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BEFORE THE PUBLIC UTILITIES COMMISSION OF THE STATE OF CALIFORNIA

Order Instituting Rulemaking to Oversee the Resource Adequacy Program, Consider Program Refinements, and Establish Forward Resource Adequacy Procurement Obligations.	Rulemaking 19-11-009

ADMINISTRATIVE LAW JUDGE'S RULING ON ENERGY DIVISION'S TRACK 3.B PROPOSAL

Pursuant to the Track 3.B schedule set forth in the Assigned Commissioner's Amended Scoping Memo and Ruling, attached to this ruling is Energy Division's Track 3.B proposal.

IT IS RULED that the Commission's Energy Division's Track 3.B proposal is attached to this ruling as Appendix A.

Dated August 7, 2020, at San Francisco, California.

/s/ DEBBIE CHIV
Debbie Chiv
Administrative Law Judge

APPENDIX A

California Public Utilities Commission

August 7, 2020

Energy Division Issue Paper and Draft Straw Proposal for Consideration in Proceeding R.19-11-009, Track 3B

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List of Acronyms

AB	Assembly Bill	**MCC**	Maximum Cumulative Capacity
CAISO	California Independent System Operator	**MMT**	Million Metric Tons
CAM	Cost Allocation Mechanism	**MOO**	Must Offer Obligation
CCA	Community Choice Aggregator	**MW**	Megawatt
CHP	Combined Heat and Power	**MWh**	Megawatt Hour
CPE	Central Procurement Entity	**NQC**	Net Qualifying Capacity
CPUC or Commission	California Public Utilities Commission	**PCL**	Power Content Label
CRT	Customer Risk Tolerance	**PG&E**	Pacific Gas and Electric Company
D.	Decision	**Pmax**	Maximum Power Output
DA	Direct Access	**PRG**	Procurement Review Group
DEB	Default Energy Bid	**PUC**	(California) Public Utilities Code
DMM	CAISO Department of Market Monitoring	**QC**	Qualifying Capacity
DR	Demand Response	**R.**	Rulemaking
DWR	California Department of Water Resources	**RA**	Resource Adequacy
ELCC	Effective Load Carrying Capability	**RAR**	Resource Adequacy Requirements
EIM	Energy Imbalance Market	**REF**	Resource Eligibility Factor
ESP	Electric Service Provider	**RNS**	Residual Net Short
FERC	Federal Energy Regulatory Commission	**RPS**	Renewables Portfolio Standard
GHG	Greenhouse Gas	**RSP**	Reference System Portfolio
GWh	Gigawatt Hour	**RUC**	Residual Unit Commitment
IOU	Investor-Owned Utility	**SB**	Senate Bill
IRP	Integrated Resource Planning	**SCE**	Southern California Edison
LD	Liquidated Damage	**SDG&E**	San Diego Gas & Electric
LOLE	Loss of Load Equivalency	**SFPFC**	Standardized Fixed-Price Forward Contract
LIP	Load Impact Protocol	**TAC**	Transmission Access Charge
LSE	Load Serving Entity	**TEVaR**	To Expiration Value at Risk
LTPP	Long Term Procurement Planning	**UOG**	Utility-Owned Generation
LRA	Local Regulatory Authority	**WECC**	Western Electricity Coordinating Council

I. Introduction

With the passage of Assembly Bill (AB) 1890 (Brulte, 1996), California transitioned from procuring electricity primarily through the traditional vertically integrated utilities to a "restructured" or "deregulated" electricity market. At the time, policymakers and others were concerned that the vertically integrated electricity system suffered from inefficiencies, that costs were too high, and that there were insufficient incentives to invest in electricity generation plants. AB 1890 allowed customers in the service territories of California's investor-owned utilities (IOUs) to buy electricity in an open market from non-IOU entities such as Electric Service Providers (ESPs). It also established the California Independent System Operator (CAISO), an independent, non-profit transmission system operator.

Within a few years of implementation of AB 1890, the California energy crisis had occurred. The utilities had sold off most of their generation and were at the mercy of sellers to meet their load. The high wholesale prices that the utilities had to pay for electricity during this period resulted in rolling blackouts as well as the bankruptcy of the largest IOU, Pacific Gas and Electric Company (PG&E), and the near bankruptcy of the other two large IOUs, Southern California Edison (SCE) and San Diego Gas & Electric (SDG&E).

For the last two decades, policymakers and state regulators have aimed to ensure that the electric system remains reliable and affordable, while also working to achieve ambitious clean energy goals and to allow for retail choice. This evolution has resulted in a reliability framework with a long-term integrated resource planning process, a year-ahead system resource adequacy (RA) program and a multi-year local RA program. As the topology of the grid evolves, the reliability framework may need to change as well. Accordingly, this Energy Division staff issue paper and proposal discusses the issues that are arising with respect to the current reliability framework and proposes, at a high level, three different potential paths forward that merit further discussion and consideration in Track 3B of the California Public Utility Commission's (CPUC) Resource Adequacy Proceeding, Rulemaking (R.)19-11-009.

A. Goals and Problem Statement

The Commission's reliability construct should balance reliability with least costs to customers while also ensuring that the State is able to facilitate a least-cost transition to a reliable, decarbonized electrical grid, and foster retail competition. A capacity framework, such as the one currently in place, may not most efficiently balance these goals.

Some of the key challenges in designing an optimal reliability framework, in this context, include:

- Addressing the significant decline in long-term tolling gas agreements which are being replaced by RA only contracts.
- The capacity construct does not ensure that electrons will flow or curtailment of demand will occur, which can lead to speculative supply issues.
- The shrinking gas fleet and dependence on it to meet critical peak hours of the day when must-take variable energy resources are not available.
- Greater dependence on a suite of use limited resources to meet the state's hourly reliability needs requires further modifications to the current maximum cumulative capacity (MCC) buckets structure to ensure the requirements are binding.

- Lack of an adequate system market power mechanism to mitigate energy market price spikes that could increase costs for all California customers.
- Growth in retail choice and the relationship with the provider of last resort makes it difficult to plan for reliability, if entities do not know whether they will be serving future load. This load uncertainty prevents entities from entering into long-term contracts with new or existing resources.

B. Purpose and Outline

Absent action by the CPUC and industry stakeholders, these challenges may increase ratepayer costs and strain electric reliability. The current RA proceeding, R.19-11-009, scoped Track 3 to include an:

> [e]xamination of the broader RA capacity structure to address energy attributes and hourly capacity requirements, given the increasing penetration of use-limited resources, greater reliance on preferred resources, rolling off of a significant amount of long-term tolling contracts held by utilities, and material increases in energy and capacity prices experienced in California over the past years.

The remainder of this paper is organized as follows.

- Section 2 provides background information on a variety of topics related to the current market structure, including requirements put in place after the energy crisis, other reliability and clean energy requirements, and mechanisms developed in the RA proceeding to address over-reliance on use-limited resources.
- Section 3 discusses issues that have arisen in recent years, including resource retirements and potential reductions in available resources in California and throughout the West, reduction in tolling contracts and forward energy contracts, increases in capacity and energy prices and/or volatility, market fragmentation that has raised concerns about the provider of last resort, insufficient bonding and recourse in the case of default or market exit, and system market power issues that have arisen as a result of these trends.
- Section 4 discusses, at a high level, three potential paths forward as well as potential questions associated with these different paths.
- Section 5 discusses a potential schedule for discussing the issues associated with broader reform of the State's resource adequacy framework.

II. Background

A. History of Procurement Policy

California's capacity and energy markets have evolved significantly over the last three decades. In 1995, California still operated under a vertically integrated market structure where the three IOUs owned and operated the generation, distribution and transmission of the electrical system. In 1995, the Commission issued a comprehensive decision for electric restructuring, which included the adoption and implementation of a direct access program.

A direct access customer receives distribution and transmission service from the utility, but purchases its electric energy from its ESP. A utility's bundled customer can choose to become a direct access customer and later revert to bundled customer status. The utility is the electricity provider of last resort. The ability to leave the utility system and return may cause substantial fluctuations in the amount of energy the utility must purchase (or has purchased) on its behalf.

In response to the energy crisis, the Legislature enacted AB 1X-1 (Keeley, 2001),[1] which authorized the California Department of Water Resources (DWR) to enter into long term-contracts with power suppliers for the purpose of selling electricity to utility retail customers. This was necessary, at the time, as the utilities were not financially able to meet their net short needs. In addition, pursuant to AB 1-X, the Commission also suspended the right for retail end use customers to acquire service from other providers until DWR no longer supplied power.[2]

Following AB 1X-1, the Legislature enacted AB 57 (Wright, 2002),[3] which added Public Utilities Code (PUC) section 454.5. This section of the code directed the IOUs to file procurement plans with the CPUC that included, among other provisions:

> (1) An assessment of the price risk associated with the electrical corporation's portfolio, including any utility retained generation, existing power purchase and exchange contracts, and proposed contracts under which the electrical corporation will procure electricity, electricity demand reductions, and electricity related products and the remaining open position to be served by spot market transactions….
>
> (10) The electrical corporation's risk management policy, strategy, and practices, including specific measures of price stability.[4]

In addition, the statute required that the procurement plan show that the IOU would "create and maintain a diversified procurement portfolio consisting of both short-term and long-term electricity and electricity related and demand reduction products."[5]

In implementing AB 57, CPUC Decision (D.) 02-10-062,[6] adopted a regulatory framework that directed the three large IOUs to resume full procurement responsibilities on January 1, 2003. The framework contained requirements for an expedited review process and timely cost recovery that conformed with the legislation's statutory requirements. It also addressed the utilities' reliance on spot market purchases, by providing the following guidance:

> While we wish to provide utilities with timing flexibility in meeting their residual net short needs [RNS], it is not our intention to have the entire RNS market met in the spot market. Though we do not set an explicit limit on spot market purchases, utilities should plan to minimize their spot market exposure and should justify their planned spot market purchases if they exceed 5% of monthly needs.[7]

In implementing Pub. Util. Code §454.5, the Commission was required to (1) assess the price risk associated with each utility's portfolio; (2) ensure the utility has moderated its price risk; and (3) ensure the adopted procurement plan provided for just and reasonable rates, with an appropriate balancing of price stability and price level. (Sections 454.5(b)(1), 454.5(d)(4), and 454.5(d)(5).)

The Commission developed its procedures to monitor and manage rate level risk primarily in three decisions, D.02-10-062, D.02-12-074, and D.03-12-062. These procedures make use of two metrics, the Customer Risk Tolerance (CRT) and the To Expiration Value at Risk (TEVaR). The TEVaR represents an estimate, at a given confidence level, of the amount of electric rate increase that could occur due to changes in market conditions such as nuclear outage risk, hydro-power availability risk, electricity spot market price volatility, credit risk, and gas price volatility (which represents the single greatest historical source of price volatility). For example, TEVaR 95% measures the maximum rate increase over the expected value with 95% confidence level (in other words, it is the 1-in-20 worst case scenario). CRT essentially is a cap on unforeseen electric rate increases looking 12 months into the future due to electric procurement activity. In D.12-01-033 the Commission set the CRT rate at 10% of the utility's system average rate.

Each IOU is required to analyze portfolio risk based on a probability distribution of risk factors and should report portfolio risk using TeVAR measurement at the 95th percentile. (D.03-12-062 COL 5 and D.07-12-052 at OP 21.) CRT and TEVaR can be expressed either as cents per kWh (that is, the average electric rate fluctuation), or dollars per year (the total portfolio cost fluctuation). The portfolio value is obtained by multiplying the rate value times the amount of kWh sales over a 12-month period for that utility.

The Commission requires the utilities to submit monthly TeVAR reports to Energy Division that reflect the 95th percentile TEVaR reporting measured on a rolling 12-month basis. These monthly reports also report the TEVaR 95% on a quarterly basis for months 13-24 ahead, and on an annual basis for months 25-60. In the event that the 12-month TEVaR 95% value exceeds 125% of the CRT, then the utility calls a special meeting of its procurement review group (PRG) to review the causes for the high volatility and decide whether new hedges are needed to bring TEVaR back within the allowed threshold.

B. Resource Adequacy

To further ensure reliability, the Legislature passed AB 380 (Nunez, 2005),[8] which was codified as PUC Section 380. This section required the CPUC to establish RA requirements for CPUC jurisdictional load serving entities (LSEs),[9] in consultation with CAISO. Under the RA program, each LSE must commit its own generation – or contract with generators owned by other entities – to ensure reliability of the electric system. Section 380 also requires LSEs to meet the minimum reliability and planning criteria specified by the Western Electricity Coordinating Council (WECC).

In the aftermath of the electricity crisis of 2000-2001, California wrestled with the creation of a resource adequacy program that recognized the realities of California's hybrid market structure. In D.04-01-050, the Commission described the concept of RA and the role of RA requirements as:

> Resource procurement traditionally involves the Commission developing appropriate frameworks so that the entities it regulates will provide <u>reliable service at least cost</u>. This involves determining an appropriate demand forecast and then ensuring that the utility either controls, or can reasonably be expected to acquire, the resources necessary to meet that demand, even under stressed conditions such as hot weather [footnote omitted] or unexpected plant outages. 'Resource adequacy' seeks to address these same issues. In developing our policies to guide resource procurement, the Commission is providing a framework to ensure resource adequacy by laying a foundation for the required infrastructure investment and assuring that capacity is available when and where it is needed." (D.04-01-050, pp. 10-11.)

D.04-01-050 also adopted the following RAR policies applicable to LSEs:

(1) Each LSE within an IOU's service territory has an obligation to acquire sufficient reserves for its customers' load located within that service territory.
(2) Each LSE is subject to a planning reserve margin (PRM) requirement of 15-17% for all months of the year. Each LSE must meet this obligation no later than January 1, 2008 through a gradual phase-in, with interim benchmarks becoming effective in 2005.
(3) Each LSE must forward contract 90% of its summer (May through September) peaking needs (loads plus planning reserves) a year in advance, subject to adjustment if implementation would result in significantly increased costs or foster collusion and/or the exercise of market power in the Western energy markets.
(4) <u>The 5% target limitation on utilities' reliance on the spot market (i.e., Day-Ahead, Hour-Ahead, and Real-Time energy) to meet their energy needs is continued in effect.</u>
(5) <u>The Commission reiterated its commitment that full value be given to the preferred resources identified in the California Energy Action Plan and to the long-term DWR contracts.</u>

(Emphasis added.)

In D.04-10-035, the CPUC adopted the requirement that each LSE must acquire a mix of resources capable of satisfying the number of hours for each month that their loads are within 10% of their maximum contribution to monthly system peak. It was expected that this flexibility would allow LSEs to find optimal portfolios of resources that matched their loads at least cost while also ensuring that collectively, reliability requirements for the service area were satisfied. In deciding this, the CPUC stated, "we are concerned that using an approach that fails to reflect the LSE's load shape could lead to inappropriate cost shifting." The decision also noted that "the issue of basing the RA obligation on a single peak hour verses multiple hours was closely related to the counting issue associated with energy limited resources.

In D.05-10-042 the Commission reiterated the concept of RA adopted in D.04-01-035, and stated that:

> the Commission envisions the resource adequacy program as the means by which the function of reliably matching resources to demand at least cost will be accomplished in the current industry environment. Historically, this function was the responsibility of integrated utilities that provided bundled service to retail customers, and the regulatory compact provided clear standards for utility accountability along with the opportunity for the utility's investors to earn a reasonable return on the investment they devoted to public service. Procurement and reliability responsibilities that were once the IOUs' are now diffused among various industry participants and oversight agencies, and both accountability mechanisms and the opportunities for investment returns are less well defined. Through [Resource Adequacy Requirements] RAR, the Commission is taking steps to (1) identify and assign these responsibilities in a manner that is effective in achieving reliability, cost-efficient, and fair for all stakeholders; and (2) foster an environment that is more conducive to investment.

Finally, the Commission noted that the traditional utility role in procurement included the responsibility to provide reliable service at least cost, and that this is one of the "same issues" of traditional resource procurement that RAR seeks to address. Thus, the concept embodied in the phrase "reliability at any cost" is not a policy option. Ultimately, measures that are proposed to promote greater grid reliability should be evaluated by weighing their expected costs against the value of their expected contribution to reliability.

In D.05-10-042, the CPUC adopted a monthly system peak approach (top-down) to defining the (RA obligation instead of an LSE-specific resource duration curve approach (bottom-up). These two approaches were known as the top-down and bottom-up methods.

Under the bottom-up approach a resource eligibility factor (REF), a proposed measure of the percent of time resources can be counted against an LSE's RAR, would be used to compare the LSE's resource portfolio to the resource duration curve. Non-energy-limited resources without planned outages would have a 100% REF, i.e., they would count towards an LSE's monthly RAR 100% of the time. Certain energy-limited resources could meet the 100% REF standard in specified conditions; otherwise, however, energy-limited resources would not be able to qualify for a 100% REF.

The CPUC also expressed its intent to move towards a physical, capacity-based RA program and away from an LSE procurement strategy that utilized liquidated damage (LD) contracts (financial products) to meet reliability (which do not identify physical capacity). Specifically stating: "We find that LD contracts are fundamentally incompatible with achieving the objectives of a physical capacity-based RAR program and that, ultimately, their eligibility for fulfillment of LSEs' capacity obligations should be disallowed." It was determined that the physical capacity-based program, should only allow resources to count to the extent that their capacity can be relied upon to perform.

In D.05-10-042, the CPUC determined that an RA capacity contract that includes the following minimum elements, would be eligible to meet their RA procurement obligations:

1. Capacity must meet the counting protocols adopted by the CPUC in D.04-10-035, intoday's decision, and as modified in subsequent Commission decisions.
2. Capacity must meet the deliverability requirements as determined by the CAISO.
3. Capacity cannot be sold to more than one buyer. Buyer has exclusive right to count the Capacity towards buyer's Resource Adequacy Requirements.
4. Capacity must be subject to CAISO Tariff.
5. Capacity must be made available to the CAISO as outlined by the CPUC. Namely:
    a. Capacity must be made available to the CAISO for all hours of every day of the contract term in the following manner
    b. Capacity must be scheduled by the LSE.
    c. Capacity must be bid into the forthcoming Day-Ahead market if not already scheduled.
    d. Capacity must be subject to the CAISO's Residual Unit Commitment (RUC) process if the bid is not accepted. Capacity must submit a zero dollar ($0) bid into RUC. Capacity will not be eligible for any RUC availability payment or revenue.
    e. Capacity must be made available subject to the existing Federal Energy Regulatory Commission's (FERC's) Must Offer Obligation (MOO) or if MOO is no longer operative, Capacity shall be made available subject to the same obligations and timelines that exist under the current MOO process.

1. Qualifying Capacity Methodologies

The valuation of capacity products is a key aspect of the current RA program framework. Because the RA requirements are determined based on peak load, a resource's valuation is based upon its contribution to meeting peak reliability needs. Qualifying capacity (QC) methodologies vary by technology type and dispatchability status. Resources that are dispatchable, with the exception of hydro, wind and solar resources, receive QC value based on their maximum power output (Pmax) value. Dispatchable generation that utilize this methodology includes a variety of technologies, including: steam turbines; combustion turbines; combined cycle gas turbines; reciprocating engines; and dispatchable combined heat and power (CHP), biomass, and geothermal resources. Use limited resources may be classified as dispatchable.

In the recent Track 2 RA decision, D.20-06-031, the QC methodology for dispatchable hydro resources was modified to a methodology that looks at 10 years of historical bidding data over the availability assessment hours to determine the QC value of the resource. A dispatchable hydro resource can choose whether to use Pmax or to the new methodology. The key reason in moving to the new methodology was to better account for water use-limitations regardless of dispatchability status. For example, if there are low hydro conditions that need to be accounted for, the hydro resource would reflect these limitations in the megawatt (MW) amounts of its bids into the CAISO markets. A ten-year time frame was a better reflection of the weather trends that affect these resources than three-year historical average production or the Pmax value that does not do a good job of considering water availability.

Wind and solar facilities receive a QC based on a methodology known as effective load carrying capability (ELCC), adopted in D.17-06-027. An ELCC value is based on a loss of load equivalency (LOLE) study that looks at the effective capacity the resource will provide under a stochastic model assessment of the likelihood of a loss of load compared to a perfect generator (which uses a .1 1-in-10 reliability criteria). The capacity value of these resources account for the variability of the resource production at various hours that may coincide with a loss of load event. Monthly ELCC values are determined using this methodology resulting in wind and solar technology factors that are then applied to the resources' nameplate value.

Non-dispatchable generation, which historically included hydro, cogeneration, geothermal and biomass facilities, receive QC values based on methodologies that utilizes average historical production data or bids into the day-ahead market during the peak load hours.

The hybrid QC methodology, which includes solar plus energy storage and wind plus storage resources (both co-located and not co-located) was recently modified in D.20.06-031. The current methodology bases QC value on the sum of the QC values of each component adjusted for the energy needed to charge the storage resource. The methodology assumes that the battery will charge solely from the renewable generator. It looks at the monthly energy expected to be produced by the generator during the period from two hours after net load peak to two hours before net load peak the following day. If the expected energy is sufficient to fully charge the battery, the battery component receives a QC of Pmax. If not, the QC value will be reduced to the portion of the battery expected to be charged. If there is remaining energy produced by the renewable, the ELCC factors are applied to the renewable capacity associated with production of that remaining energy.

Demand response (DR) resources receive a value based on application of the load impact protocols (LIPs) which look at historic performance and temperature sensitivity to forecast load drop over the availability assessment hours.

QC methodologies vary widely in determining what available resource adequacy value the system can rely on to meet monthly peak load conditions. For a dispatchable resource, there is no devaluation of the resource if it has an air permit restriction or contractual use limitation that requires the resource to run less whereas the QC value of non-dispatchable generation is based on the average historical availability during the peak hours each month. Wind and solar QC values also account for energy production (using energy production curves). Hydro resource values take into account use limitations by incorporating historical energy bids into the market which account for outages due to water restrictions.

Once QC values have been calculated, the CAISO runs a deliverability study on the QC values to determine the net qualifying capacity (NQC) of the resource. The NQC value is what the resource can sell to LSEs in the market to meet RA requirements for the coming compliance year.

All resources, based on their NQC value, have a 24 X 7 MOO into CAISO markets, ensuring that the resource is bidding into the market and available for its contracted RA value. The bidding requirements also allow the resource to reflect use-limitations in each bid. That would mean if a resource is reaching a use-limitation, it may bid higher prices into the market to reflect these use limitations.

2. Maximum Cumulative Capacity Buckets

In developing the system RA program, the Commission contemplated what framework could address the use-limitations of resources used to meet peak load needs. In addition to providing a QC value based on a resource's contribution to meeting peak load conditions, the Commission also elected for a top-down approach to ensure that use-limited resources were not overly relied upon.

This top down approach utilizes a historical load duration curve to establish maximum cumulative percentages of an LSE's procurement obligation that can be met with use limited resources or contracts that provide less than 24 X 7 hours of availability per week in each month. These "buckets" were later modified in D.11-10-003 to add a DR bucket and then in D.12-06-025 to revise the percentages in the MCC buckets based on 2009-2011 load duration curves and implement the DR bucket adopted in D.11-10-003.

In D.20-06-031, the CPUC once again revised the MCC buckets, in part to address potential over-reliance on demand response resources, which until this time had been uncapped, and on other use-limited resources and to update the load duration curves. Further, since solar and wind resources were historically included in Category 4, despite not actually being available 24x7, a cap was set on solar and wind using the net load curve to ensure that sufficient resources would be available at all times. The two tables below compare the old MCC bucket structure to the newly adopted structure.

Table 1. Old MCC Bucket Structure

Category	Availability	Maximum Cumulative Capacity for Bucket and Buckets Above
1	Greater than or equal to the Use limited Resource (ULR) monthly hours. ULR hours for May through September are, respectively: 30, 40, 40, 60, and 40.	16.2%
2	At least 160 hours	21.7%
3	At least 384 hours	33.8%
4	Unrestricted	100.0%
DR	No limit, must be available at least 24 hours per month	100.0%

Table 2. New MCC Bucket Structure

Category	Availability	Maximum Cumulative Capacity for Bucket and Buckets Above
DR	Varies by contract or tariff provisions, but must be available Monday – Friday, 4 consecutive hours between 4 PM and 9 PM, and at least 24 hours per month from May - September	8.3%
1	Monday – Friday, 4 consecutive hours between 4 PM and 9 PM, and at least 40 hours per month from May – September	16.0%
2	Every Monday – Friday, 8 consecutive hours that include 4 PM – 9 PM	22.2%
3	Every Monday – Saturday, 16 consecutive hours that include 4 PM – 9 PM	34.8%
4	Every day of the month. Dispatchable resources must be available all 24 hours.	100% (at least 56.1% available all 24 hours)

In addition to updating the percentages and availability definitions for each bucket, the CPUC defined what availability meant by adopting the following definition:

> (1) Holding aside use limitations or outages, a resource is physically capable of dispatching the entire capacity designated in the given bucket in any and all hours associated with the minimum criteria for that bucket consistent with Resource Adequacy rules;
>
> (2) Holding aside use limitations or outages, the resource will economically bid or self-schedule (in the CAISO markets) the entire capacity designated in the given bucket in any and all hours associated with the minimum criteria for that bucket; and
>
> (3) If the resource has use limitations, the resource is not, solely due to the use limitations, unable to bid, self-schedule, and dispatch during regular, specific hours associated with the minimum criteria for that bucket.

The decision also noted that the ability to bid or self-schedule in the CAISO markets is a necessary but insufficient criterion for categorization in any given bucket – physical capability is also required.[10] The decision recognized that many parties still had concerns with the bucket structure, and clarified that the MCC buckets may be reconsidered and refined in Track 3.

C. IOU Procurement for System Reliability and Other Policy Goals

To support the development of new generation resources to ensure electric reliability, the Commission adopted the cost allocation mechanism (CAM), which allows the costs and benefits of new generation to be shared by all benefiting customers in an IOU's service territory. The Commission designated the IOUs to procure the new generation through long-term power purchase agreements, and the rights to the capacity were allocated among all LSEs in the IOU's service territory. The allocated capacity rights can be applied toward each LSE's RA requirements. In exchange for those benefits, the LSEs' customers – termed "benefitting customers" – pay for the net cost of the capacity.[11] The CPUC described the need for CAM as follows:

> We have found that long-term contracts are necessary to solicit investment in new generation in California, and both the ESPs and the IOUs are unwilling to sign long-term contracts. The ESPs' customers are on short-term contracts and the ESPs cannot recruit new customers with the suspension of [Direct Access] (DA). The IOUs are concerned that without some cost allocation provision to assure that their bundled customers are not left paying for new generation in the face of departing load, that long-term contracts are too risky.[12]

Additionally, D.06-07-029 states that "Pub. Util. Code §380 allows the costs an IOU incurs to sustain system reliability and local area reliability to be fully recovered from all customers on whose behalf the costs are incurred. It is consistent with AB 380 for the Commission to adopt the cost-allocation methodology set forth herein so that the IOUs' bundled customers are not alone responsible for the cost of new generation to retain system reliability."[13]

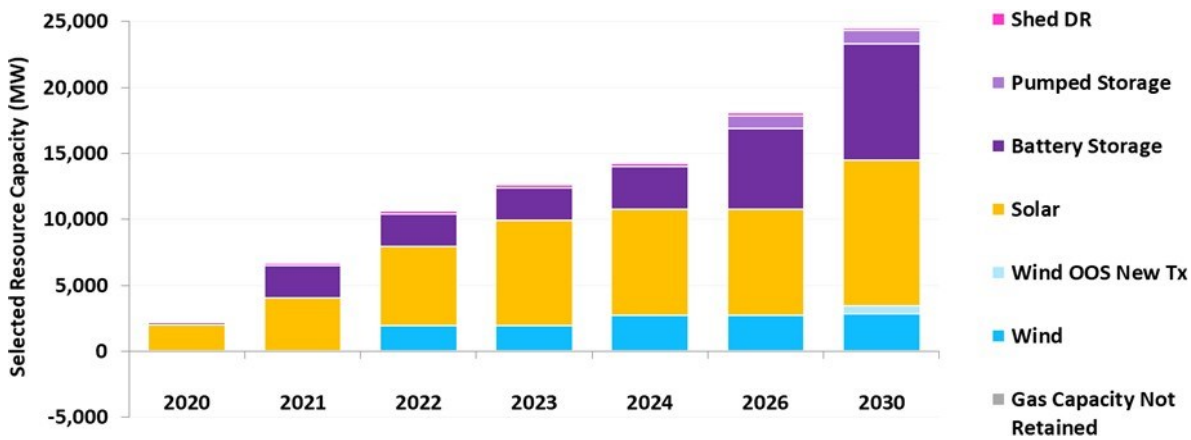
System and local reliability needs historically identified in Long Term Procurement Planning (LTPP) proceedings were specific to the transmission access charge (TAC) area of each IOU, and as such, CAM allows an IOU to allocate the net capacity costs and benefits of certain new generation resources to all customers of CPUC jurisdictional LSEs who are located within the IOU's TAC area.

In 2016, D.16-06-042[14] transferred LTPP functions to the joint Integrated Resource Planning and Long Term Procurement Planning (IRP-LTPP)) proceeding, R.16-02-007 and now R20-05-003. IRP-LTPP is an "umbrella" proceeding that will consider all of the Commission's electric procurement policies and programs and ensure California has a safe, reliable, and cost-effective electricity supply. The IRP is also the primary proceeding for implementation of the requirements of Senate Bill (SB) 350 (de León, 2015),[15] which are codified in PUC Sections 454.51 and 454.52.

SB 350 requires the CPUC to focus energy procurement decisions on reducing greenhouse gas (GHG) emissions by 40 percent by 2030. This includes efforts to achieve at least 50 percent renewable energy procurement, doubling of energy efficiency, and promoting transportation electrification. It also requires the CPUC's to ensure that LSEs meet targets that allow the electricity sector to contribute to California's economy-wide GHG reduction goals.

In the recent IRP Decision D.20-03-028, the CPUC adopted a 2019-2020 Reference System Portfolio (RSP), of 46 Million Metric Tons (MMT). The adopted RSP that is meant to guide procurement planning efforts necessary to achieve SB 350 GHG reduction goals. All load-serving entities that are required to participate in the Commission's IRP process, are required to file individual IRPs plans addressing their proportional share of the RSP. The decision requires LSEs to also file a second conforming portfolio to meet the 38 MMT portfolio, and they have option of to submit an alternative portfolio, if desired.

Figure 1. Cumulative Buildout of New Resources in 2019 – 2020 RPS



The IRP process takes into account forecasted energy consumption and energy production to meet reliability needs in addition to planning for future GHG reductions on the system. While the IRP process takes into consideration individual LSE capacity procurement in considering reliability needs and whether more generation needs to be built, it does not take into consideration whether LSEs have also secured forward energy to meet those reliability needs. The model assumes that if the resource is under an RA contract, then the energy associated with the resource will be available to the market. The model predicts energy production of resources using a set of production curves that are driven by economic dispatch assumptions, and the assumed dispatch levels of the resources are what drive the outcome of the RSP. However, there is no link between modeled energy production and contracted energy. The models assume that all resource that are online or contracted to be built will be bid and dispatched economically by the market.

It should also be noted that in November 2019, the CPUC addressed the potential for electricity system resource adequacy shortages beginning in 2021 by issuing D.19-11-016. In this decision, the CPUC recognized the tightening of supply on the system and the need for additional capacity to meet near-term reliability needs. D.19-11-016 ordered 3,300 MW of additional RA capacity to be procured by all LSEs and recommended the extension of gas fired generation units that utilize once through cooling technologies, to remain online and available to the market to serve as a bridge to meeting the reliability needs from 2021-2023.

D. CAISO's RA Enhancement Initiative

CAISO, in its current RA enhancements initiative, is proposing to look at reliability on a more granular basis. Rather than just looking at peak requirements, CAISO proposes enhancements that aim to ensure effective procurement of capacity to reliably operate the grid all hours of the year. CAISO is specifically proposing to perform a monthly portfolio assessment that will look at hourly needs in evaluating the aggregate monthly RA fillings (which are filed 45 days prior to the compliance month). CAISO believes the proposed portfolio assessment is necessary to address the growing reliance on use- and availability-limited resources. CAISO specifically proposes to develop a stochastic production simulation model[1] that would assess the RA fleet's ability to reliably operate the grid under a variety of conditions. If aggregate RA plans (RA portfolio) fail to meet forecasted hourly energy needs for the month (or other determined reliability criteria), CAISO will issue a collective deficiency notice and provide a cure period. If the deficiency is not cured CAISO will conduct backstop procurement to resolve the deficiency.

In its fifth revised straw proposal, CAISO states that it considered assessing individual LSEs showings for the portfolio assessment but found it was not feasible to develop individual LSE load profiles and determine how each LSE load profile contributes to a collective deficiency. CAISO states that it "supports, and is committed to, working with the [Local Regulatory Authorities] (LRAs) to establish up-front procurement requirements, similar to the CPUC's MCC buckets to help ensure collective procurement of a resource portfolio with the best possibility of passing the portfolio assessment." [2]

Additionally, CAISO proposes to continue with its 24 by 7 day-ahead MOO (unless the resource is on outage or exempt). In response to stakeholder's concern suggesting the 24 by 7 MOO does not align with the future makeup of the RA fleet (in which many resources will have use- or availability-limitations), CAISO states that

> [w]hile the makeup of the resource fleet is becoming increasingly use- and availability-limited, the CAISO believes most resources should still bid into the day-ahead market for all hours the resource is not on outage. A resource should have bids in all hours it is available, such that the day-ahead market can determine when the resource is needed over the course of the day and schedule it appropriately.[3]

The CAISO believes that modifying the MCC buckets would more appropriately address the increased amounts of availability-limited resources on the system, rather than modifying the day-ahead 24 by 7 MOO. CAISO asserts that redefining the MCC buckets couples with a 24 by 7 MOO into the day-ahead market "could be beneficial because resources with limited availability could contribute to RA needs consistent with their energy limitations, while still providing the CAISO market the ability to determine the hours the resource is needed over the course of the day. Additionally, this approach would benefit LSEs by providing more guidance into resource attributes needed to increase the possibility of passing the portfolio assessment, as discussed in Section 4.1.3.[4]

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[1] Building off the stochastic model usedin its "Summer Loadsand Resources Assessment" study
[2] CAISO's Fifth Revised RA Enhancements Straw Proposal at 42.
[3] CAISO's Fifth Revised RA Enhancements Straw Proposal at 45-46
[4] CAISO's Fifth Revised RA Enhancements Straw Proposal at 46.

D. CAISO's System Market Power Initiative

CAISO is also in the process of examining potential system market power mitigation in its real-time and day-ahead markets, in response to requests from its Department of Market Monitoring (DMM), IOUs and other stakeholders. These requests were primarily driven by high price events that occurred in 2017 and 2018 and findings that the market may not have been structurally competitive in a number of hours in those years. In its current draft final proposal, CAISO proposes only to consider system market power mitigation in the real-time market and to defer consideration of implementation in the day-ahead market until later initiatives, possibly concurrent with development with the extended day-ahead market, which may not occur until 2023.

In its current proposal, CAISO proposes only to assess for system market power if the following conditions are met:

- The CAISO balancing authority area's marginal energy cost is greater than $100/MWh.
- The CAISO balancing authority area's marginal energy cost is greater than the highest day-ahead bilateral electrical trading hub index price for the applicable operating day plus 10 percent. This price will be shaped hourly to convert the multi-hour index prices to hourly prices.
- The CAISO balancing authority area's marginal energy cost is greater than an energy price calculated based on current natural gas prices. This will be based on a CAISO proxy cost calculation of the costs of a hypothetical gas-fired peaker based on current gas costs plus 10 percent.
- The CAISO balancing authority area's marginal energy cost is the highest marginal energy cost in the Energy Imbalance Market (EIM) and is higher than other EIM balancing authority area marginal energy costs.

CAISO's also proposes the following:

- to use bids potentially available in the hour ahead scheduling process, which is a larger pool than is available in real-time,
- to assume all imports bids are fringe supply (and cannot exercise market power),
- to only mitigate offers for internal supply (not for any imports), and
- to mitigate internal pivotal suppliers' offers to the higher of their default energy bid, the next higher Energy Imbalance Market (EIM) offer, or any of the trigger prices listed above.

III. System Reliability Issues

The 2000 – 2001 California energy crisis had numerous causes, some of which were attributed to flawed market rules, inadequate generation, decreases in available hydro power, gas pipeline supply issues, high demand, and market manipulation. In addition, the path out of the energy crisis included decreased reliance on the spot market, execution of long-term contracts, new generation, and price caps (on the order of $250 per megawatt hour (MWh)).

As the state retires gas-fired generation, and with the emergence of retail choice, Energy Division staff are concerned that load serving entities may not have sufficient incentive to build new resources, sign long-term contracts, or to hedge their forward positions. These trends could detrimentally affect market conditions, especially in light of the movement towards reliance on intermittent resources and RA only contracts, combined with insufficient market power mitigation (e.g., the price cap in CAISO's market is increasing from $1,000 per MWh to $2,000 per MWh and system market power mitigation does not yet exist, as the western electricity market is assumed to be competitive).

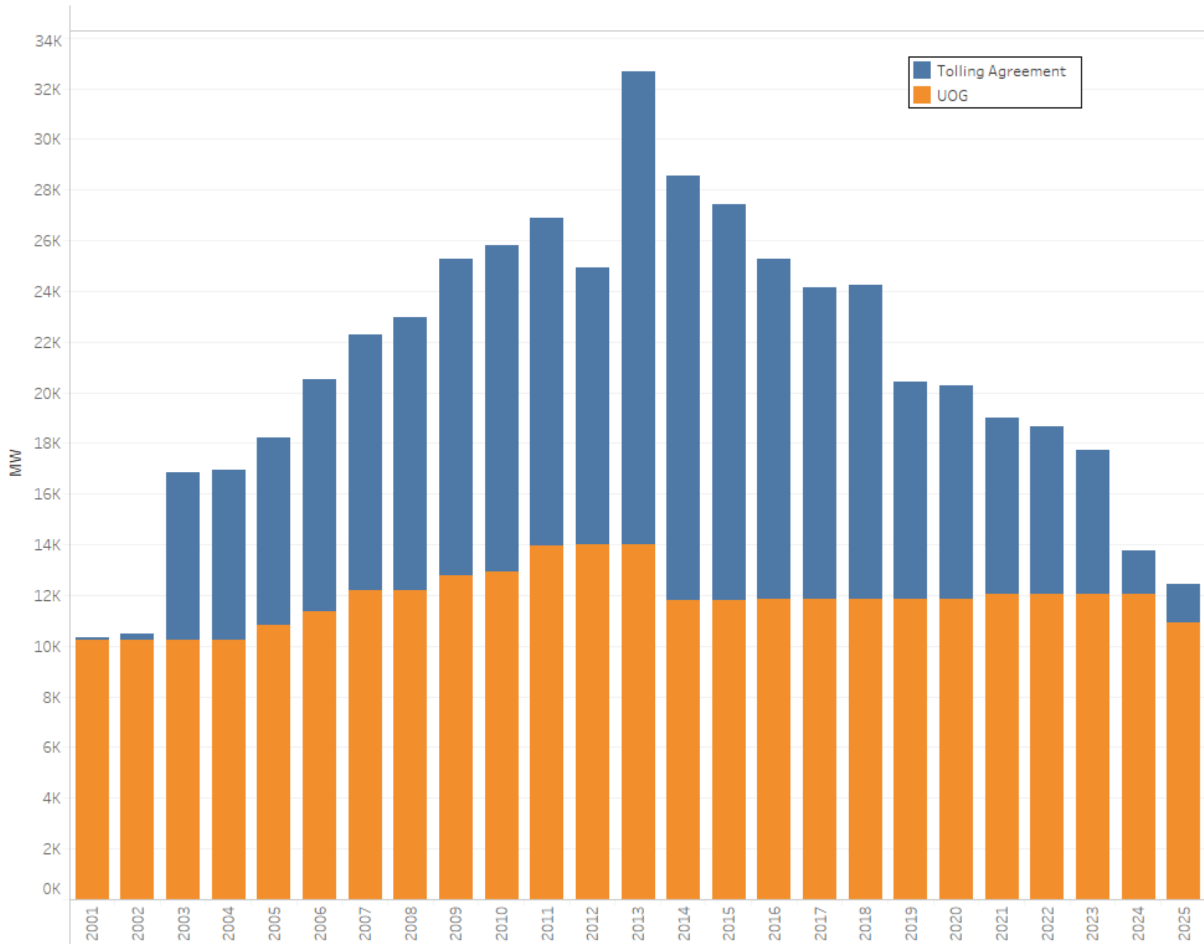
The following sections explore these topics in more detail, not necessarily in the order discussed above.

A. Long Term Tolling Contracts, RA Only Contracts, and Potential Effects on the Market

In the decade following the energy crisis, IOUs served much of the load in their service territories and executed long-term contracts for new resources and in many cases signed "tolling agreements" for much of the gas-fired generation under contract. Figure 2 illustrates the decline in tolling arrangements with, primarily, the gas resource fleet. This data shows all gas tolling agreements and DWR contracts (tolling or non-tolling) in place in 2006 or executed since 2006.

The blue bars in Figure 2 reflect resources that have been procured by the IOUs on behalf of bundled customers in addition to the resources that have been procured by the IOUs on behalf of all customer (CAM resources). With the exception of DWR contracts, only resources that have a tolling arrangement are included. The orange bars reflect the amount of UOG, which is mainly comprised of gas, hydro and nuclear resources. Taken together, these MWs amount to approximately 32,000 MWs of capacity in 2013 that were under the dispatch control of the IOUs and therefore subject to least-cost-dispatch requirements. By 2025 this number will have dropped to ~12,000 MW (which still includes the last unit of Diablo Canyon).

Figure 2. IOU Tolling Agreements and Utility Owned Generation



For both tolling agreements and UOG resources, the IOUs served as the scheduling coordinators and bid these resources into the CAISO market consistent with least-cost dispatch rules. Moreover, the CPUC has reviewed (and continues to do so) the IOU bidding for and dispatch of these resources through annual proceedings, thus ensuring that these (and, in fact all resources under their control) are bid into the market with marginal cost-based bids. In many ways, this has ensured that the energy market has a deep pool of marginal cost-based bids and that the "competitive" outcome does not reflect market manipulation or the exercise of market power.

However, the number of these types of contracts has declined in the last decade and additional tolling arrangements will fall off in the coming years. Given that the IOUs have lost load to ESPs and community choice aggregators (CCAs) and are uncertain about load migration in the future, the IOUs have little incentive to resign long-term tolling arrangements to serve just their bundled service customers. Likewise, policymakers and regulators have indicated their intent to move the state away from reliance on gas-fired generation, making it less likely that these long-term tolling arrangements will be extended. In addition, it is not clear that ESPs are large enough or have adequate certainty regarding load to sign long-term tolling agreements with large gas-fired generators or that it is consistent with the business model of most CCAs to sign such agreements. Finally, given that many entities in the current California market compete on their ability to provide “green” power and the California Energy Commission’s power content label (PCL) requirements dictate that load serving entities report emissions from tolling agreements on their PCL, there is a general reluctance to resign these contracts in the current market, unless the emissions are allocated to all customers.

The CPUC addressed this issue to some degree in its local central procurement entity (CPE) decision (D.20-06-002), which designated SCE and PG&E to be the CPEs responsible for all local procurement in their respective service areas. Specifically, the decision requires that the CPE’s solicitation include dispatch rights (or other means that stipulate how resources will bid into the energy markets) as an optional term. If the CPE is successful in procuring these dispatch rights, then some of the local gas tolling arrangements falling off of contract in the coming years could be procured by the CPE to include dispatch rights (or other means that stipulate how the resource will bid into the energy markets). If the IOU is the scheduling coordinator for these resources than it must ensure that these resources are bid into the market consistent with least-cost dispatch principles. Further, having the CPE will allow for longer-term contracts, which could provide certainty for generators and customers, help to address load migration, and mitigate market power issues in the local capacity areas, which CAISO’s DMM has determined are structurally uncompetitive.

Nonetheless, serious market concerns remain. As discussed, because tolling or energy deals with gas generators require the LSE to retain the gas emissions attribute for power content label reporting purposes, many LSEs including the IOUs are signing “RA-only” deals, where the bidding is left to the generator. These RA-only contracts are not subject to least-cost dispatch requirements, nor subject to any system market power mitigation by CAISO (system market power mitigation does not currently exist, though mitigation measures are being proposed for the real-time market, perhaps for the summer of 2021, if not opposed at the FERC by stakeholders to CAISO’s current process).

This issue is important because there is some anecdotal evidence that net buyers (e.g., IOUs) bid into the market differently than net sellers (e.g., generators without load), as shown in Figures 3 and 4 below. In particular, on a high load and high price day on July 24, 2018, hour ending 20, CAISO’s DMM illustrates in its 2018 annual report (Figure 3) that the bids from net buyers were less frequently above their default energy bid (DEB), which themselves have adders to account for uncertainties associated with fuel and other costs. That is, bids for resources totaling ~1,500 MW were bid above the DEB, out of ~7,500 MW of bids submitted by net buyers in this hour. By contrast Figure 4, reflects that net sellers much more frequently bid above their DEBs than net buyers – that is, bids for resources totaling ~4,500 MW were above the DEB, out of ~10,000 MW of bids submitted by net sellers in this hour. This issue bears further scrutiny and Energy Division staff will endeavor to obtain more recent data, should the schedule for examining broader issues associated with the RA market be extended, as discussed in Section V.

Figure 3. Net buyers supply input bid and reference, July 24, 2018 hour 20[5]

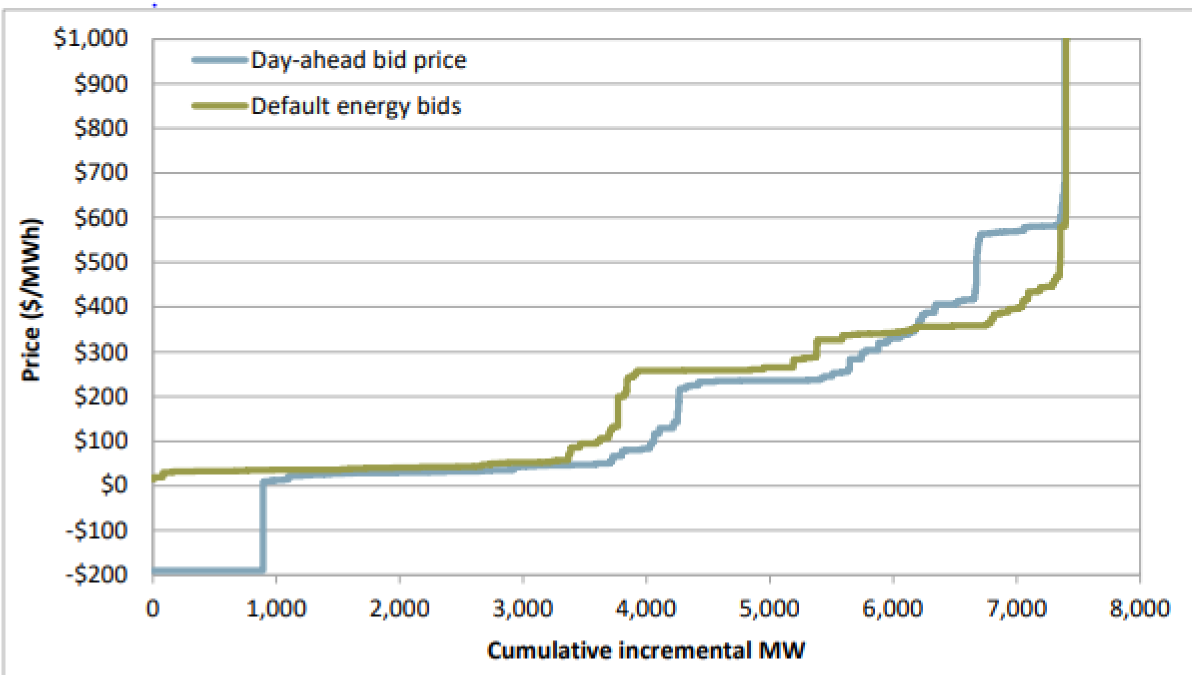
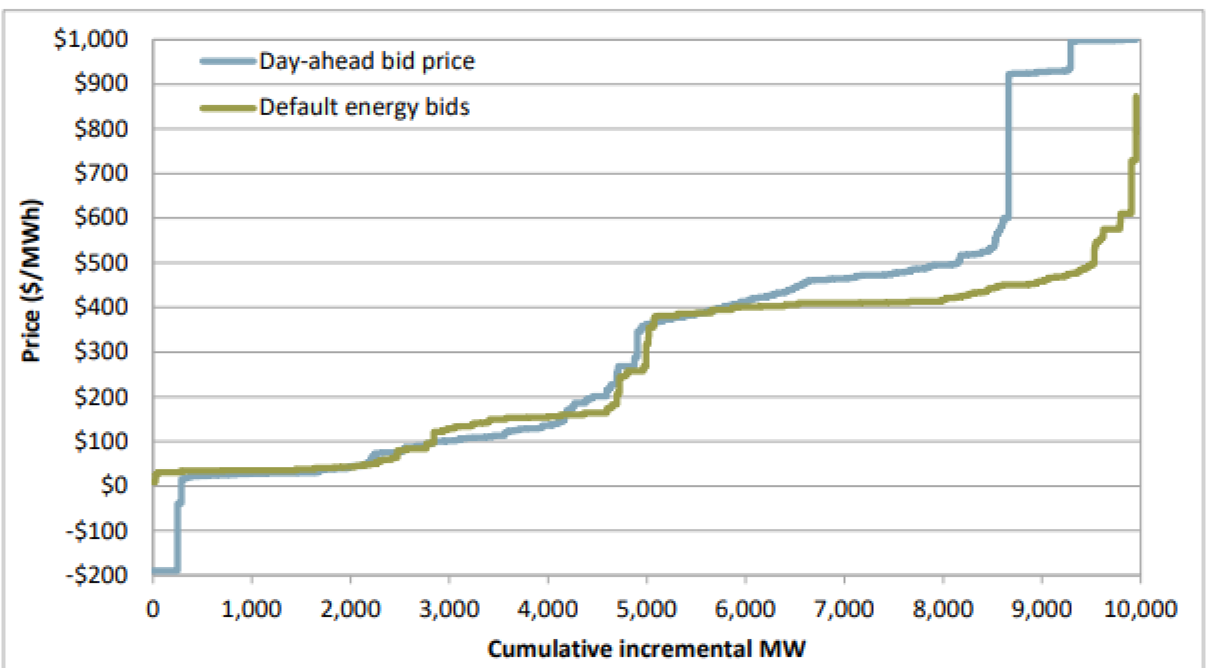


Figure 4. Net sellers supply input bid and reference, July 24, 2018, hour 20[6]



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[5] CAISO, 2018 Annual Report on Market Issues & Performance, p. 153, available at http://www.caiso.com/Documents/2018AnnualReportonMarketIssuesandPerformance.pdf

[6] Ibid.

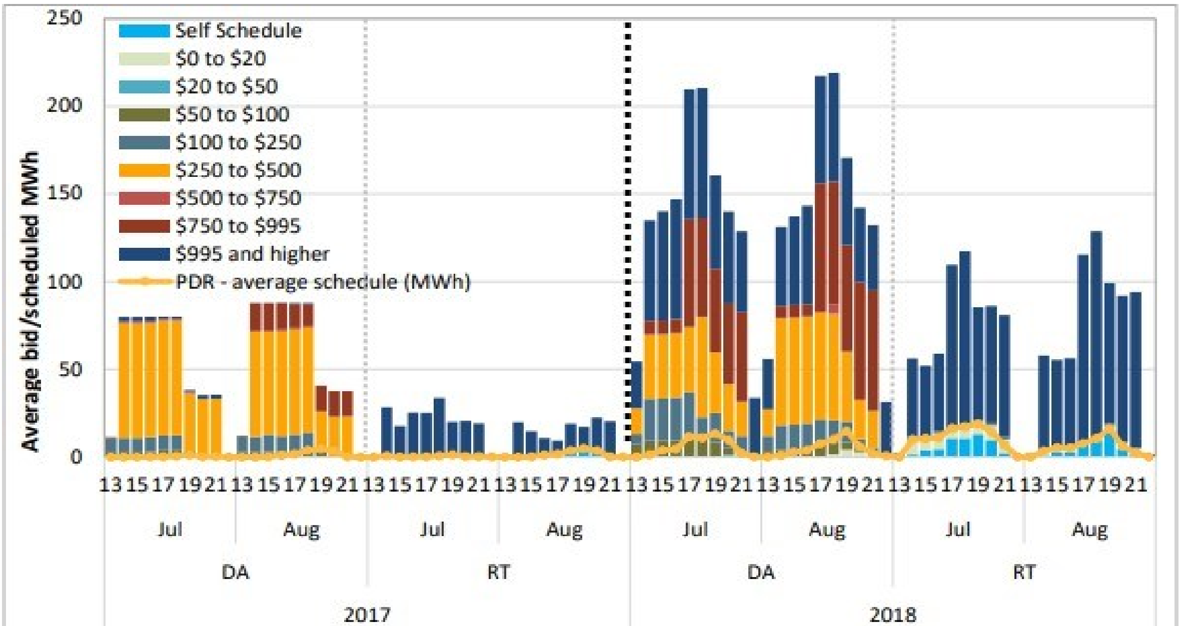
Further, there is some evidence that under RA-only contracts, some types of resources are bidding to ensure that the resource is *not* dispatched (i.e., bidding above the expected market clearing price and up to the current $1000/MWh cap) – contrary to the notion that resources should bid into the market economically (i.e., based on marginal cost principles). This issue was explored and discussed with respect to import RA in the previous RA rulemaking, R. 17-09-020, in the Energy Division staff report on imports released February of 2020, and in two decisions released by the CPUC – D.19-10-021 and D.20-06-028. Of note, in September 2018, DMM issued a special report on RA imports expanding upon its earlier analysis and found that:

> …[D]uring peak hours in July and August of 2018, an average of about 484 MWh of imports used to meet resource adequacy requirements was bid in the day-ahead at prices greater than $750/MWh, compared to an average of around 145 MWh in the summer of 2017. None of the resource adequacy imports bid over $750/MWh ever cleared in the day-ahead market.[7]

In addition, there is emerging evidence that a growing amount of third-party proxy-demand response resources are similarly bidding at levels that ensure the resource is *not* dispatched in the market – effectively operating in a manner similar to reliability demand response, which is typically bid into the market at close to the bid cap, currently set at $1000/MWh, and rarely used in the market. These DR products were initially proposed and developed based on the assumption that they would seek rents from the energy market and/or bid at marginal cost, but many third-party providers appear not to be doing so.

[7] DMM, Special Report: Import Resource Adequacy(September 10, 2018) at 1-2.

Figure 5. CAISO 2018 Annual Report -- Proxy Demand Response Bid Prices and Average Schedules July and August (HE 13 – 22)[8]



Continued and growing reliance on resources intending not to dispatch in the market raises two problems. First, this raises reliability issues if the capacity is needed to meet load and does not generate (in the case of imports) or does not respond (in the case of demand response or other resources bidding at or near the bid cap). Second, this could result in exceptionally high prices, if increasing numbers of use-limited or other resources are bidding at the cap, thus making it more likely that the market will clear at high prices, if not at or near the cap itself.

The CPUC has attempted to address the issue of imports in its recent decision (D.20-06-028), but Energy Division staff remain concerned that LSEs and import providers are structuring complex contracts in an attempt to evade the essence of the requirement – that non-resource specific resources include energy to be delivered to California (and to the load serving entity itself) during the net peak hours when the system is most stressed and when prices typically peak in California. In addition, the CPUC addressed the DR issue to some extent by limiting the amount of DR any particular load serving entity could use to show that it meets its RA requirements (D.20-06-031), but concerns in this area still remain.

Some stakeholders may argue that this issue is moot, since energy prices were low in 2019. However, staff note that weather was mild and load was moderate in 2019, and hydro resources were abundant; looking toward the future, conditions are expected to change in California and throughout the West. Notably, the remaining gas-fired once through cooling facilities, which comprise thousands of MWs, are

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[8] CAISO DMM 2018 Annual Report, p. 43, available at http://www.caiso.com/Documents/2018AnnualReportonMarketIssuesandPerformance.pdf

expected to retire in the next several years; California last operating nuclear generation facility, Diablo Canyon, with 2,000 MW of baseload capacity, is also scheduled to retire in 2024 and 2025; and the Western market is expected to tighten as summer loads grow in the Western region and large coal facilities potentially retire.

Further, staff notes that price spikes are beginning to occur, especially between 7 – 8 pm, (HE 20), even during fairly moderate loads (e.g., 40,000 MW). For example, on July 30, 2020, when California load reached 39,760 MW -- compared to a normal peak load of 45,000 MW, which California typically sees each year -- prices reached $245/MWh during HE 20 in the day-ahead market. Further, prices in excess of the $1000/MWh bid cap occurred in both CAISO's 15-minute market (see figure below) and the 5-minute market for this hour as well.

Figure 6. CAISO Demand Trend, July 30, 2020

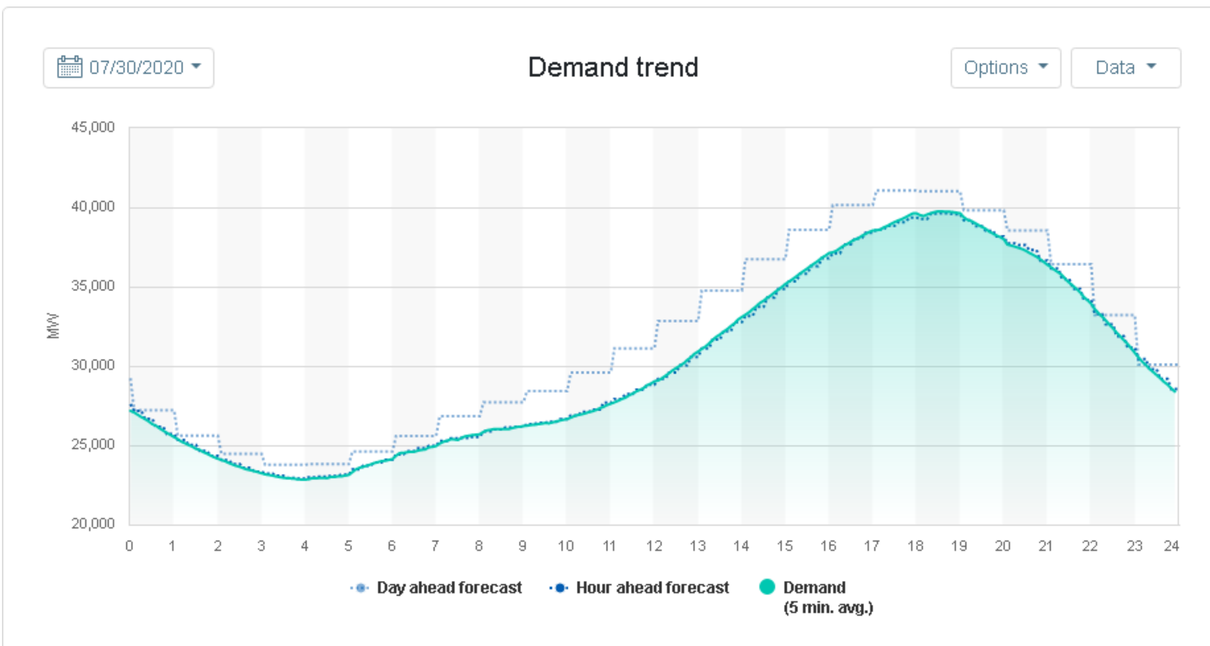


Table 3. Fifteen Minute Local Marginal Prices, July 30, 2020, Hour Ending 20

Date From: 07/30/2020 To: 07/30/2020 Group Type SELECT_NODE Node 3 item(s)

Download XML Download CSV

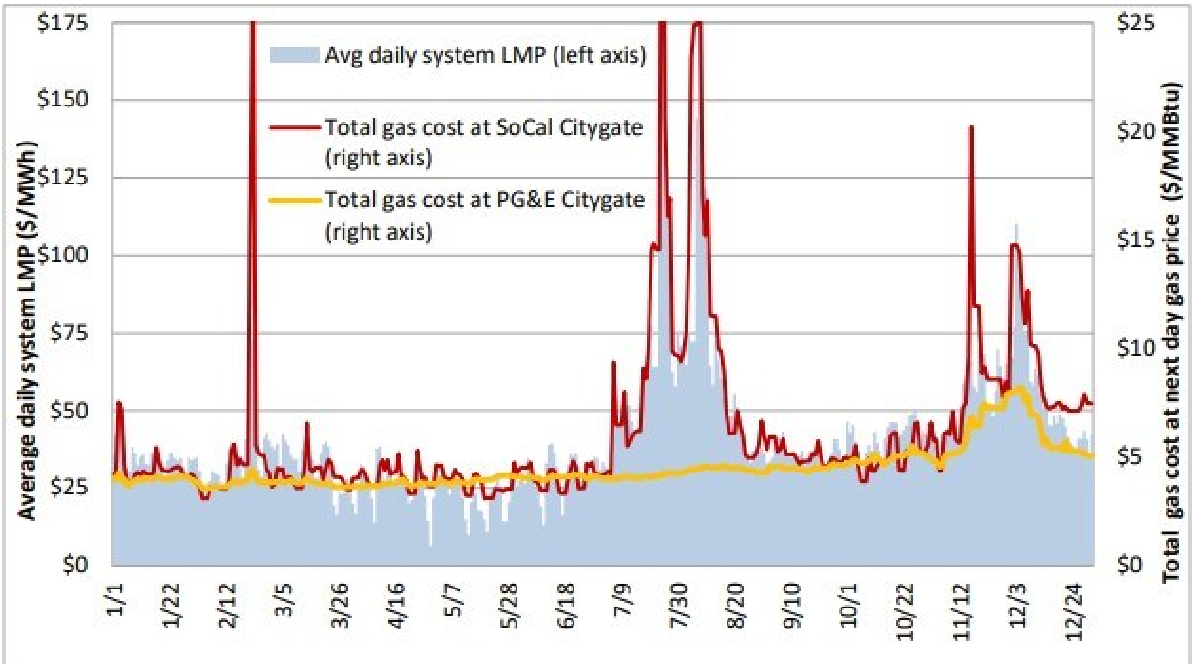
FMM Locational Marginal Prices (LMP)

1 - 15 of ???

Market	Opr Date/Hour	Node	LMP Type	INTERVAL01	INTERVAL02	INTERVAL03	INTERVAL04
RTPD	07/30/2020 - Hour Ending 20	DLAP_PGAE-APND	LMP	251.28651	370.47750	827.88440	551.06555
RTPD	07/30/2020 - Hour Ending 20	DLAP_PGAE-APND	Congestion	-514.20856	-592.04280	-316.42737	-577.68490
RTPD	07/30/2020 - Hour Ending 20	DLAP_PGAE-APND	Energy	765.49506	962.52030	1,144.31180	1,128.75050
RTPD	07/30/2020 - Hour Ending 20	DLAP_PGAE-APND	Loss	0.00000	0.00000	0.00000	0.00000
RTPD	07/30/2020 - Hour Ending 20	DLAP_PGAE-APND	Greenhouse Gas	0.00000	0.00000	0.00000	0.00000
RTPD	07/30/2020 - Hour Ending 20	DLAP_SCE-APND	LMP	1,185.49740	1,450.86410	1,406.18270	1,609.42000
RTPD	07/30/2020 - Hour Ending 20	DLAP_SCE-APND	Congestion	420.00240	488.34378	261.87094	480.66960
RTPD	07/30/2020 - Hour Ending 20	DLAP_SCE-APND	Energy	765.49506	962.52030	1,144.31180	1,128.75050
RTPD	07/30/2020 - Hour Ending 20	DLAP_SCE-APND	Loss	0.00000	0.00000	0.00000	0.00000
RTPD	07/30/2020 - Hour Ending 20	DLAP_SCE-APND	Greenhouse Gas	0.00000	0.00000	0.00000	0.00000
RTPD	07/30/2020 - Hour Ending 20	DLAP_SDGE-APND	LMP	1,169.79650	1,429.41980	1,395.27140	1,588.34050
RTPD	07/30/2020 - Hour Ending 20	DLAP_SDGE-APND	Congestion	404.30140	466.89950	250.95964	459.59000
RTPD	07/30/2020 - Hour Ending 20	DLAP_SDGE-APND	Energy	765.49506	962.52030	1,144.31180	1,128.75050
RTPD	07/30/2020 - Hour Ending 20	DLAP_SDGE-APND	Loss	0.00000	0.00000	0.00000	0.00000
RTPD	07/30/2020 - Hour Ending 20	DLAP_SDGE-APND	Greenhouse Gas	0.00000	0.00000	0.00000	0.00000

While this is merely anecdotal evidence that considerable price spikes in the CAISO market can occur, it serves as a warning of what could occur in the future. Staff also notes that due to gas market issues associated with the partial closure of Aliso Canyon and other gas supply issues, energy prices spiked in 2018 and resulted in considerable cost to California ratepayers (see Figure 7 below).

Figure 7. DMM 2018 Annual Report -- Average Daily Price for Electricity and Natural Gas (2018)[9]



Further, due to FERC Order 831, the current $1,000/MWh price cap will increase to $2,000/MWh, likely in the fall of 2021, which could further exacerbate any pricing/cost issues that could arise. These high costs will be borne by California ratepayers. In addition, CAISO does not currently have any system market power mitigation measures in place, noting that it and FERC assume that the Western energy market is workably competitive. However, in response to stakeholder requests, CAISO is currently considering system market power mitigation, but only in the real-time market in which only five percent of the bids clear and only under limited circumstances -- CAISO has proposed that it would only mitigate bids from sources internal to the CAISO system, and only if system market power is found. CAISO has indicated that it would examine system market power mitigation in the day-ahead market (where ~95 percent of the bids clear), but the timeline and the outcome of this effort is uncertain at this time.

B. Market Fragmentation and Provider of Last Resort

California first enabled DA in 1998, under AB 1890 (Brulte, 1996), but the CPUC suspended DA during the California energy crisis, pursuant to Decision (D.)01-09-060. In 2010, SB 695 (Kehoe, 2009) reopened DA to non-residential customers on a limited basis. Commission decisions D.10-03-022 and D.10-05-039 established a process for the limited reopening of DA, including an incremental cap of 8,354 gigawatt hours (GWh) – and a total cap of 24,792 GWh – within the three IOU service territories.[10] As a result of the caps, both the number of ESPs and the load served by ESPs has remained relatively stable since 2011. SB 237 (Hertzberg, 2018) required the Commission to establish a process for increasing the DA cap

[9] CAISO DMM 2018 Annual Report, p. 68, available at http://www.caiso.com/Documents/2018AnnualReportonMarketIssuesandPerformance.pdf.

[10] See D.10-03-022, Appendix 1 at 1 (available at https://docs.cpuc.ca.gov/PublishedDocs/WORD_PDF/FINAL_DECISION/114976.PDF).

by 4,000 GWh. D.19-05-043 and D.19-08-004 established these procedures, with the cap set to increase beginning in 2021.

Assembly Bill 117 (Migden, 2002) established the process of community choice aggregation in California. The first CCA began serving load in 2010, and the number of CCAs has expanded rapidly since 2015. There are currently 21 CCAs serving load as of August 2020, and there will be 22 serving load by the end of the year. Energy Division anticipates that 26 CCAs will be serving customers by the end of 2021.

The table below shows the growth in the number of LSEs from 2008 through 2021, including approved and pending implementation plans.

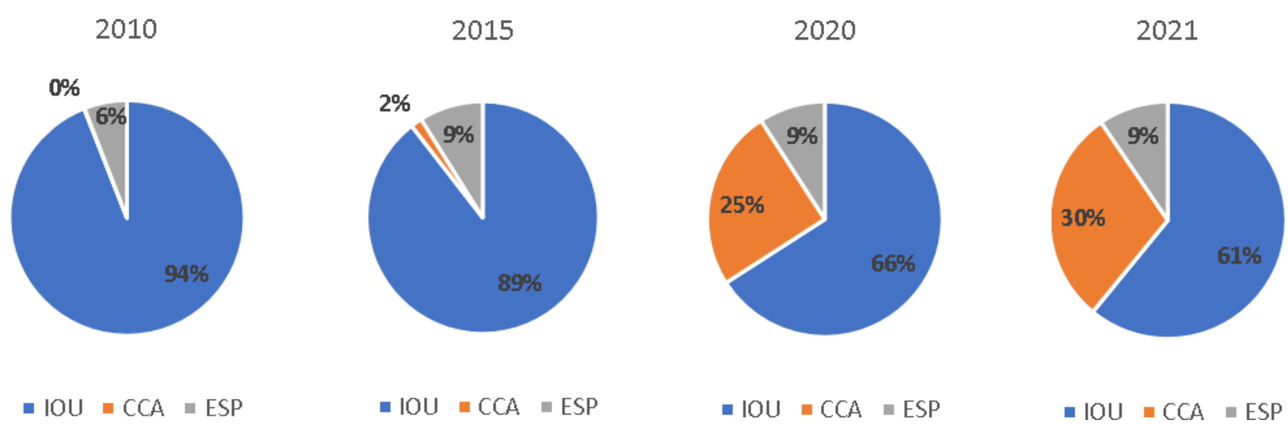
Table 4. Number of LSEs, 2008 - 2021

LSE Type	2008	2009	2010	2011	2012	2013	2014	2015	2016	2017	2018	2019	2020	2021
IOU	3	3	3	3	3	3	3	3	3	3	3	3	3	3
ESP	12	10	9	13	12	14	14	15	14	14	14	14	13	13
CCA	0	0	1	1	1	1	2	3	5	9	19	19	23*	26
Total	**15**	**13**	**13**	**17**	**16**	**18**	**19**	**21**	**22**	**26**	**36**	**36**	**39**	**42**

* 8 new CCAs were approvedto start operating in 2020 (bringing the total to 25) and had filed 2020 Year Ahead RA forecasts. Of these, one subsequently deregistered as a CCA, one informed Energy Division that it would delay until 2022, and two informed Energy Division that they would delay indefinitely.

The figure below depicts the peak load forecast by LSE type in 2010, 2015, 2020, and 2021. These numbers represent both the increase in the the number of LSEs serving load, as well as increases in the number of customers served by existing LSEs (e.g. through CCA territory expansion).

Figure 8. Peak Monthly Forecast* by LSE Type, 2010 - 2021



*Data are from Month Ahead forecasts, except for 2021, which uses adusted initial Year Ahead forecasts. The peak month for 2010 and 2015 was August, and the peak month for 2020 and 2021 is September.

The key issues with market fragmentation are, at least, threefold:

- First, it makes it difficult to build new resources needed to reliably operate the grid, if entities do not know whether they will be serving load in the future. In the past, the CPUC used the IOUs to build needed reliability resources and allowed the IOUs to allocate these costs on a non-bypassable to all customers. Recently, the CPUC took a different approach in the November 2019 IRP procurement decision (D.19-11-016), allowing LSEs to opt in or out of new reliability procurement, but cost-allocation questions, and whether this will serve as a workable model for the future, remain.
- Second, since load is uncertain, it is less likely that entities will sign long-term contracts with new or *existing resources*. Many parties also argue that the IOUs should not undertake long- term procurement because reliance on gas resources is expected to decreasein the future and/or because they expect the IOUs will lose load to CCAs and ESPs. Further, many ESPs have indicated that they undertake little long-term procurement because it is not consistent with their business model, which is based one-year contracts with customers. Finally, staff's analysis indicates that long-term contracting is not occuring in ways consistent with prior IOU procurement practicies, which could be a major warning signal of future problems– as this leaves all customers exposed to price volatility if the market dynamics shift quickly. Moreover,coming out of the enegy crisis, long-term contracting was determined to be necessary in order to stablize the energy markets for the benefit of all customers.
- Third, if market fundamentals change, both CCAs and ESPs, can return customers to the IOU as the provider of last resort. The reliability and cost issue with this prospect is this – should prices in the capacity and/or energy market increase precipitously, as occurred during the energy crisis, the IOUs will not be hedged for the returning customers and could potentially need to pay high spot market prices, to the detriment of all customers and the stability of the market. Further, it is unclear if this is viewed as a cost-free option to CCAs and ESPs, which could lead them to underhedge – since the ability to return customers should adverse events occur, remains. Finally, this is not an idle issue. Last year, one ESP left the market and this year, another ESP has indicated it will not serve load in 2021. Further, one CCA has indicated that it will not likely launch and another has delayed its implemention date, despite both having submitted"binding" load forecasts for 2021 in April of 2020.

C. Increased Reliance on Use-Limited Resources and the Relationship with the MCC Buckets

In a variety of forums, the CPUC and the state have made it clear that they intend to move away from reliance on gas-fired resources, in order to address environmental concerns and meet 2030 and 2050 greenhouse gas reduction goals. As a result, much of the new generation that has come online in the past several years and is expected to be online in the near- and medium-term includes renewables, storage, and demand response. All of these resources, however, have significant use limitations – wind and solar depend on the weather, the storage resources that are online and expected to come online in the near future almost universally are sized to serve load for four hours, and demand response depends in large part on the preferences of the customers being paid to drop load. Moreover, as discussed above, significant resource retirements of gas and nuclear baseload facilities are expected in the next several years. As a result, Energy Division staff expect that issues associated with dependence on a suite of use limited resources to meet the state's reliability needs will become increasingly important.

Therefore, staff is concerned that the current MCC buckets structure may not be up to the coming challenge. MCC buckets are not currently binding, and staff has determined that a number of load serving entities have placed a significant amount of use-limited resources in Bucket 4, based on the presumption that the resource is "available" to bid 24 x 7 rather than having the physical capability to operate 24 x 7. As we have noted previously, it makes little sense for a load serving entities to use only batteries to meet their RA needs, since generation resources would be needed to charge the batteries.

In D.20-06-031 the Commission addressed MCC bucket compliance by stating:

> although enforcement of MCC buckets is a concern, it is unnecessary to institute additional filing requirements at this time. The Certification of Information on Energy Division's RA filing template covers MCC bucket categorizations, as well as other information in the filings. We authorize Energy Division to request additional documentation (including contracts) to verify LSEs' claims, as well as review bidding data to ascertain how particular resources are operating in the CAISO markets.[11]

Figure 9 reflects the 2019 and 2020 RA showings by resource bucket for September by resource type.

[11] D.20-06-031 at 50.

Figure 9. September RA Showings, Resource Type and MCC by Bucket

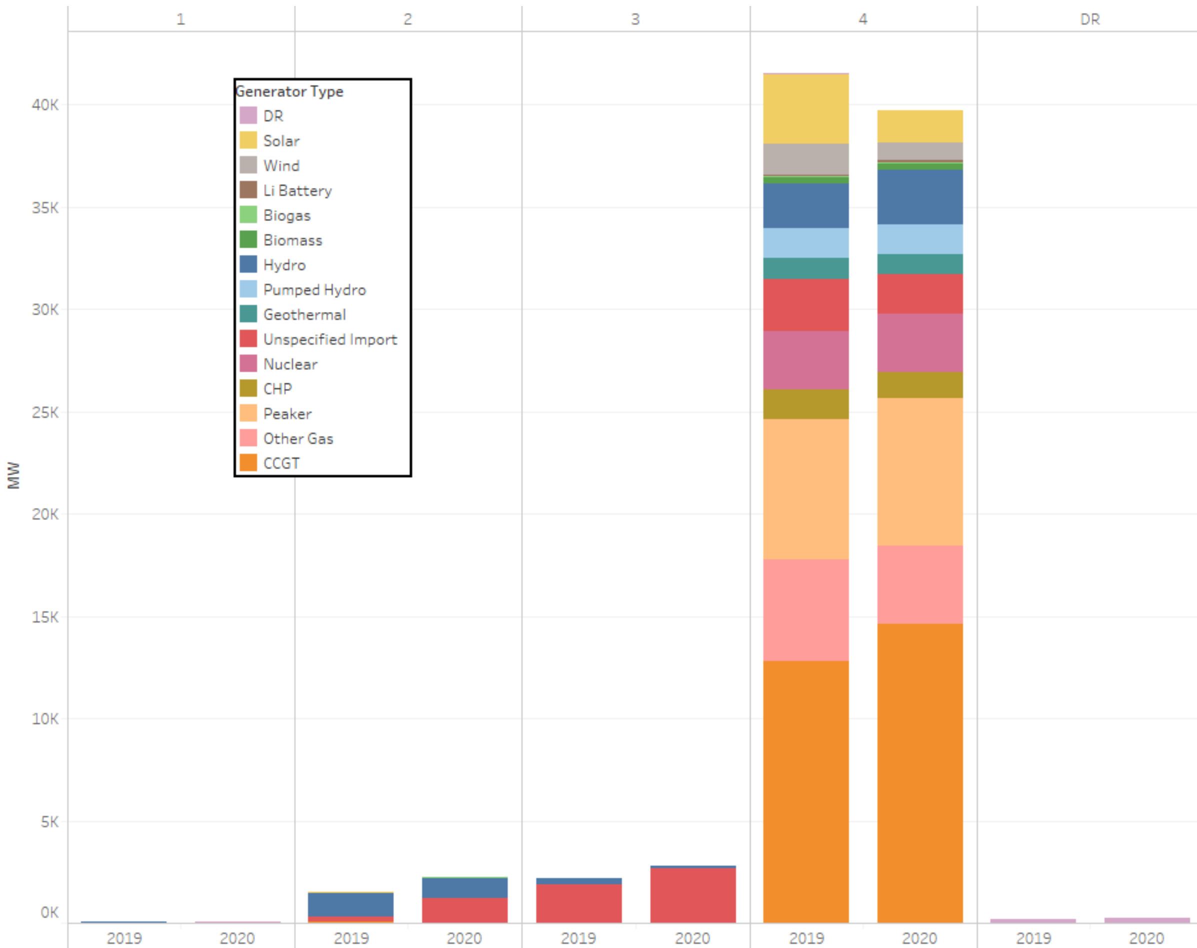


Figure 10, below, looks at just the 2020 September RA filings by MCC bucket and resource type across the use limitation flag in the CAISO Master File. As demonstrated in the figure below, the majority of resources with a use limited flag are reported in bucket 4. You can also see that the use limited flag is made up of approximately 50 percent gas and 50 percent hydro resources with the majority being categorized in bucket 4.

Figure 10. September 2020 RA Showings, by Bucket, with Use Limitation Flags

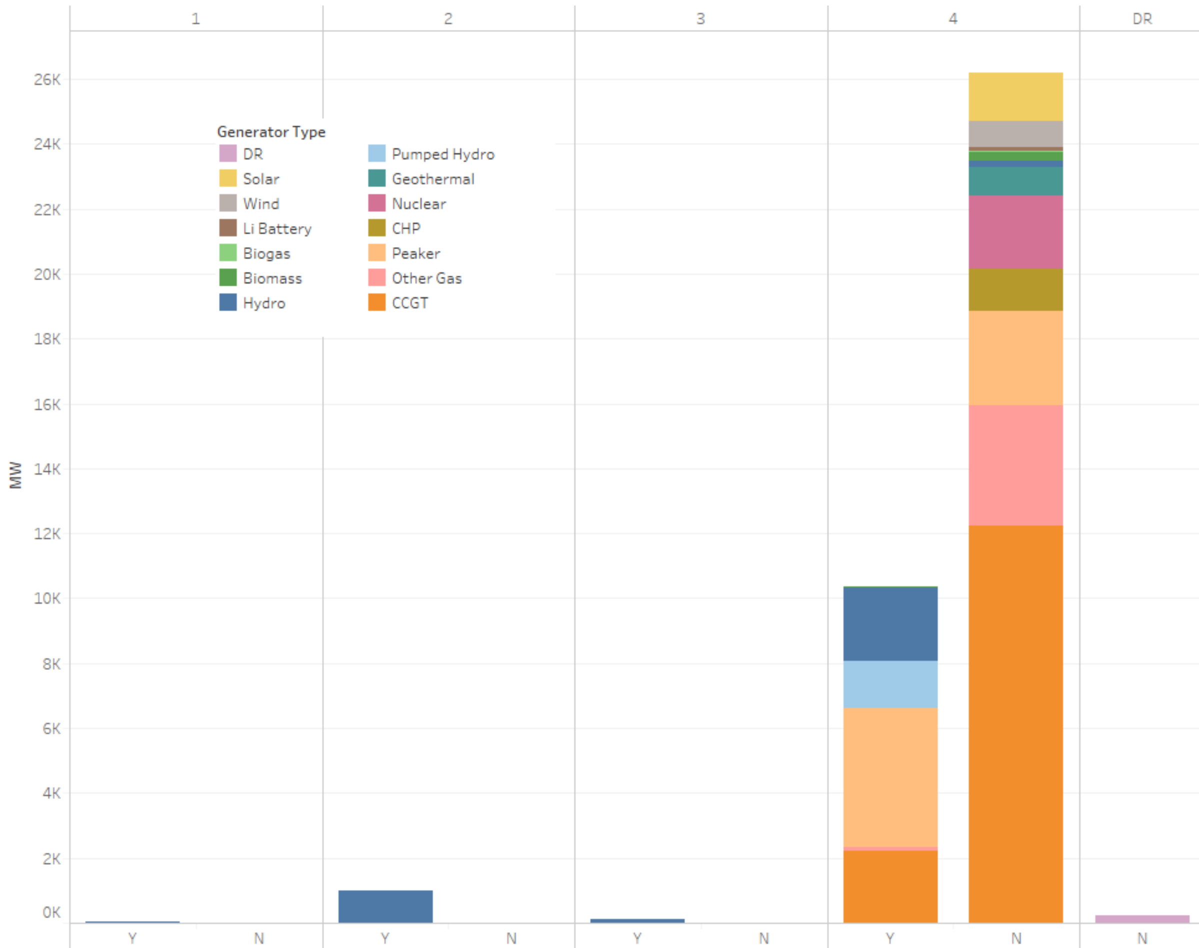
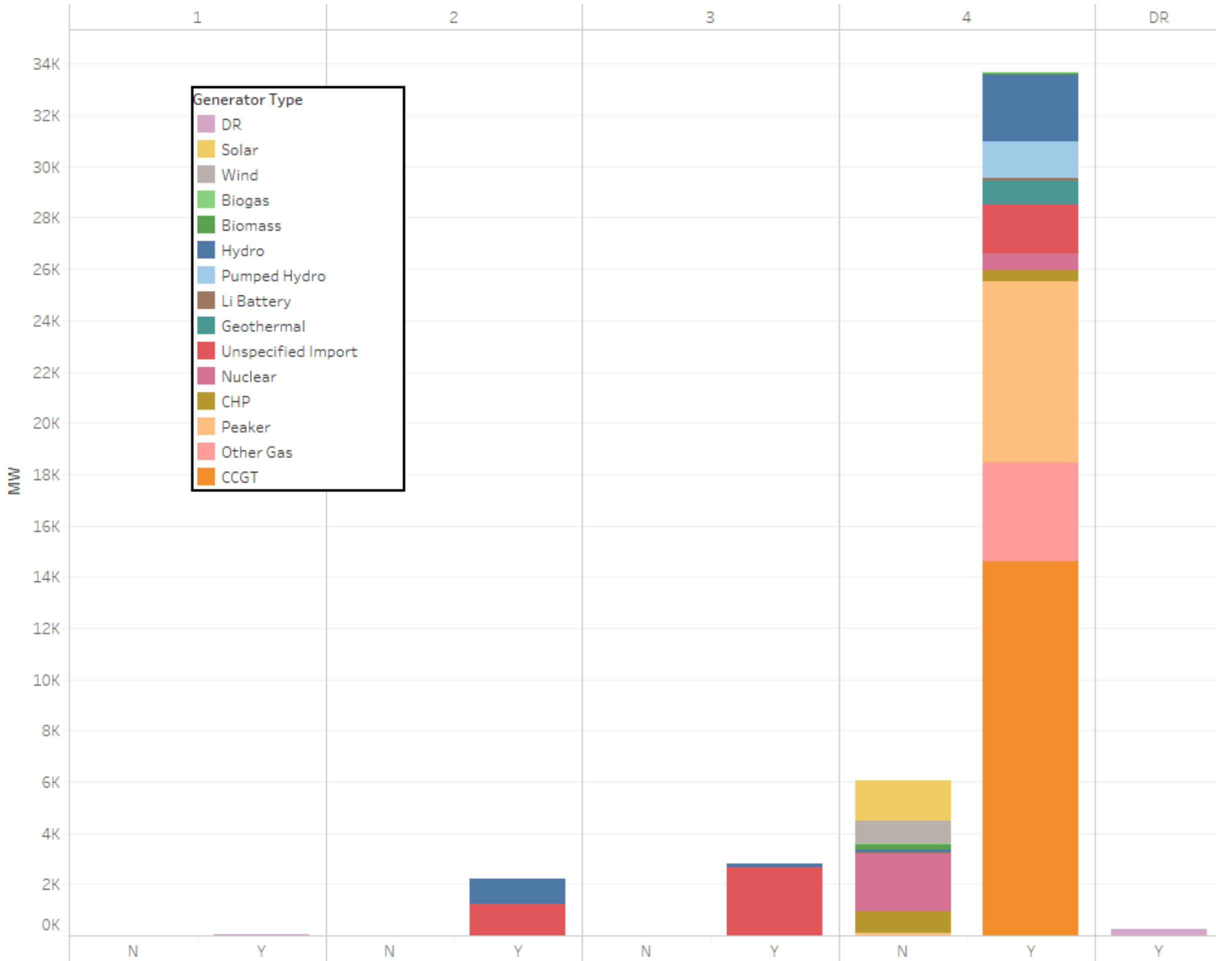


Figure 11 looks at the 2020 RA filings for September by bucket category and dispatchability status. This chart reflects that the majority of non-dispatchable resources are be categorized in bucket 4.

Figure 11. September 2020 RA Showings, by Bucket with Dispatchability Status



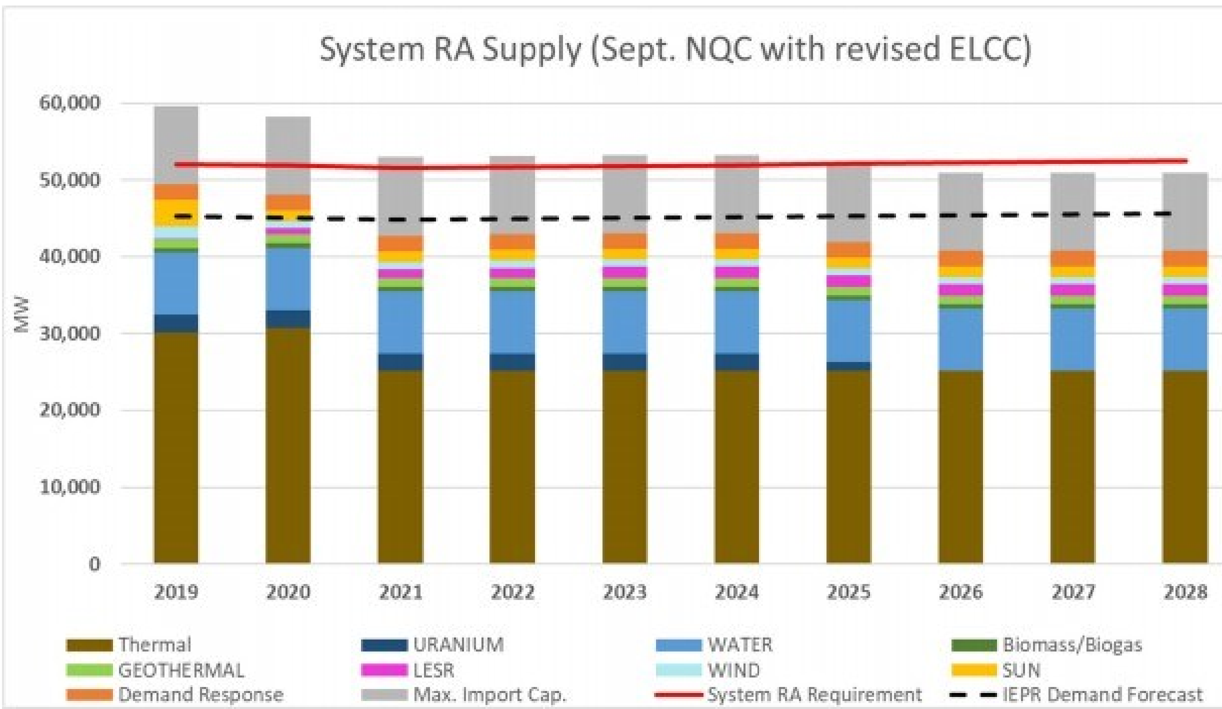
The data above demonstrate that most resources are categorized as bucket 4 resources. However, there are many use limitations on these resources that are not reflected in the way they have been categorized. MCC bucket categorization needs to be based on resource's physical capability as well as its availability to bid and self-schedule into CAISO markets. It is unclear what physical capability data should be used to categorize resources by bucket, however, it is clear that further clarification on the use of these buckets is needed to ensure they achieve their purpose of preventing over reliance on use limited resources in meeting system needs.

D. Tightening of Supply in California and Across the West

As discussed previously, due to the expected retirement of thousands of MWs of gas-fired once-through cooling resources and 2,000 MW of the nuclear facility, Diablo Canyon in 2024 and 2025, the supply picture is expected to tighten in California and could tighten further, given the uncertainty around the reliance on hydro resources. The CPUC has begun to address this issue, with the authorization of 3,300 MW of incremental RA capacity to be procured by load serving entities in California in the next three years, and is expected to monitor and authorize additional procurement through the Integrated Resource Planning process, should additional need arise. In addition, many parties and stakeholders have noted that the picture across the West is expected to tighten as well, as summer loads increase due to greater reliance on air-conditioning and as coal facilities potentially retire in the western market.

The California supply situation, although just a snapshot in time, is shown in the figure below (this figure does not include the proposed extension of the OTC facilities, nor the addition of the new resources authorized by the CPUC). As this figure illustrates, the supply/demand balance has tightened considerably, although this will likely be addressed in the near-term with the extension of the OTC units and the new resource requirements imposed by the CPUC.

Figure 12. System RA Supply from June 2018 Ruling[12]



This figure also illustrates that California is at least in part dependent on imports to meet summer peak loads. While typically large amounts of imports are assumed to be available and typically modeled in the state's resource planning, this assumption is increasingly being tested and bears further exploration. If this capacity is not indeed available as expected, California policy makers and planners will need to consider how to address this at some point in the nearfuture.

[12] Available at https://docs.cpuc.ca.gov/PublishedDocs/Efile/G000/M302/K942/302942332.PDF.

IV. Potential Options for Improving or Replacing the Current Reliability Construct

This section explores three potential solutions staff has identified that could address the emerging reliability and market power concerns described in Sections II and III. These interconnected concerns can be summarized as:

- Retirements outpacing new resource additions in recent years, on a net qualifying capacity basis, which has significantly reduced reserve margins, and the lack of forward contracting (e.g., through multi-year tolling agreements) creating the opportunity for the exercise of system and local market power, particularly in the energy and RA markets;
- The fact that "peak capacity" is a regulatory construct – it is not the actual flowing of electrons or the curtailment of demand, it is a paper commitment to do so – and consequently a contractual commitment to provide peak capacity can be speculative in nature and potentially unreliable;
- A growing reliance on use limited resources (e.g., renewables, hydroelectric, pumped storage, batteries and other storage devices, demand response, etc.), coupled with the retirement of substantial amounts of the gas-fired generation make it challenging to design a reliable hourly capacity construct;
- Growth in retail choice and the relationship with the provider of last resort makes it difficult to plan for reliability, if entities do not know whether they will be serving future load. This load uncertainty prevents entities from entering long-term contracts with new or existing resources; and
- Retirement of other assets throughout the West reduces the amount of imports that can be reliably counted on to serve California load during peak demand periods, which are often coincident throughout much of the West.

The three options staff have identified to address these concerns by modifying or replacing the existing peak capacity RA construct include:

(1) Making several fundamental modifications to the existing capacity construct including revising the MCC buckets to make them binding in order to address issues associated with use-limited resources and revising the RA product to include a least-cost dispatch requirement or a bid cap;

(2) Enhancing or replacing the current RA capacity / CAISO must-offer obligation construct with a forward energy based system hourly load shape framework that requires load serving entities to demonstrate procurement of sufficient energy from specified physical resources that are contractually obligated to flow (or, in the case of DR, curtail) to meet their energy needs on a forward basis; or

(3) Replacing the current RA capacity / CAISO must-offer obligation construct with a fixed price forward energy requirement similar to Option 2, but including a financial hedging component that allows for risk arbitrage and price discovery on the part of generators, which can result in lower forward prices for customers.

A. Fundamental Modifications to the Existing Capacity Construct

Building off the current reliability capacity construct, two sets of modifications could address the concerns associated with reliance on use limited resources to ensure that California has sufficient resources to reliably serve load and to address potential system market power in an RA-only capacity market. These include (1) MCC bucket modifications that would make the buckets binding and (2) changes to the RA must-offer requirements to include either least-cost dispatch or a bid cap.

1. Changes to the MCC Buckets

To ensure that California has sufficient resources to reliably serve load, the MCC buckets require more substantial revisions than the recently revised percentage allocations so that the use of the buckets is reflective of the actual use limitations of the resource. As noted above, resources do not have a binding designation that is attached to the physical capabilities, nor does the Commission have insight into all contractual use-limitations that may exist. Thus, in some cases, parties have, for example, argued that 4-hour storage resources should be included in MCC Bucket 4 (available 24 x 7) because they are "available" and provide a bid for 24 hours a day, 7 days of week. However, it is not likely that California could reliability run its grid using only these resources.

Accordingly, to address issues associated with non-binding MCC buckets, staff offers two potential enhancements. First, the CPUC could require resources to be bucketed based on their physical capabilities. This could be accomplished with resource specific data from CAISO's Masterfile, or based on other use limitation data supplied by resources to the CAISO. Following this categorization process, CAISO and the CPUC could post the proposed MCC bucket designations, similar to the process used for the net qualifying capacity list. This process would allow for a resource owner to change its MCC bucket designation to a more restrictive bucket if there are contractual use limitations that are not reflected in the Masterfile or other use-limited data.

Staff recognizes that there are complex issues associated with this process that need further consideration and development. For example, CAISO's Masterfile "use-limited flag" does not capture all the use limitations of the resource fleet. In its commitment cost enhancement stakeholder process, CAISO changed the definition of use limited resources status to include only those resource that have use limitations that extend beyond the market day. As a result, gas-fired and hydro resources in CAISO's Masterfile include a use-limited flag, but storage and DR resources do not (see the tables below, which also categorize these resources based on whether they are dispatchable or not). As a result of this analysis, it is clear that additional work needs to be done to identify critical use limitations and how to ensure that load serving entities ensure sufficient resources are built and under contract to reliably and cost-effectively operate California's grid.

The table below reflects resource by fuel type with and without a use limited flag in the Master file. The August NQC value is reported. This data reflects the fact that 31% of the resource fleet on the 2020 NQC list has a use limited flag in the Master file. Approximately 50 percent of these resources are gas and 50 percent are hydro resources.

Table 5. Use Limitation Flags in the Masterfile for All Resources

All Resources on NQC List (Aug. MW)					
	Use limited flag identified in Masterfile				
Fuel Type	No	Yes	Not on Masterfile	Total	ULR Percentage of total
Biogas	196			196	
Biomass	357	23		380	0.2%
Distillate	165			165	
Natural Gas	21,683	7,425		29,108	49.7%
Geothermal	1,139			1,139	
Battery	125			125	
Nuclear	2,280			2,280	
Other	1,436			1,436	
Solar	2,997			2,997	
Waste	77			77	
Water	818	7,482		8,300	50.1%
Wind	1,227			1,227	
Demand Response			266	266	
Total	32,501	14,930	266	47,696	
Use Limited Percentage of total	68%	31%	1%	100%	100.0%

We also looked at dispatchability status of the resource to understand if use limited flags were identified for non-dispatchable resources. The table below reports only the August NQC values for resources that are dispatchable. However, the numbers tell us that almost all resources with a use limited flag in the Master file are dispatchable.

Table 6. Use Limitation Flags in the Masterfile for Dispatchable Resources

All dispatchable resources on NQC List (Aug. NQC)					
	Use limited flag identified in MF				
Fuel Type	No	Yes	Not on Masterfile	Total	ULR Percentage of total
Biogas	15			15	
Biomass	70	23		93	0.2%
Distillate	165			165	
Natural Gas	20,713	7,425		28,138	49.8%
Geothermal	1,067			1,067	
Battery	90			90	
Other	1,340			1,340	
Waste	34			34	
Water	544	7,473		8,017	50.1%
Demand Response			195	195	
Total	24,038	14,921	195	39,154	
Use Limited Percentage of total	**61%**	**38%**	**0%**	**100%**	**100%**

Table 7. Dispatchable Flag in the Masterfile for All Resources on the NQC List

All Dispatchable Resources on NQC List (Sept. NQC)				
Fuel Type	No	Yes	Total	% of dispatchable
Biogas	181	16	197	8%
Biomass	288	83	371	22%
Coal	10		10	0%
Distillate		165	165	100%
Natural Gas	902	28,232	29,135	97%
Geothermal	74	1,067	1,141	94%
Heat Recovery	29		29	0%
Battery	31	90	121	74%
Nuclear	2,280		2,280	0%
Other	54	1,333	1,387	96%
Solar	1,554		1,554	0%
Waste	42	34	76	45%
Water	220	7,519	7,739	97%
Wind	877		877	0%
Demand Response	51	196	247	79%
Total	6,594	38,735	45,329	
% of total	**15%**	**85%**	**100%**	

Staff has not yet been able to examine other use limited data that could help in categorizing resources by buckets. However, it is clear that a use limited flag (in the Masterfile) alone will not be sufficient to identify what bucket a resource belongs in. Staff would like to work with CAISO and other stakeholders to identify what specific use limited data should be used to optimally categorize resources by bucket to ensure that a physical capability are taken into consideration when an LSE contracts for a resource to meet its RA needs.

Second, it is likely that RA contract would also need to specify the applicable MCC bucket, to ensure that it binds the LSE to the requirement and a defined product in the market. These two enhancements – bucketing resources by use-limitation and inclusion of these designations in contracts – would allow the CPUC to ensure that the right mix of resources is procured and available to the grid.

Several questions remain and should be resolved prior to evaluating and developing this proposal. First, is CAISO data sufficient to identify and categorize use-limited resources, and if it is sufficient, what specific data should be used (e.g., resource starts, run hours, etc.)? Second, how would CAISO and the CPUC address and classify use limitations that change throughout the year? For example, if a resource runs through its resource use-limitations (startups, water restrictions, etc.) mid-way through the year, should this affect the bucket for the remainder of the year? And if there were such a reclassification mechanism, how would a generator ensure that it meets its MCC bucket categorization contract obligation? Third, how would existing contracts comply with this obligation if their contracts do not specify the resource bucket category? Andfinally, how could future contracts address uncertainties regarding changes to the buckets?

These questions would need further exploration and understanding before the CPUC could categorize resources and develop a binding bucket proposal. Answers to these questions are a pivotal part of identifying whether it is possible to categorize resources by buckets.

2. Applying a Bid Cap to the RA Must Offer Obligation

While the previous modifications address the issue of ensuring that the right resources are brought to the CAISO market to reliability operate the grid, this modification addresses how the CPUC could limit the impacts of system market power in the RA capacity-only market that has developed in California, in part due to load migration.

To address market power, staff proposes that the CPUC could require least-cost dispatch bids or impose a bid cap for RA resources. As noted by CAISO's Market Surveillance Committee, SCE, and other parties, a bid cap could help to ensure that capacity contracted to meet California reliability needs and is indeed available to do so (e.g., could not bid at the $1000 - $2000 cap and thus not provide the capacity/energy when needed by the market). This requirement would prevent California ratepayers from paying for capacity that they do not receive, given that the RA program is intended to address system needs under normal operating conditions, whereas bidding at the current price cap of $1,000 per MWh (which will increase to $2,000 per MWh in the fall of 2021) basically ensures that the capacity will <u>not</u> provide customers with any benefits under normal operating conditions. While a bid cap does not ensure that RA resources will bid into the market at their marginal costs (similar to least cost dispatch requirements currently applicable to the IOUs under CPUC's jurisdiction), it does ensure that RA resources would be subject to a price cap on their bids which would be significantly lower than the current $1000/MWh (rising to $2000/MWh) FERC hourly bid cap.

Issues to be resolved before implementing this second proposed modification include:

- The level of the price cap;
- How existing contracts would be treated;
- How the CPUC could verify these bidding obligations if CAISO does not jointly implement such a proposal;
- How the CPUC would enforce this (RA penalties if bidding does not comply); and
- Whether there are any legal obstacles that would impede the CPUC from implementing such an approach and, if so, design changes that could address any such challenges.

Staff intends to develop additional analysis on this aspect of the Fundamental Modifications to the Existing RA Construct option in the next iteration of this proposal.

B. Enhancing or Replacing the Existing RA Forward Capacity Requirement with a Forward Energy Requirement

At the beginning of the RA program, the CPUC chose to move in the direction of a capacity-based RA program, requiring that load serving entities have sufficient capacity under contract only to meet their monthly peak demands, rather than an energy-based RA program, with load serving entities demonstrating that they have sufficient resources to meet all of their energy needs, not just peak needs. As explained throughout this paper, the capacity-based approach is experiencing challenges as a result of the retirement of California's older gas fleet, which is typically available to provide reliability services during any hour and for as many hours as necessary(aside from maintenance, forced outages, air permit limitations, or contractual limitations), and the replacement of these older resources with use-limited resources such as intermittent renewable generation, four-hour batteries, and demand response (which might also be backed by use-limited storage devices).

Thus, another potential approach for the CPUC to consider would be to replace or enhance the current construct with physical energy requirements, an approach that may also better align with reliability modeling performed in the CPUC's Integrated Resource Planning process. A physical forward energy requirement addresses numerous issues. First, it ensures that each load serving entity brings sufficient energy to meet its electrical requirements and, thus, collectively ensures that there will be sufficient energy in the market to meet the needs of the entire system in all hours of the year. Second, it addresses potential energy market power issues, because if these contracts are at fixed prices, all load serving entities would be highly hedged. If the contracts are not at fixed prices, but set at a CAISO index, for example, it addresses the need to have energy secured to meet an LSE's load, but it does not ensure that hedging occurs. If entities are unhedged, they can be returned to the provider of last resort should market prices increase precipitously – with all the attendant risks discussed previously.

A number of issues would need to be resolved before such an approach could be implemented, including:

- How existing contracts would be treated;
- How would energy availability be calculated and confirmed for resources;
- How the CPUC would monitor and enforce compliance;
- What changes would be need to the load forecast process to set hourly energy requirements;
- How many years forward should requirements be set and what percentages should they be set at; and
- How the current MOO requirements would apply to a physical energy requirement (on a going forward basis or during the transition).

Staff intends to develop additional analysis of the forward physical energy option in the next iteration of this proposal.

C. Standardized Fixed-Price Forward Energy Requirement with Financial Hedging Component

This proposal builds off the forward energy requirement proposal that was first presented by Stanford Economics Professor Frank Wolak at the November 1, 2019, RA workshop held in Sacramento. This proposal is encapsulated in the recent publication of a paper entitled "Market Design in a Zero Marginal Cost Intermittent Renewable Future," available here and included as an attachment to this paper.

The paper describes how the increased penetration of intermittent energy on the system and the potential for sustained periods of low intermittent energy production creates medium and long-term energy supply risks that may warrant a new long-term resource adequacy mechanism. Given this risk, the paper argues that a traditional capacity-based approach is unlikely to be the least cost mechanism for ensuring that future energy demand is met under all possible system conditions and renewable resource output levels. As noted in the paper, these periods of low intermittent production imply the need for greater risk management activities between different generation resources.

The proposal lays out a long-term resource adequacy approach that would mitigate energy supply risk and ensure reasonable cost for consumers, while also allowing the short-term wholesale volatility necessary to finance investments in storage and other load shifting technologies necessary to manage the growing portion of intermittent renewable generation on the grid.

The proposal put forward in the paper can be summarized as follows:

In coordination with the CPUC, the wholesale market operator (CAISO) would run a multi-round annual auction for an hourly standardized fixed-price forward contract (SFPFC), procuring sufficient units of SFPFC to meet forecasted load on a multi-year forward basis.

The SFPFC would be shaped to the hourly system demand within the delivery period of the contract. The percentages of the standard product would start at 100% of realized demand in the current year and gradually decline to 85% in year four, although the future year percentages could be set higher or lower depending on the CPUC concerns about long-term resource adequacy. The cost of the SFPFCs would be allocated to LSEs based on their actual share of system demand during each month. To ensure 100% coverage of realized system demand in SFPFCs, there would need to be true-up auctions after the compliance period, with the purchases from these auctions allocated to LSEs in the same manner. Basing the allocation on a LSEs actual share of system demand during the month, can easily accommodate retail competition, because if one LSE loses load and another LSE gains it during the month, the share of the aggregate hourly cost of SFPFCs allocated to first LSE falls and the share allocated to the second LSE increases.

Generators would be allowed to sell a maximum calculated amount of firm energy (to count towards the SFPFC), using a mechanism similar to what is currently used to compute firm capacity values, which supports reliability by tying the amount of SFPFC to the amount of firm energy generators can produce. The firm energy amount would be calculated by multiplying a unit's MWs of firm capacity by the number of hours in the year. Because the amount of firm energy a generator could use is a function of how much it can produce during stressed system conditions, wind and solar resources would receive a much lower firm energy value than conventional generation (even though the conventional resources do not run as much). This type of structure would allow for cross technology hedging to occur, which could lead to generators providing more attractive (i.e., lower) SFPFC bids. Other approaches to computing firm energy from generation technologies can be considered as long as they are consistent with supporting cross-hedging of energy supply risk between dispatchable thermal resources and intermittent renewable resources.

In addition to the SFPFC auction, the wholesale market operator would also run a clearinghouse to manage counterparty risk associated with these contracts.

This mechanism also would provide an incentive for new generation to be built because of the SFPFC sales by prospective entrants beginning deliveries in four years. The approach moves away from a resource specific RA approach to a fixed price standard contract approach with confirmation at the resource level that the SFPFC product is supported by resources that have confirmed available energy to meet the standard product for the quantity awarded in the auction. Under this approach LSEs (and their customers) are protected from high short-term prices through the financial hedge provided in SFPFC holdings.

Some questions that would need to be answered if the CPUC chose to move in this direction include:

- How the forward energy commitments would feed into CAISOs current market mechanism? For example, how and when would suppliers communicate what physical resources, they will be bidding into the short-term markets to meet their awarded SFPRC obligation?
- How such a mechanism would interact with other policy programs such as IRP and the Renewables Portfolio Standard (RPS)?
    - Would IRP reference system plans feed into the procurement decision made in the SFPRC auction?
    - Would this frameworkalter LSEs' ability to meet RPS procurement mandates?
- What methodologies would be used to calculate the maximum available firm energy of resources?

- What role would LSEs play in serving load?
  - Would LSEs buy energy in the short-term markets to meet their load or would there no longer be a need to do this given the long-term forward energy procurement has already been procured?
  - What additional hedging products would be available to LSEs to compete on price?
- How would demand-side dispatchable resources participate in this framework?
  - Would CAISO buy dispatchable demand products as part of the standard product (via the auction)?
  - Would DR reduce hourly forecasted demand reducing the forward energy requirement (and an LSE's share of that requirement)?
- Would there be a way to modify this proposal to be an LSE based requirement rather than a central buyer requirement? What would be the benefits and drawbacks of this change (i.e. load migration, procurement autonomy)?
- Who would be the central buyer? If CAISO, should they agree, would CAISO being the central buyer raise jurisdictional concerns, and/or could jeopardize clean reliability mandates?
- What step would need to be taken to address local needs and constraints?
  - The CPUC recently adopted a centralized capacity framework for local RA in which SCE and PGE are acting as the CPE for their service territories.
  - Could we bridge this current framework with a forward energy system requirement? And if so, how?

In today's reliability construct we assume that RA-only resources will offer their energy into the market economically and this is based on the assumption that the market is competitive. However, this assumption may be challenged by the fact that a finite number of MWs are actually available during the most critical hours of the day when variable energy resources are no longer producing at their zero marginal costs and conventional generation is not under contract to delivery energy at a fixed energy price.

The SFPFC approach to long-term resource adequacy recognizes that having the ability serve demand does not ensure that the contracted capacity will be available to serve load if suppliers have the ability offer speculative supply resources and/or exercise unilateral market power. This is a key aspect that would change the current value proposition compared with the current RA framework.

Staff intends to develop additional analysis of the SFPFC option in the next iteration of this proposal.

V. Proposed Schedule

The July 7, 2020 Revised Scoping Memo put forward the following schedule for Track 3.B. The ruling additionally sought party comments, to be filed in conjunction with Track 3.B proposals, on what additional process would be helpful in examining the Track 3.B issues (e.g., workshops, written comments, working group).

Table 8. Track 3.B Calendar Schedule from Scoping Memo

Track 3.B Calendar	
Initial Track 3 proposals and comments on process from parties and Energy Division due	August 7, 2020
Potential working groups to aid in the development of proposals	August – September 2020
Workshop(s) on Energy Division and party proposals	Late September / Early October 2020
Final Track 3 proposals due	October 15, 2020
Comments on workshop and all proposals	November 6, 2020
Reply comments on workshop and all proposals	November 20, 2020
Proposed decision on Track 3.B	Q1 2021

Energy Division staff are concerned that the current schedule may be too ambitious, given the scope of potential issues associated with major changes to the RA framework. Accordingly, Energy Division staff propose that the schedule be revised to accommodate a number of iterations of proposals and allow for consideration of additional time early next year. Staff's proposed schedule would include the following:

- September- October 2020 – Comments on Draft Proposals
- November 2020 – Workshops on Draft Proposals
- December 2020 – Revised Proposals
- January 2021 – Comments on Revised Proposals
- February 2021 – Workshops on Revised Proposals
- March 2021 – Second Revised Proposals
- April 2021 – Determination of whether additional time is needed for further consideration of significant changes to the RA construction based on feedback from stakeholders and other parties

VI. Appendix – Frank Wolak Proposal

Market Design in a Zero Marginal Cost Intermittent Renewable Future

by

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1. Introduction

The basic features of an efficient short-term wholesale market design do not need to change to accommodate a significantly larger share of zero marginal cost intermittent renewable energy from wind and solar resources. A large share of controllable zero marginal cost generation does not create any additional market design challenge relative to a market with a large share of controllable positive marginal cost generation. In both instances, generation unit owners must recover their fixed costs from sales of energy, ancillary services, and long-term resource adequacy products.

A larger variance in the hourly amount of energy produced by intermittent resources is the primary market design challenge associated with a zero marginal cost renewable future. The past ten years in California has demonstrated that as the amount of wind and solar generation capacity increases, the variance in hourly megawatt-hours (MWhs) produced by these resources increases. This increase in supply uncertainty increases short-term price volatility, which can support needed investments in storage and other technologies that allow consumers to shift their withdrawals of grid-supplied energyaway from periods when little wind and solar energy is being produced.

An increased risk of large intermittent energy shortfalls and short-term price volatility resources implies a greater need for risk management activities. The short-term intermittent energy supply risk is likely to require accounting for more transmission and generation operating constraints in the day-ahead and real-time energy markets as well as purchasing more operating reserves and creating additional ancillary services products. Because controllable generation units are likely to have to start and stop more frequently to make up for unexpected renewable energy shortfalls, there will be a greater need to develop short-term pricing approaches that recover the associated start-up and minimum load costs.

The potential for sustained periods of low intermittent energy production creates both a medium and long-term energy supply risk that requires a new long-term resource adequacy mechanism. The traditional capacity-based approach is unlikely to be the least cost mechanism for ensuring the future demand for energy is met. Long-term resource adequacy in a zero marginal cost intermittent energy future must ensure that these resources to re-insure their energy supply risk with controllable generation resources. Cross hedging between these technologies accomplishes two goals. First, it can provide the revenue stream necessary for fixed cost recovery by controllable generation units. Second, it ensures that there is sufficient controllable generation capacity to meet demand under all possible future system with a high degree of confidence.

The remainder of the paper first describes the key features of an efficient short-term wholesale market design—a multi-settlement locational marginal pricing (LMP) market with an automatic local market power mitigation mechanism—the standard for all short-term markets in the United States. This section concludes with a discussion of modifications of this basic design likely to be necessary to accommodate a larger share of intermittent renewables.

The second half of the paper first a new long-term resource adequacy mechanism for an electricity supply industry with a large share of zero marginal cost intermittent renewables. I first explain why a wholesale electricity market requires a long-term resource adequacy mechanism. I then describe a mandated standardized long-term contract approach to long-term resource adequacy that provides strong incentives for intermittent renewable resource owners to hedge their energy supply risk with controllable generation resource owners. I argue that this mechanism ensures long-term resource adequacy at a reasonable cost for final consumers while also allowing the short-term wholesale volatility necessary to finance investments in storage and other load-shifting technologies necessary to manage large share of intermittent renewable resources.

2. Short-Term Market Design

More than twenty-five years of international experience with wholesale electricity markets around the world has identified four crucial features of an efficient short-term market design. First is the extent to which the market mechanism used to set dispatch levels and locational prices is consistent with how the grid and generation units actually operate. Second is a financially binding day-ahead market that prices all transmission and generation unit operating constraints expected to be relevant in real-time. Third is an automatic local market power mitigation mechanism (LMPM) that limits the ability of a supplier to influence the price it is paid when it possesses a substantial ability to exercise unilateral market power. Fourth is retail market policies that foster active participation of final demand in the wholesale market.

The early US wholesale market designs in the PJM Interconnection, ISO New England, California, and Texas employed simplified versions of the transmission network configuration and generation unit operating constraints. Similar market designs currently exist throughout Europe and the rest of the world. They set a single market-clearing price for an hour for an entire control area or for large geographic regions, despite the fact that in real-time there are often generation units with offer prices below this market-clearing price not producing electricity and units with offer prices above this market-clearing price producing electricity. This outcome occurs because of the location of demand and available generation units within the region and the configuration of the transmission network prevents some of these low-offer-price units from producing electricity and requires some of the high-offer-price units to supply electricity. The former units are typically called "constrained-off" units and the latter are called "constrained-on" units.

This approach to short-term market design provides incentives for suppliers to take actions to exploit the fact that in "real-time physics wins," rather than offer their resources into the day-ahead market in an manner that minimizes the cost of meeting demand at all locations in the grid in real-time. Instead, suppliers take actions in the simplified day-ahead market that allow them to profit from knowing they will be needed in real-time or not needed in real-time because of transmission and generation unit operating constraints.

2.1. Locational Marginal Pricing

Starting with PJM in 1998 and ending with Texas in late 2010, all US wholesale markets adopted a multi-settlement locational marginal pricing (LMP) market design that co-optimizes the procurement of energy and ancillary services and includes an automatic local market power mitigation mechanism built into the market software. This design has a day-ahead financial market which satisfies the locational demands for energy and each ancillary service simultaneously for all 24 hours of the following day. A real-time market then operates using the same network model as the day-ahead market adjusted to real-time system conditions. Deviations from purchases and sales in the day-ahead market are cleared using these real-time prices. Both of these markets price all relevant transmission network and other relevant operating constraints on the transmission network and generation units. Combined with the appropriate retail market technical and regulatory infrastructure discussed below, this market design fosters active participation of final demand in the wholesale market.

Only generation unit output levels that are physically feasible will be accepted in both the day-ahead and real-time markets. Prices for the same hour vary depending on whether the location is in a generation-deficient or generation-rich region of the transmission network. The locational marginal price or nodal price at each location is the increase in the minimized value of the "as-offered costs" of serving the locational demands for energy and all ancillary services as a result of a one unit increase in the amount of energy withdrawn at that location in the transmission network. The price of each ancillary service is defined at the increase in the optimized value of the objective function as a result of a one unit increase in the demand for that ancillary service.

The recent experience of many European countries with significant wind and solar resources indicates that the cost of making the final schedules that emerge from their zonal markets physically feasible is likely to get even larger as the amount of intermittent renewable generation capacity increases. According to the European Network of Transmission System Operators for Electricity, these costs were over 1 billion Euros Germany, more than 400 million Euros in Great Britain, over 80 million Euros in Spain, and approximately 50 million Euros in Italy in 2017.

2.2. Multi-Settlement LMP Market

A multi-settlement LMP market has at least a day-ahead forward market and a real-time market each of which employs same market-clearing mechanism. The day-ahead market typically allows generation unit owners to submit three-part offers to supply energy--start-up costs, minimum load costs, and energy offer curves to compute hourly generation schedules and ancillary service quantities and LMPs for energy and ancillary services for all 24 hours of the following day. A generation unit will not be accepted to supply energy in the day-ahead market unless the combination of its offered start-up costs, minimum load costs and energy production costs are part of the least as-offered-cost solution to serving hourly locational demands for all 24 hours of the following day.

The energyschedules that arise from the day-ahead market do not require a generation unit to produce the amount sold or a load to consume the amount purchased in the day-ahead market. Any production shortfall relative to a day-ahead generation schedule must be purchased from the real-time market at that location. Any production greater than a day-ahead schedule is sold at the real-time price at that location. For loads any additional consumption beyond the load's day-ahead purchase is paid for at the real-time price at that location and the surplus of a day-ahead purchase relative to actual consumption is sold at the real-time price at that location.

2.3. Mitigating Local Market Power

The configuration of the transmission network, the level and location of demand, as well as the level of output of other generation units can create system conditions when almost any generation unit or group of generation units has a significant ability to exercise unilateral market power. The constrained-on generation problem is an example of this phenomenon. The unit's owner knows that it must be accepted to supply energy regardless of its offer price. Without a local market power mitigation mechanism, there may be no limit to what offer price the unit's owner could submit and have it accepted to supply energy.

This logic is why *ex ante* market structure-based market power mitigation mechanisms typically used in Europe and other industrialized countries and initially employed in the US, which designate in advance the offers of certain generation units for mitigation for an entire year, miss many instances of the exercise of substantial unilateral market power.

An automated LMPM mechanism built into the market software that relies on actual system conditions to determine whether any supplier has a substantial ability and incentive to exercise unilateral market power is likely to be significantly more effective. This regulator-approved administrative procedure determines: (1) when a supplier has an ability to exercise local market power worthy of mitigation, (2) the value of the supplier's mitigated offer price, and (3) the price mitigated supplier is paid. It is increasingly clear to regulators around the world, particularly those that operate markets with a finite amount of transmission capacity and significant intermittent renewable generation capacity, that an automatic LMPM is necessary for any short-term market design.

2.4. Benefits of a Multi-Settlement LMP Market

A multi-settlement LMP market design can facilitate the active participation of final consumers in the wholesale market and reduce both the input fuel and total variable cost of producing the same amount of thermal energy relative to a multi-settlement zonal market design. The presence of an automatic LMPM mechanism and make-whole payments that guarantee start-up, minimum load, and energy cost recovery for the day for all generation units committed to operate in the day-ahead market reduces the incentive of suppliers to exercise unilateral market power.

Because day-ahead purchases are firm financial commitments, a retailer can sell energy purchased in the day-ahead market at the real-time price by consuming less than its day-ahead energy schedule. This eliminates the need for the regulator to set an administrative baseline relative to which a retailer sells demand response reductions. The day-ahead market also allows retailers and large consumers to submit price-sensitive bid curves respectively, into the day-ahead market to reduce the price and the quantity of energy purchased in the day-ahead market.

On April 1, 2009, California market transitioned to a multi-settlement nodal-pricing market design from a multi-settlement zonal-pricing market. The hourly total quantity of input fossil fuel energy used to produce thermal generation electricity fell by 2.5 percent and the total hourly variable cost fell by 2.1 percent after the implementation of nodal pricing. This hourly variable cost reduction implies a roughly $100 million reduction in the total annual variable cost of producing electricity in California associated with the transition to a LMP market design.

The existence on an automatic local market power mitigation mechanism and make-whole payments that compensate generation unit owners for under-recovery on their start-up and minimum load costs on a daily basis implies that a supplier with no ability to exercise unilateral market will submit an offer price equal to its marginal cost of production. The supplier knows that if its units are committed in day-ahead market they are guaranteed recovery of start-up, minimum load and energy production costs, so it expected profit maximizing for this supplier to submit an offer price for energy equal to the unit's marginal cost.

2.5. Modifications for Large Scale Intermittent Renewables Deployment

A multi-settlement LMP market design is capable of managing a generation mix with a significant share of intermittent renewables. However, modifications are likely to be required as the share of intermittent renewable resources increases. Additional operating constraints will need to be incorporated into the day-ahead and real-time market models for reliable system operation with an increased amount of intermittent renewables.

There is also likely to be a need to introduce additional ancillary services to accommodate a larger share of intermittent renewable energy. For example, the California market introduced a fast-ramping ancillary service product that compensates controllable generation units for not supplying energy during certain hours of the day in order to have sufficient unloaded capacity to meet the rapid increase in net demand (the difference between system demand and renewable generation) in the early evening when the state's solar resources stop producing.

Because controllable resources are likely to have to start and stop more frequently as the share of intermittent resources increases, implementations of convex hull pricing and other mechanisms to limit the magnitude of make-whole payments will need to be developed.

One complaint often leveled against LMP markets is that they increase the likelihood of political backlash from consumers because wholesale prices can differ significantly across locations. Most regions with LMP markets have addressed this issue by charging all customers in a state, region, or utility service territory a weighted average of the LMPs at all load withdrawal points in that geographic region. Under this scheme, generation units are paid the price at their location, but all loads pay a geographically aggregated hourly price. In Singapore all generation units are paid the LMP at their location, but all loads are charged the Uniform Singapore Electricity Price (USEP), which is the quantity-weighted average of the prices at all generation nodes in Singapore. This approach to pricing load captures the reliability and operating efficiency benefits of an LMP market while addressing the equity concerns regulators often face with charging customers different locational prices.

3. Resource Adequacy with Significant Intermittent Renewables

Why do wholesale electricity markets require a regulatory mandate to ensure long-term resource adequacy? Electricity is essential to modern life, but so are many other goods and services. Consumers want cars, but there is no regulatory mandate that ensures enough automobile assembly plants to produce these cars. They want point-to-point air travel, but there is no regulatory mandate to ensure enough airplanes to accomplish this. Consumers want bread, but there is no regulatory mandate to ensure sufficient bakeries to meet this demand. All of these goods are produced using high fixed cost, relatively low marginal cost technologies, similar to electricity supply. Nevertheless, all of these firms recover their cost of production including a return on the capital invested by selling the good at a market-determined price.

So what is different about electricity that requires a long-term resource adequacy mechanism? The regulatory history of the electricity supply industry and the legacy technology for metering electricity consumption results in what I call a *reliability externality.*

3.1. The Reliability Externality

Different from the case of wholesale electricity, in the market for automobiles, air travel, and even bread, there is no regulatory prohibition on the short-term price rising to the level necessary to clear the market. Airlines adjust the prices for seats on a flight over time in an attempt to ensure that the number of customers traveling on that flight equals the number of seats flying. This ability to use price to allocate the available seats is also what allows the airline to recover its total production costs.

Using the short-term price to manage the real-time supply and demand balance in a wholesale electricity market is limited by a finite upper bound on a supplier's offer price and/or a price cap that limits the maximum market-clearing price. Although offer caps and price caps can limit the ability of suppliers to exercise unilateral market power in the short-term energy market, they also reduce the revenues suppliers can receive during scarcity conditions. This is often referred to as the *missing money* problem for generation unit owners. However, this missing money problem is only a symptom of the existence of the "reliability externality."

This externality exists because offer caps limit the cost to electricity retailers of failing to hedge the cost purchases of electricity from the short-term market. Specifically, if the retailer or large consumer knows the price cap on the short-term market is $250/MWh, then it is unlikely to be willing to pay more than that for electricity in any earlier forward market. This creates the possibility that real-time system conditions can occur where the amount of electricity demanded at or below the offer cap is less than the amount suppliers are willing to offer at or below the offer cap. This outcome implies that the system operator must be forced to either abandon the market mechanism or curtail load until the available supply offered at or below the offer cap equals the reduced level of demand, as occurred a number of times between January 2001 and April 2001 in California.

Because random curtailments of supply---also known as rolling blackouts---are used to make demand equal to the available supply at or below the bid cap under these system conditions, this mechanism creates a "reliability externality" because no retailer bears the full cost of failing to procure adequate amounts of energy in advance of delivery. A retailer that has purchased sufficient supply in the forward market to meet its actual demand is equally likely to be randomly curtailed as the same size retailer that has not procured adequate energy in the forward market. For this reason, all retailers have an incentive to under-procure their expected energy needs in the forward market.

The lower the offer cap, the greater is the likelihood that the retailer will delay their electricity purchases to the short-term market. Delaying more purchases to the short-term market increases the likelihood of insufficient supply in the short-term market at or below the offer cap. Because retailers do not bear the full cost of failing to procure sufficient energy in the forward market to meet their future demand, there is a missing market for long-term contracts for long enough delivery horizons into the future to allow new generation units to be financed and constructed to serve demand under all possible future conditions in the short-term market. Therefore, a regulator-mandated long-term resource adequacy mechanism necessary to replace this missing market.

Specifically, unless the regulator is willing to eliminate or substantially increase the offer cap so that the short-term price can be used to equate available supply to demand under all possible future system conditions, some form of regulatory intervention is necessary to internalize the resulting reliability externality. If customers do not have interval meters that can record their consumption on an hourly basis, they have a very limited ability to benefit from shifting their consumption away from high-priced hours, so raising or having no offer cap on the short-term market would not be advisable. Even in regions with interval meters there would substantial political backlash from charging hourly wholesale prices that cause real-time demand to equal available supply under all possible future system conditions.

Currently, the most popular approach to addressing this reliability externality is a capacity payment mechanism that assigns a firm capacity value to each generation unit based on the amount of energy it can provide under stressed system conditions. Sufficient firm capacity procurement obligations are then assigned to retailers to ensure that annual system demand peaks can met.

Capacity-based approaches to long-term resource adequacy rely on credibility of the firm capacity measures assigned to generation units. This is a relatively straightforward process for thermal units. The nameplate capacity of the generation unit times its annual availability factor is a reasonable estimate of the amount energy the unit can provide under stressed system conditions. For the case of hydroelectric facilities, this process is less straightforward. The typical approach uses percentiles of the distribution of past hydrological conditions for that generation unit to determine its firm capacity value.

Assigning a firm capacity value to a wind or solar generation unit is extremely challenging for several reasons. First, these units only produce when the underlying resource is available. If stressed system conditions occur when the sun is not shining or the wind is not blowing, these units should be assigned little, if any, firm capacity value. Second, because there is a high degree of contemporaneous correlation between the energy produced by solar and wind facilities within the same region, the usual approach to determining the firm capacity of a wind or solar unit assigns a smaller value to that unit as the total MWs of wind or solar capacity in the region increases. These facts imply that a capacity-based long-term resource adequacy mechanism is poorly suited to zero marginal cost intermittent renewable feature.

3.2. Supplier Incentives with Fixed-Price Forward Contract Obligations for Energy

The standardized fixed-price forward contract (SFPRC) approach to long-term resource adequacy recognizes that having the ability serve demand at a reasonable price, does not imply that it will occur if suppliers have the ability exercise unilateral market power. Because a supplier with a significant ability to exercise unilateral market power with a fixed-price forward contract obligation finds it expected profit maximizing to minimize the cost of supplying that quantity of energy, this long-term resource adequacy mechanism requires retailers to hold hourly fixed-price forward contract obligations for energy that sum to the hourly value of system demand. This implies that all suppliers find it expected profit maximizing to minimize the cost of meeting fixed-price forward contract obligations that sum to hourly system demandfor all hours of the year.

To understand the incentives created by this mechanism, let PC equal the fixed price at which the supplier sold energy in the standardized forward contract and QC_h equal to quantity of energy sold in hour h. The values of PC and QC_h are predetermined from the perspective of the supplier's behavior in a short-term wholesale market because this contract has been sold advance of the date that the contract clears. In terms of this notation, the supplier's variable profits from selling energy in the short-termmarket and clearing its forward contract obligations for hour h is:

$$\pi(PS_h) = (PC - C)QC_h + (QS_h - QC_h)(PS_h - C), \quad (1)$$

where QS_h is the quantity of energy sold in the short-term market by the generation unit owner in hour h, PS_h is the price of energy sold in the short-term market in hour h and C is the supplier's marginal cost of producing electricity, which for simplicity is assumed to be a constant.

The first term in (1) is the variable profit from SFPRC sales and the second term is the additional profit or loss from selling more or less energy in the short-term market than the supplier's SFRPC quantity. Because the SFRPC price and quantity are known in advance of the delivery date, the first term, $(PC - C)QC_h$, is a fixed profit stream to the supplier submits offers to supply energy into the day-ahead market. Because the second term depends on PS_h, the value of QC_h significantly limits the incentive the supplier has to raise short-term market prices.

If the supplier attempts to raise PS_h by submitting a high offer price, it could end up selling less in the short-term market than its SFRPC quantity ($QC_h > QS_h$), and if the resulting market-clearing price is greater than the firm's marginal cost ($PS_h > C$), the second term in (1) will be negative. Consequently, only if the supplier is confident that its offer price will result in short-term market sales greater than QC_h does it have an incentive to submit an offer price above its marginal cost.

The quantity of forward contract obligations held by a firm's competitors also limits ability a supplier has to exercise unilateral market power in the short-term market. If a supplier knows that all of its competitors have substantial fixed-price forward contract obligations, then this supplier knows that each competitor will find it unilaterally profit-maximizing submit offer prices into the short-term market equal their marginal cost for quantities of energy up to QC_h. Therefore, attempts by this supplier to raise prices in the short-term market by withholding output are likely to be unsuccessful because of the aggressiveness of the offers into the short-term market by its competitors with SFPFC obligations limits the price increase a supplier can expect to achieve from these actions.

3.3. SFPFC Approach to Resource Adequacy

This long-term resource adequacy mechanism requires all electricity retailers to hold SFPFCs for energy for fractions of realized system demand at various horizons to delivery. For example, retailers in total must hold SFPFCs that cover 100 percent of realized system demand, 95 percent of system demand one year in advance of delivery, 90 percent two-years in advance of delivery, 87 percent three years in advance of delivery, and 85 percent four years in advance of delivery. The fractions of system demand and number of years in advance that the SFPFCs must be purchased are parameters set by the regulator to ensure long-term resource adequacy. In the case of a multi-settlement LMP market, the SFPFCs would clear against the quantity-weighted average of the hourly locational prices at all load withdrawal nodes.

SFPFCs are shaped to the hourly system demand within the delivery period of the contract. If QD_h is equal to the system demand in hour h of the delivery period and QT_j is the total MWhs of the standardized contract sold by supplier j during the delivery period for j=1,2,..J, thenthe forward contract obligation of supplier j during hour h is $QC_{jh} = (\frac{QD_h}{\sum_{h=1}^{H} QD_h})QT_j$, the system demand shaped hourly profile during the delivery period of QT_j, the total MWhs of SFPFCs sold by supplier j for the delivery horizon. Because the mechanism requires retailers to hold total MWhs of SFPFCs equal to their total demand during the delivery period, the total amount SFPFC obligations sold by suppliers for the delivery horizon is equal to total system during that delivery horizon. To the extent that the total amount of QT purchased in the forward market is more or less than realized system demand during the delivery horizon, a true-up auction run after annual demand has been realized would buy or sell the amount of QT needed to make $\sum_{j=1}^{J} QT_j = \sum_{h=1}^{H} QD_h$. By allocating each supplier's total SFPRC obligations according to the actual hourly load shape during the delivery horizon, total hourly SFPFCs obligations across all suppliers is equal system demand for all hours of the delivery horizon.

These standardized fixed-price forward contracts are allocated to retailers based on their share of system demand during the month. Let QR_{kh} equal the realized demand of retailer k during hour h for h=1 to M, where M is the number of hours in the month and k=1 to K, where K is the number of retailers. Because all retailers are assigned standardized fixed-price forward contract obligations, $QD_h = \sum_{k=1}^{K} QR_{kh}$, hourly system demand is equal to the hourly demand of all retailers for each hour of the month. Shares of the aggregate quantity of SFPFCs obligations for each hour of the month, QTC_h, are assigned to each retailer each hour of the month according to the following rule: $QRC_{kh} = (\frac{\sum_{h=1}^{M} QR_{kh}}{\sum_{h=1}^{M} QD_h})QTC_h$. Under this scheme, retailer k's variable profits in hour h from selling energy to final consumers at PR is:

$$\Pi_R(PS_h) = (PR - PS_h)QR_{kh} + (PS_h - PC)QRC_{kh.} \qquad (2)$$

The hourly variable profits of generator j in hour h in equation (1) can be re-written as:

$$\Pi_G(PS_h) = (PS_h - C)QS_{jh} - (PS_h - PC)QC_{jh,} \qquad (3)$$

Because the sum of hourly SFPFCs allocated to retailers is equal to the sum of the hourly SFPFC obligations of suppliers, the sum of the second term in (3) over all suppliers equals the sum of the second term in (2) over all retailers on an hourly basis.

The SFPRCs only influence the magnitude of payments between suppliers and retailers each hour. Because the sign and magnitude of these payments depends on both the short-term market price and quantity sold, they affect the supplier's incentive to offer that quantity of energy into the short-term market. A generation owner with a SFPRC obligation of QC maximizes expected profits by submitting an offer price equal to marginal cost for this quantity of energy.

This offer price ensures that supplier j makes the economically efficient "make versus buy" decision to supply QC_{jh} units of output. If the PS_h is above C, then it is cheaper to produce QC_{jh} from its generationunits, but if PS_h is below C then it is cheaper to QC_{jh} from the short-term market. Submitting an offer price equal to the supplier j's marginal cost for all output levels up to QC_{jh} ensures that the market-clearing mechanism yields the efficient outcome. If all suppliers submit offer prices that yield the efficient "make versus buy decision" for their QC_{jh}, then all generation unit owners will find it unilaterally profit maximizing to produce system demand in a cost-effective manner possible because the sum of the QC_{jh} over the J suppliers is equal to system demand for the hour. Because this equality holds for all hours of the year, this incentive to produce system demand in a cost-effective manner also applies on a yearly basis.

3.4. Mechanics of Standardized Forward ContractProcurement Process

The SFPFCs are purchased through auctions several years in advance of delivery in order to allow new entrants to compete to supply this energy. Because the aggregate hourly values of these contract obligations are allocated to retailers based on their actual share of system demand during the month, this mechanism can easily accommodate retail competition. If one retailer loses load and another gains it during the month, the share of the aggregate hourly value of SFPFCs allocated to first retailer falls and the share allocated to the second retailer rises.

The wholesale market operator would run the auctions with oversight by the regulator. One advantage of the design of the SFPFC products is that a simple auction mechanism can be used to purchase each annual product. A multi-round auction could be run where suppliers submit the amount of QT they would like to sell for a given delivery period at the price for the current round. Each round the price would decrease until the amount suppliers are willing to sell at that price is less than or equal to aggregate amount ofQT demanded.

The wholesale market operator would also run a clearinghouse to manage the counterparty risk associated with these contracts. All wholesale market operators currently do this for all participants in their short-term markets. Ina number of US markets, the market operator also provides counterparty risk management services for long-term financial transmission rights, which is significantly different from performing this function for SFPFCs.

SFPFCs auctions would be run on an annual basis for annual producing making deliveries starting two, three and four years in the future. In steady state, auctions for incremental amounts of each annual contract would also be needed so that the aggregate share of demand covered by each annual SFPFC could increase over time. The eventual 100 percent coverage of demand occurs through a final true-up auction that takes place after the realized values for hourly demand for the delivery period are known.

Each purchase of the same annual SFPFC product is allocated to retailers according to their load shares during the delivery month. If three different size purchases are made for a given annual product at different prices then each retailer is allocated their load share for the month of these three purchases. This ensures a level playing field for retailers with respect to their long-term resource adequacy obligation. All retailers face the same average price for the long-term resource adequacy obligation associated with their realized demand for the month.

The advance purchase fractions of the final demand are the regulator's security blanket to ensure that system demands can met for all hours of the year for all possible future system conditions. If the regulator is worried that not enough resources will be available in time to satisfy this requirement, it can increase the share of final demand that it purchases in each annual SFPFC auctions. If too much QT is purchased in an annual auction, it can be sold back to generation unit owners in a later auction or the final true-up auction. The costs to these decisions will then be allocated to all retailers as part of their long-term resource adequacy obligation.

Cross hedging between controllable generation units and intermittent renewable resources under this mechanism is enforced by tying the amount of QT a generation unit owner can sell on an annual basis to the value of their firm energy. The system operator would assign firm energyvalues for each generation unit using a mechanism similar what is currently used to compute firm capacity values. Multiplying a unit's MWs of firm capacity by the number of hours in the year would be the unit's firm energy value, which is the upper bound on the amount of QT the unit owner could sell in all auctions for an annual compliance period. Because the firm capacity of a generation unit is defined as the amount of energy it can produce under stressed system conditions, this limitation on annual sales of QT, implies that intermittent wind and solar resources would sell much less QT than the total MWhs they expect to produce in an average year and controllable generation unit owners would sell significantly more QT than the total MWhs they expect to produce in an average year.

In most years, controllable resource owner j would be producing energy in a small number of hours of the year, but earning $(PC - PS_h)QC_{jh}$ in all the hours that it produces no output. Intermittent renewables owners would typically produce more than their SFPFC obligation in energy and sell the additional energy at the short-term price. In years with low renewable output near their SFPRC obligations, controllable resource owners would produce close to their QC_{jh} values and average short-term prices would be significantly higher because of that. Because of their SFPFC holdings, aggregate retail demand would be shielded from these high short-term prices.

3.4. Advantages of SFPRC Approach to Long-Term Resource Adequacy

This mechanism has a number of advantages relative to a capacity-based approach. There is no regulator-mandated aggregate capacity requirement. Generation unit owners are allowed to decide both the total MWs and of mix of technologies to meet their SFPFC energy obligations. There is also no prohibition on generation unit owners or retailers engaging in other hedging arrangements outside of this mechanism. Specifically, retailers could enter into a bilateral contract for energy with a generation unit owner or other retailer to manage the short-term price and quantity risk associated with the difference between their actual hourly load shape and their hourly values of QR_{kh}. This mechanism provides a nudge to market participants to develop a liquid market for these bilateral contract arrangements at horizons to delivery similar to the SFPRC products. Instead of starting from the baseline of no fixed-price forward contract coverage of system demand by retailers, this mechanism starts with 100 percent coverage of system demand, which retailers can unwind at their own risk.

For the regulated retail customers, the purchase prices of SFPRCs can be used to set the wholesale price implicit in the regulated retail price over the time horizon that the forward contract clears. This would provide retailers with a strong incentive to reduce their average wholesale energy procurement costs below this price through bilateral hedging arrangements, storage investments or demand response efforts.

There are a number of reasons why this mechanism should be a more cost-effective approach to long-term resource adequacy in a zero marginal cost intermittent future than a capacity-based mechanism. First, the sale of SFPFC energy starting delivery two or more years in the future provides a revenue stream that will significantly increase investor confidence in recovering the cost of any investment in new generation capacity.

Because retailers are protected from high short-term prices by total hourly SFPFC holdings equal to system demand, the offer cap on the short-term market can be raised in order to increase the incentive for all suppliers to produce as much energy as possible during stressed system conditions. The possibility of higher short-term price spikes will support investments in storage and load-shifting technologies and encourage active participation of final demand in the wholesale market, further enhancing system reliability in a market with significant intermittent renewable resources.

If SFPFC energy is sold for delivery in four years based on a proposed generation unit, the regulator should require that construction of the new unit to begin within a pre-specified number of months after the signing date of the contract or require posting of a substantially larger amount of money in the clearinghouse with market operator. Otherwise, the amount of SFPFC energy that this proposed unit sold would be automatically liquidated in a subsequent SFPFC auction and a financial penalty would be imposed on the developer. Other completion milestones would have to be met at future dates to ensure the unit is able to provide amount firm energy that it committed to provide in the SFPRC contract sold. If any of these milestones were not met, the contract would be liquidated.

4. Final Comments

There is no perfect wholesale market design. There are only better wholesale market designs and what constitutes a better design depends many factors specific to the region. Although there is general agreement on the key features of a best-practice short-term market design, many details must be adjusted to reflect local conditions. For this reason, wholesale market design is a process of continuous learning, adaption, and hopefully, improvement. The standardized energy contracting approach to long-term resource adequacy described in this paper is an example of this process. It has a number of features that are likely make it significantly better suited to a zero marginal cost intermittent renewables electricity supply industry, there are many details of this basic mechanism that should be adaptedto reflect local conditions.

5. Further Reading

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6. Figures

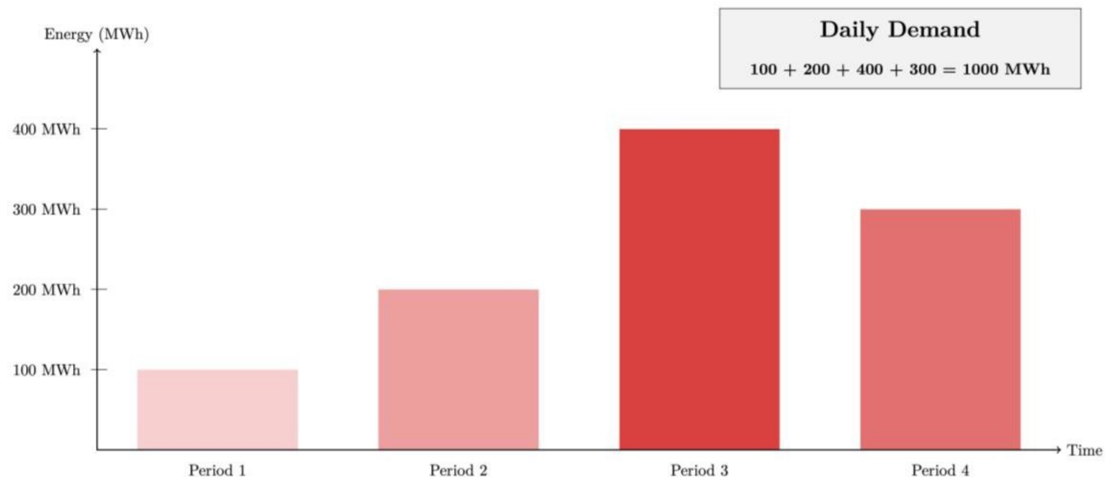

Figure 13: Hourly System Demands for Single Day

There are Three Firms:

Firm 1 sells 300 MWh

Firm 2 sells 200 MWh

Firm 3 sells 500 MWh

Total Amount Sold by Three Firms = 1000 MWh

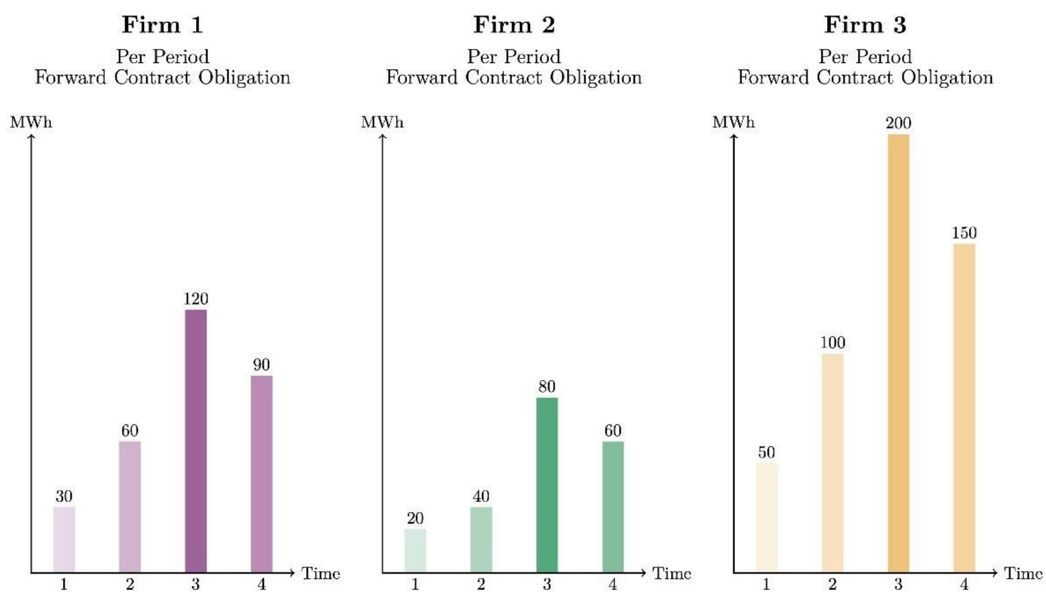

Figure 14: Hourly Forward Contract Quantities for Three Suppliers

There are Four Retailers:

Retailer 1 sells 100 MWh

Retailer 2 sells 200 MWh

Retailer 3 sells 300 MWh

Retailer 4 sells 400 MWh

Total Amount Sold by Four Retailers = 1000 MWh

Figure 15: Hourly Forward Contract Quantities for Four Retailers

(END OF APPENDIX A)