Confidential Treatment*, filed with the Federal Energy Regulatory Commission on January 25, 2012 in Docket No. ER12-897 (available at http://www.caiso.com/Documents/2012-01-26_ER12-897_Sutter_Pet_TariffWaiver.pdf).

[23] The CAISO no longer uses its CPM authority to prevent resources from retirement. See modifications to CAISO Tariff Sections 41.2 and 43A.2.6 proposed in Tariff Amendment to Improve the Reliability Must-Run Framework, submitted on April 22, 2019 in Federal Energy Regulatory Commission ("FERC") Docket No. ER19-1641 and accepted by FERC in an order issued September 27, 2019 (*California Independent System Operator Corporation*, 168 FERC ¶ 61,199).

that the current RA requirements do not accurately reflect the needs of the grid, specifically the net load peak needs. But because solar resources are counted towards meeting gross load peak RA requirements, procuring additional non-solar resources to meet net load peak requirements will cause existing resources to be in excess of RA requirements, even if all existing resources are required to meet projected net peak demands. Again, above I proposed the Commission establish a net load peak RA requirement that will be met by resources excluding solar generation. This can help ensure that there are no resources that will be determined to be “in excess” of RA requirements.

Subsection C.4 (f). Staff proposes to allow firm imports “above RA limits”. *First,* it is not clear what Staff means by “RA limits”. Import procurement must satisfy several factors, including securing Maximum Import Capability (“MIC”), but it is not clear what “RA limit” applies here. *Second,* it appears to MRP that this proposal seeks to create a new reliability requirement (additional imports) beyond the RA program requirements rather than modifying the RA program to meet the reliability needs. If so, MRP respectfully urges the Commission to modify RA program needs to maintain reliability rather than creating extra-RA programs to do so. *Third,* MRP cautions the Commission about undue reliance on out-of-state resources whose energy must be delivered to California on long-haul transmission. On July 9, 2021, the day on which the CAISO observed its peak 2021 demand to date, the CAISO was a net *exporter* across the gross load peak hours, and was limited to less than 3,000 MW of imports across the net load peak hours, because of wildfire-induced limits on the Pacific Direct Current Intertie and the California-Oregon Intertie.

Subsection C.4 (g). Staff proposes to authorize the IOUs to coordinate with the State to determine whether any temporary generation resources procured or leased in 2021 should be replicated for 2022. Based on publicly available information,[24] MRP is not aware that IOUs coordinated directly and exclusively with the State for such arrangements in 2021. MRP is concerned that authorizing the IOUs to coordinate directly and exclusively with the State precludes the State from coordinating with third parties and would give the IOUs an unnecessary and unfair advantage.

Subsection C.4 (h). As discussed earlier, MRP believes it is critically important to ensure that existing resources, particularly gas-fired resources, are procured to ensure reliability over the near-, mid- and long-term. As noted above, recent studies looking at long-term reliability needs indicate that a significant portion of the gas generation will still be needed even as the state heads towards reaching SB100 goals.[25] MRP supports Staff's proposal to order IOUs to pursue long-term contracts for gas generation resources to benefit all customers. Consistent with my proposal above, I also propose that long-term contracts with gas peaking generation must include a requirement to hybridize.

MRP, however, does not recommend creating, at this time, a requirement for gas-fired generation to use hydrogen in the future because currently there is insufficient evidence that hydrogen production and delivery at that scale can be viable and cost-effective in the near-term. While MRP strongly believes that hydrogen can and will play

[24] The August 24, 2021 Petition for Limited Tariff Waiver of the California Independent System Operator Corporation and request for Shortened Comment Period and Expedited Commission Approval, filed with the Federal Energy Commission in Docket No. ER21-2753, indicates that the California Department of Water Resources intended to deploy temporary emergency generation at Calpine Corporation and Balancing Authority of Northern California sites. While the Calpine Corporation site is within the Pacific Gas and Electric Company transmission system, Calpine, not PG&E, is deploying this generation.
[25] *See* FN 9-12.

a major role in preserving the duration-unlimited generation needed to ensure reliability while also reducing carbon emissions, the production, storage and transport of hydrogen fuel are complicated processes that require much additional research to ensure safe and reliable service. The Commission should not set a purely aspirational goal with regards to the use of hydrogen, but first should better understand when such goals can be realistically achieved.

Subsection C.4 (i). For nearly two decades, the Commission, the CAISO and supply and demand market participants have relied on the RA program to maintain reliability. To that end, the phrase "firm supply resources than can be available for dispatch to meet net peak load but do not otherwise meet Resource Adequacy obligations" is difficult to understand. The Commission is currently considering modifications to the RA program to address net load peak challenges; MRP believes it would be counter-productive and inefficient for the Commission to be simultaneously considering *outside of the RA program* resources that meet net peak loads.

Q. SHOULD THE IOU BUNDLED PROCUREMENT RULES BE MODIFIED TO ALLOW THE IOUS TO PRESERVE HYDRO GENERATION FOR MAXIMUM AVAILABILITY DURING STRAINED GRID CONDITIONS AS PROPOSED IN SECTION 5?

A. MRP believes that Staff's proposal mixes the concepts of energy must offer obligations with that of capacity counting. MRP interprets that Staff are concerned that, because of the least cost dispatch rules within the IOUs' bundled procurement plans that have been approved by the Commission, hydro resources are being offered into the CAISO's energy markets economically, which effectively allows hydro to be dispatched by the CAISO to meet system needs that could also include exports. This in turn reduces the amount of water levels available within the hydro system for use during summer times when demand is much higher. The recent situation in which generation at Lake Oroville has been taken off-line due to low water levels demonstrates that this is not just a theoretical concern. To address this, Staff proposes that the IOUs withhold hydro production in some hours to preserve that energy for later more critical hours. While MRP agrees that it is reasonable to conserve water for use later in the year, MRP expects that CAISO energy market prices are, or at least should be, the most reliable indicator of need and the best allocator of scarce resources. To that end, MRP supports the Commission working with the CAISO to consider opportunity cost adders that promote preserving hydro capability without encouraging or sanctioning economic withholding or interfering with energy market price formation.

Q. DOES THIS CONCLUDE YOUR TESTIMONY?

A. Yes, it does.

VERIFICATION

I, Brian D. Theaker, state that I am authorized to make this verification on behalf of Middle River Power LLC. I declare under penalty of perjury that the statements in the foregoing document are true of my own knowledge, except as to matters which are therein stated on information or belief, and as to those matters, I believe them to be true.

Executed on September 1, 2021, at Placerville, California.

/s/ Brian D. Theaker

Brian D. Theaker
Vice President Western Market and
Regulatory Affairs
Middle River Power LLC

APPENDIX 1

Middle River Power LLC Comments on Draft Stack Analysis
Submitted to the California Energy Commission on August 20, 2021
in Docket No. 21-ESR-01

August 20, 2021

California Energy Commission
Docket Unit, MS-4
Docket No. 21-ESR-01
1516 Ninth Street
Sacramento, California 95814-5512

Via electronic submittal

Dear Docket Unit, Commissioners and Commission Staff:

Middle River Power, LLC ("MRP") appreciates the opportunity to submit these comments on the Draft 2022 Stack Analysis ("Draft 2022 Analysis") as presented as Item 4 at the Commission's August 11, 2021 Business Meeting.

Introduction

MRP owns approximately 1.8 GW of natural gas-fired generation operating within the bulk power system under the operational control of the California Independent System Operator Corporation ("CAISO"). MRP has developed and is currently deploying with the current owners two battery energy storage systems ("BESS") totaling 110 MW and a 100 MW solar photovoltaic system connecting into the same interconnection facilities at MRP-owned generating plants.

Comments

Comments on the Stack Analyses

For ease of reference, MPR includes here as Figures 1, 2 and 3 the three Summer 2022 stack analyses as presented at the August 11, 2021 Business Meeting:[26]

[26] The July 2022, August 202 and September 2022 draft analyses were presented on slides 39, 40, and 41, respectively, of the presentation available at this link: https://efiling.energy.ca.gov/getdocument.aspx?tn=239252.

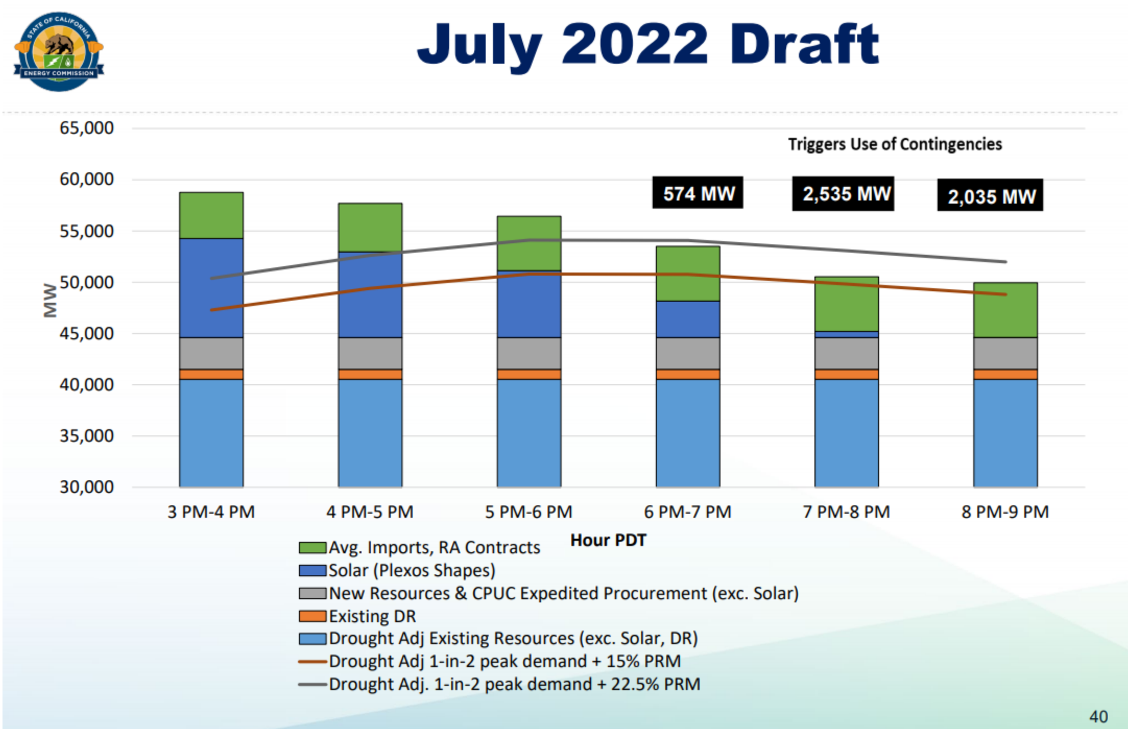


Figure 1 - July 2022 Preliminary Stack Analysis

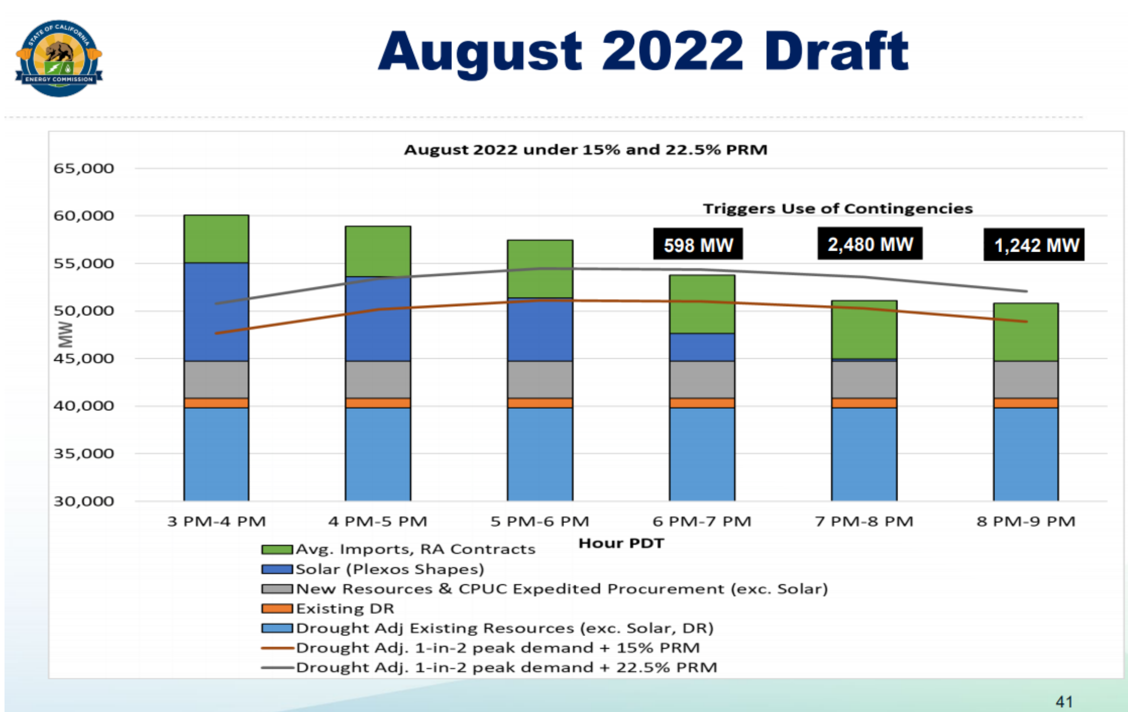


Figure 2 -August 2022 Preliminary Stack Analysis

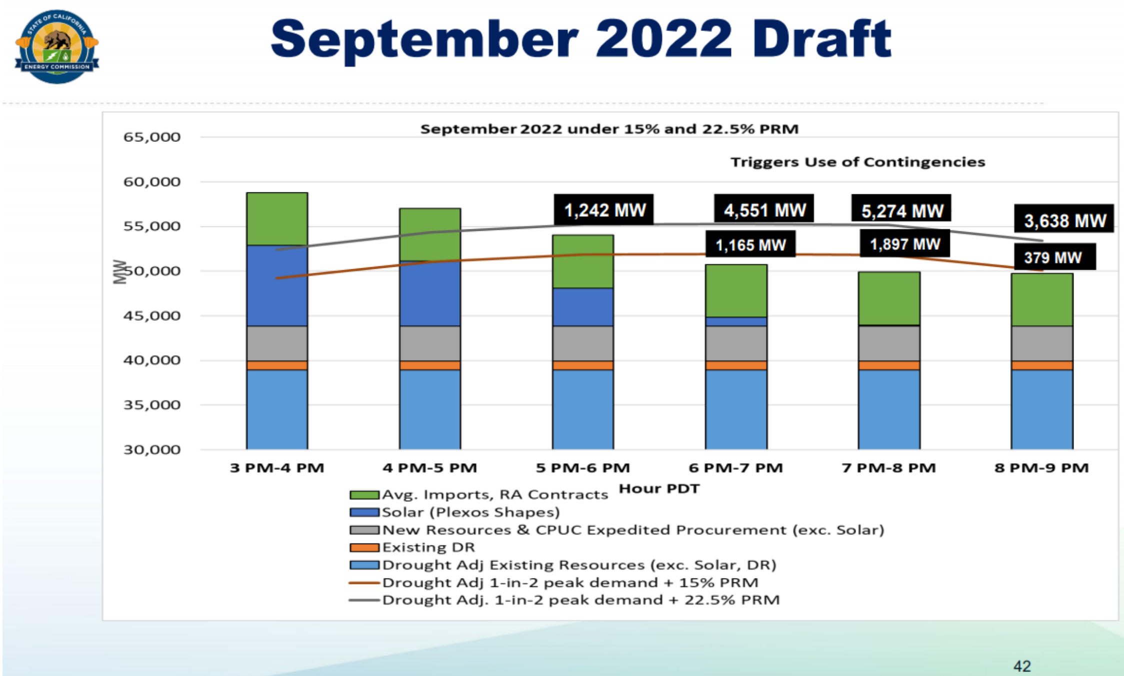


Figure 3 - September 2022 Preliminary Stack Analysis

These charts all project resource deficiencies in Hour Ending 20 (HE20, 7- 8 PM) ranging from 2,480 MW to 5,274 MW using a 1-in-2 drought-adjusted peak demand forecast plus a 22.5% Planning Reserve Margin ("PRM"). Additionally, the September 2022 analysis projects resource deficiencies between 1,165 MW and 1,897 MW in HE19, HE20 and HE21 with a 15% PRM.

As the accompanying narrative describes, the 22.5% PRM is intended to provide an additional 7.5% capacity margin for 1-in-10 weather year demand variability – a total of 9%, instead of the 1.5% assumed for load variability as part of the "traditional" 15% PRM.[27]

Before MRP comments on various details of the stack analysis, MRP reiterates its overarching concern that this stack analysis does not ensure whether additional procurement allows the system to meet a 0.1 loss of load expectation ("LOLE"). While the stack analysis attempts to meet 1-in-10 weather year demand, doing so is not the same as meeting a 0.1 LOLE. While the California energy agencies have used a 0.1 LOLE planning standard as a metric to maintain reliability, this near-term analysis does not indicate how any accelerated procurement will or will not achieve this standard over the mid- to long-term. Consequently, this analysis may result in additional procurement that cures resource shortfalls relative to a 1-in-10 weather year forecast

[27] See *California Energy Commission Preliminary 2022 Summer Supply Stack Analysis* at page 2, available at https://www.energy.ca.gov/filebrowser/download/3655.

demand but does not achieve a 0.1 LOLE. The energy agencies must undertake the more thorough stochastic analysis needed to assess the reliability need and determine what resources are required to meet the 0.1 LOLE standard in the most cost-effective way.

MRP now comments on various aspects of the stack analyses.

First, MRP supports using a PRM component higher than 1.5% to account for demand variability in the PRM. There is consensus that weather variability is increasing and hotter weather beyond "average" weather is increasingly likely in any given year. In other words, MRP does not believe that a 15% PRM continues to ensure 0.1 LOLE given the supply mix on the grid today. While using a 7.5% adder to account for increasing weather variability is understandable, this adder may or may not ensure a 0.1 LOLE either, especially depending on the type of resources procured to close the deficiencies. Again, without performing a stochastic LOLE analysis, it is not clear whether simply closing the projected resource deficiencies, even to a 22.5% PRM, will result in maintaining a 0.1 LOLE.

Second, the stack analyses all appear to assume that the same amount of demand response ("DR") that is available at 3-4 PM also will be available at 8-9 PM. MRP questions whether DR program response generally lasts longer than four consecutive hours to allow for such counting in the stack analysis. This seems highly unlikely, and should either be amended or justified.

Third, the stack analyses appears to mix apples and oranges (i.e., capacity and energy) with regards to resource counting. The "drought-adjusted existing resources (excluding solar and demand response)" column, which includes wind and hydro resources, does not change across the six hours presented. It therefore appears to use capacity values for wind and hydro resources rather than the hourly energy profiles used for solar resources. MRP recommends that, for variable resources (i.e., solar, wind and DR programs), the analysis should use conservative estimated hourly profiles rather than static MW capacity values associated with RA net qualifying capacity ("NQC"). For DR, if estimated hourly profiles are not readily accessible, then the next best option is to limit the duration in which DR programs would generally be dispatched.

Fourth, for each of these three months, the figures show the same value for "average imports, RA contracts" across each of the six hours. Inspecting these figures appears to show values of greater than 5,000 MW for imports for these three months in 2022. While the 2022 RA annual showings have not yet been made, MRP respectfully encourages the Commission to use prudently conservative assumptions about the availability of imports. MRP agrees that import values should be based on RA contracts, which should indicate that resources are committed to serving California load, and should not be based spot market import energy sales, which do not indicate whether the backing resources are, in fact, committed to serving California load.

Further, assuming that California will have access to historically "average" levels of imports even based on RA import contracts may be an unwise assumption. MRP notes that the CAISO was a net *exporter* across its peak gross demand on July 9, the day on which the CAISO observed its peak demand for 2021 to date. As Figure 4 shows, the CAISO's net imports were in the range of only 2,000 – 2,500 MW across its net peak demand time that same day. MRP acknowledges that multiple factors limited imports this day, including high temperatures in the Pacific Northwest (which caused high demand in other western load centers) and wildfire-driven reductions in transfer capability on both the California Oregon Intertie and the Pacific Direct Current Intertie. Nevertheless, these factors (increased competition for fewer resources across the west and wildfire-induced resource and transmission restrictions) suggest that it would be unwise to place undue reliance on out-of-state resources whose energy must be delivered on long-haul transmission.

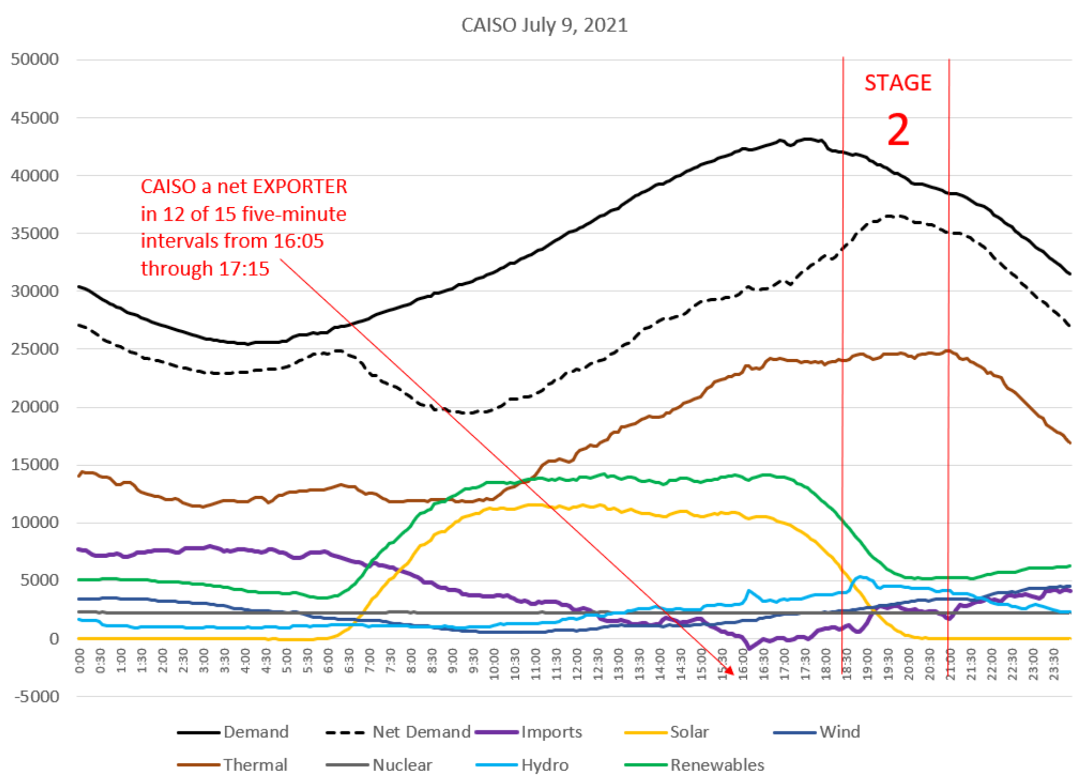


Figure 4 - CAISO Five-Minute Data from July 9, 2021

Source – CAISO Five-Minute Data available at http://www.caiso.com/TodaysOutlook/Pages/supply.html.

Fifth, MRP notes that most analyses assume that the entire thermal fleet – with the possible exception of the once-through-cooled resources - will be available at the current levels for the indefinite future. MRP cautions against relying on that assumption under the current one-year system RA program. MRP has been approached, and expects other California suppliers have been approached as well, by load-serving entities outside the CAISO balancing authority area offering multi-year contracts to in-CAISO resources to serve as supporting resources for exports from the CAISO BAA. To the extent internal generation is contracted to serve load outside of the CAISO BAA, the staff analysis should account for those commitments and should not automatically assume that in-state generation will be available to serve CAISO load.

Sixth, the analysis indicates that nearly 5,000 MW of new resources will be available for August 2022. MRP questions if the Commission assumed correctly that such new resources, which MRP expects will be four-hour battery resources, are truly available for the entire six-hour duration of HE 16 through HE 21. To the extent that such new resources are primarily four-hour storage resources, the analyses should only reflect the reliability contribution towards the hours of most need. Better shaping the new resource stacks to reflect four-hour availability may reveal deficiencies in other hours as well. For example, it is possible a deficiency may occur during HE 21 if the new four-hour resources are all used up by HE 20. Likewise, if the four-hour resources are "saved" for HE 18 through HE 21, then deficiency may occur at HE 17 during September in this stack analysis, though such deficiencies are less likely because of the additional solar production at HE 17. In any case, given the expectation that many of the new resources procured will be four-hour battery resources, the stack analysis should not assume those resources are available for a six-hour strip.

With regards to new resources, the analyses seem to indicate that nearly 5,000 MW of new resources will be available for August 2022, but that approximately only 4,000 MW of new resources are expected to be available for September 2022. Given the presumption that any new resources that is available for August will also be available for September, the difference between these August and September values, if they are, in fact, capacity values, is unclear. If the values are not capacity values, but energy values, then it is not clear why the values would be same for all six hours and not shaped, especially if the underlying resources have solar components.

Finally, to reiterate, while these stack analyses identify projected gaps between deterministic demand and supply projections, MRP respectfully urges the Commission to swiftly move beyond the simplistic stack analyses to the data-rich stochastic LOLE analyses that must be performed to determine whether any short-term procurement undertaken to cure the stack analysis gaps will, in fact, ensure California achieves a 0.1 LOLE, and will do so without incurring unnecessary expense to drive system reliability beyond 0.1 LOLE.

MRP cautions that while the analysis may result in higher procurement targets, the results cannot be directly translated to "revised" requirements associated with the RA program. This is because the RA program allows LSEs to count the capacity value of all resources, specifically, that of solar resources, to meet the HE19 to HE20 net peak requirements to which the CEC analysis shows little, if any, contribution. As such, under current RA program rules, resources procured to cover the HE19 and HE 20 net load peaks will also count towards meeting RA program requirements, which are based on gross load peaks. Because the resource stacks for the gross load peaks may not be deficient, capacity procured to meet the net load peaks may lead to a surplus of capacity procured to meet the gross load peaks, which could displace capacity needed to meet both the gross and net load peaks. Because the CEC analyses do not fully align with RA program targets and counting methodologies, they require additional steps to be converted to RA program requirements. Again, to reiterate, merely covering the projected deficiencies will not ensure that resulting system meets the 0.1 LOLE target; more sophisticated analysis is required to assess that.

Request for Supporting Data

The stack analyses are presented in graphs without any accompanying numerical data. To better allow entities to use and validate the analysis and to conduct their own analysis, MRP respectfully requests that the Commission provide underlying data tables, with as much resource type-specific information as possible, for this analysis and for any future analyses.

Conclusion

MRP thanks the Commissions for the opportunity to submit these comments on the Preliminary 2022 Stack Analyses. MRP respectfully urges the Commissions (1) conduct the robust stochastic analysis needed to thoroughly assess the proposed procurement, including its cost-effectiveness, and (2) convert its recommendations to align with RA program counting rules and methodologies to ensure that the CPUC applies the appropriate reliability targets so that no existing capacity is unintentionally displaced. Finally, MRP requests that the Commission provide the numerical information underlying these analyses and all future analyses.

Respectfully submitted,

/s Brian Theaker

Brian Theaker
Vice President Western Regulatory and Market Affairs
Middle River Power LLC
4350 Executive Drive, Suite 320
San Diego, California 92121
Phone: (530) 295-3305

Attachment 1

Brian D. Theaker Resume

Brian D. Theaker

Work phone: (530) 295-3305 ▪ Cell phone (530) 320-3596 ▪ Work e-mail btheaker@mrpgenco.com

EDUCATION

1989	**Masters in Business Administration** Pepperdine University, Malibu, California
1983	**Bachelor of Science in Electrical Engineering**, power option Ohio State University, Columbus, Ohio

EXPERIENCE

2019 to present
Middle River Power LLC. from home office
Vice President Western Regulatory and Market Affairs
- Participated in and reported on federal and state regulatory proceedings, trade association and regional reliability council activities affecting Middle River Power's interests
- Drafted, reviewed, analyzed and summarized regulatory filings

2011 to 2019
NRG Energy, Inc. Sacramento, California and from home office
Director, Regulatory Affairs
- Participated in and reported on federal and state regulatory proceedings, trade association and regional reliability council activities affecting NRG Energy's interests
- Drafted, reviewed, analyzed and summarized regulatory filings

2007 to 2011
Dynegy, Inc. Sacramento, California and from home office
Director, Regulatory Relations
- Participated in and reported on federal and state regulatory proceedings, trade association and regional reliability council activities affecting Dynegy's interests
- Drafted, reviewed, analyzed and summarized regulatory filings

2005 to 2007
Williams Power Company, Inc., Tulsa, Oklahoma (remotely from home office)
Regional Governmental Affairs Manager
- Participated in and reported on federal and state regulatory proceedings, trade association and regional reliability council activities affecting Williams' interests
- Drafted, reviewed, analyzed and summarized regulatory filings

2001 to 2005
California Independent System Operator Corporation, Folsom, California
Director of Regulatory Affairs - Legal & Regulatory Department
- Prepared and directed the preparation of various types of FERC filings
- Managed stakeholder processes on policy matters
- Analyzed and reported on regulatory matters for management and Board

1999 to 2001
California Independent System Operator Corporation, Folsom, California
Manager of Reliability Contracts - Contracts and Compliance Department
- Managed the negotiation and administration of Reliability Must-Run contracts and Summer Reliability Agreements

1999
California Independent System Operator Corporation, Folsom, California

Brian D. Theaker

Manager of Operations Engineering - Grid Operations Division
- Supervised Operations Engineers conducting power flow studies and preparing operating procedures
- Continued as the ISO's lead for Reliability Must-Run matters

1997 to 1999
California Independent System Operator Corporation, Alhambra, California
Operations Engineer - Grid Operations Division
- Served as the ISO's primary negotiator for Reliability Must-Run contracts
- Developed a revenue forecast model for Reliability Must-Run units and supporting testimony for a FERC proceeding

1986 to 1997
Los Angeles Department of Water and Power, Los Angeles, California
Electrical Engineering Associate - Security Assessment Group
- Performed power flow and composite reliability analysis of the high voltage bulk power system, including HVDC systems
- Prepared and presented WECC disturbance reports and public briefings
- Developed operations applications, including a hydro-thermal optimization

1983 to 1986
Los Angeles Department of Water and Power, Los Angeles, California
Electrical Engineering Assistant - Research Group
- Designed, supervised, evaluated and reported on special power system tests, including ground grid evaluation, equipment failure analysis, telephone interference measurement, and simulating relay performance

- Member of the Western Electricity Coordinating Council Board of Directors, April 2008 – January 2013
- Registered Professional Engineer in California (License Number E 12612)
- Western Power Trading Forum Kent Wheatland Award 2010
- WECC Outstanding Contributor Award 2009
- Chair of the WECC Minimum Operating Reliability Criteria Work Group, 1998-1999
- Chair of the WECC Bulk Electric System Definition Task Force, 2009-2011
- Member of the LADWP Speakers' Bureau, 1995-1997
- References available on request