

The Brattle Group

Resource Adequacy in California Options for Improving Efficiency and Effectiveness

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EXECUTIVE SUMMARY

We have been asked by Calpine, a generation owner and developer in California and nationally, to evaluate the efficiency and effectiveness of California's approach to attracting and sustaining investments for electric resource adequacy. Our analysis focuses on: (1) the Local and System Resource Adequacy Requirement (RAR) that the California Public Utilities Commission (CPUC) imposes on retail suppliers; and (2) the Long Term Procurement Plan (LTPP) process through which the CPUC oversees the procurement of new conventional generation by investor owned utilities (IOUs) on behalf of all CPUC-jurisdictional load serving entities (LSEs) as well as the IOUs' procurement of new and existing resources on behalf of bundled customers. These interrelated but uncoordinated mechanisms were initially introduced in response to the Western power crisis and have evolved over the past decade with changing circumstances and policy goals.

Looking out over the coming decade, California faces two pressing challenges to meeting the State's environmental and reliability objectives that were not anticipated at the time the current framework was developed. The first challenge is the once-through cooling mandate that will require approximately 16,000 MW of existing generators, representing one-third of California's fleet, to either retire or invest in costly environmental upgrades over the next decade. The second challenge is California's renewable portfolio standard (RPS) to procure 33% of customers' energy from renewable resources by 2020. Bringing these large quantities of intermittent wind and solar generation into the system will suppress energy market prices and require additional resources that can operate flexibly enough to balance the variable renewable generation output.

These new challenges highlight the need to take a fresh look at California's resource adequacy framework so that it is better aligned with policy objectives and better able to meet these objectives at lowest cost. In reviewing the current mechanisms that were independently developed for separate purposes, we identified a number of inefficiencies as explained in Section II of this report. Many of these inefficiencies stem from the fact that these mechanisms do not constitute an integrated approach that fosters competition among different types of capacity resources. These inefficiencies include:

Price discrepancies among different types of capacity resources – Currently, different types of capacity resources are paid very different prices for providing the same product, with existing resources earning only approximately \$18-38/kW-year (or less) under the RAR program while IOUs are paying the equivalent of \$150-300/kW-year in capacity payments for contracts with new resources under LTPP. This large price discrepancy indicates that California is likely substantially overpaying for new generation and forgoing lower-cost opportunities to retain existing resources. Many existing resources may retire prematurely if they are compensated at these levels, even though they could be retained for less than the cost of building new generation.

Lack of competition between new and existing resources – California does not currently have a bilateral or auction-based market mechanism for fostering efficient, direct competition between new and existing generation resources. Greater competition between new and existing resources would create opportunities to identify relatively low-cost upgrade, retrofit, and repowering opportunities for existing generators, enable the

efficient retirement of units that are no longer economic, and postpone the need to invest in costlier new generation resources.

Uneconomic new generation investments driven by planning uncertainties – There are large uncertainties in the outlook for load growth, retirements, imports, and demand resources. This means that IOU and CPUC projections under LTPP of whether and when new generation will be needed will necessarily prove to be imperfect. In some cases, these uncertainties led to over-estimating the quantity of new resources needed for resource adequacy, and therefore to prematurely building new generation resources at contract prices that far exceed the current cost of alternative supplies.

Potential for inefficient once-through-cooling retirements and retrofits – It is not clear what portion of the 16,000 MW of resources subject to the once-through-cooling mandate over the coming decade will retire and how much (if any) may be retrofitted cost effectively. California does not have a market-based competitive mechanism for evaluating which of these resources could be upgraded cost-effectively and which should retire because lower-cost alternatives exist.

Forward backstop mechanisms that could preempt market alternatives – While the CAISO’s two-year, forward-looking backstop procurement authority has not yet been used, this mechanism has the potential to distort prices in the energy markets and RAR program. Forward out-of-market contracting may pre-empt the market from identifying lower-cost alternatives for meeting the RAR objectives. The new proposal to extend forward backstop procurement authority to five years for flexible resources would also be implemented without any market-based mechanism for assuring that the selected resource is the lowest-cost option for meeting the system’s future flexibility needs.

Inefficient cost-effectiveness tests for demand response – The CPUC cost-effectiveness tests for demand response (DR) resources assume that peak load reductions provide customers \$136/kW-year of savings in capacity costs. This administratively-determined parameter values capacity as if California were in a long-run equilibrium in which the marginal cost of capacity is equal to the net cost of new entry (CONE) for procuring new generation. In reality, California currently has substantial excess capacity and the cost of alternative capacity supplies is only \$18-38/kW-year (or less), meaning that customers may be paying for DR programs whose costs currently exceed their benefits.

Difficulty in attracting third-party demand response – Despite a high DR cost-effectiveness threshold, California may actually be under-procuring low-cost DR by effectively precluding third-party DR suppliers from accessing capacity payments. By allowing third-party curtailment service providers (CSPs) to monetize the value of peak load reductions without going through LSEs, eastern U.S. power markets such as PJM observed rapid growth in low-cost DR, sufficient to cover 10% of the system’s peak load for 2015-16. These third-party DR resources have taken on resource adequacy commitments at capacity prices far below the cost of new generation and the “capacity value” assumed in California’s DR cost-effectiveness tests.

Lack of liquidity and transparency in short-term bilateral transactions – The current RAR program relies solely on bilateral transactions, which are inherently less efficient and transparent than centralized auctions or over-the-counter trading platforms. The bilateral approach also increases transactions costs and makes it more difficult to estimate the value of incremental investments in short-term capacity resources such as DR, generation

uprates, and imports. Creating more transparency through a centralized auction or an over-the-counter capacity exchange would reduce these inefficiencies and better inform appropriate bilateral contract prices.

Overall, these inefficiencies in California's resource adequacy construct will lead to uneconomic investments in new capacity resources when lower-cost alternatives exist, ultimately increasing system and customer costs.

California could gain substantial efficiency benefits by reforming the current LTPP and RAR programs in two important ways. First, the programs could be refined to incorporate *non-discriminatory* procurement practices that invite competition among all types of capacity resources including: (a) new generation; (b) existing generation, including resources with low going-forward costs, as well as those that need major reinvestments or retrofits to continue operating; (c) investments to uprate existing generation facilities; (d) imports; and (e) demand-side resources including DR and energy efficiency. Unless each of these types of resources has the opportunity to compete to supply capacity at the same price and under the same terms, it will not be possible to meet resource adequacy objectives using the lowest-cost mix of supply resources, as we explain in Section III.A. Second, California may gain additional efficiency benefits by procuring all of its needed capacity commitments on a 3-4 year *forward basis*, as explained in Section III.B. Meeting the local and system RAR objectives on a forward basis will increase the scope of competition by awarding capacity commitments at approximately the same time that suppliers need to make major irreversible investment decisions for retrofits and new construction.

To improve procurement efficiency and achieve these benefits, we recommend either: (1) reforming RAR and LTPP to incorporate non-discriminatory procurement practices; or (2) replacing both mechanisms with a forward capacity market. Further, the CPUC and CAISO appear to require assurance of resource adequacy on a forward-looking basis, particularly in light of upcoming once-through-cooling and flexibility challenges. Considering these concerns, the efficiency of either approach could be improved by including 3-4 year forward obligations covering all or most system and local capacity requirements, including requirements for operationally flexible capacity. Ideally, these forward obligations would be met through non-discriminatory, transparent, single-price auctions conducted by CAISO, a state agency, or the IOUs. If administered by a state agency or IOUs, CAISO would need to develop supplemental mechanisms to also cover the resource adequacy requirements of non-CPUC-jurisdictional entities.

Option 1: RAR Capacity Auctions with Non-Discriminatory LTPP Procurement – The current resource adequacy construct would be more efficient and better integrated if all long, intermediate, and short-term procurements under LTPP were conducted on a non-discriminatory basis, with all remaining capacity needs procured at the RAR compliance deadline through a non-discriminatory residual capacity auction with transparent clearing prices. The auction could be administered by a state agency, the IOUs, or the California Independent System Operator (CAISO). Both LTPP and RAR procurements would invite offers from all types of capacity suppliers, including new generation, existing generation, uprates, imports, and demand resource, thereby rationalizing prices and enabling cost-effective tradeoffs among these types of resources. Capacity procurements under LTPP would also be separated from energy procurements, to reduce the potential

for administrative error in evaluating tradeoffs among very different types of resources such as combined cycle (CC) plants and DR that may have the same resource adequacy value but very different energy value.

Implementing non-discriminatory procurement under LTPP would remove the restriction that long-term system procurements are only open to new generation, and would likely require re-framing the “needs determination” assessment to determine what portion of total capacity obligations should be procured at each forward period (*e.g.*, 30% seven years forward, 50% five years forward, and 100% three years forward at the time of the RAR capacity auction). LTPP capacity procurements would also invite offers of any term from one year to many years, creating an opportunity to identify low-cost, short-term resources that may postpone the need to contract for long-term contracts with new resources. Only a portion of system capacity needs would be procured through the RAR auction, because most capacity commitments would continue to be procured on a forward basis prior to the auction. The increased transparency of an RAR auction would also enable more efficient bilateral contracting and LTPP procurements by more clearly identifying system needs and signaling the price at which alternative supplies are available.

Option 2: Replacing LTPP and RAR with a Forward Capacity Market – An alternative option is to completely replace LTPP and RAR with a forward capacity market similar to those in New England and PJM, to be administered by a state agency, the IOUs, or CAISO. Similar to the first option, this approach would include a centralized capacity auction, but because capacity procurements under LTPP would be substantially reduced or eliminated, the auction would produce greater residual clearing volumes and become a more important part of California’s resource adequacy framework. This option would provide the highest level of efficiency by fully leveling the playing field among all resource types. Because this capacity auction would be the primary mechanism for assuring resource adequacy and attracting incremental investments in new and existing generation, it would be important to conduct the auctions on a 3-4 year forward basis, *i.e.*, far enough forward that many suppliers still have the flexibility to make or reverse major investment decisions. A forward capacity market would also provide an efficient platform for co-optimizing procurement for both flexibility requirements and resource adequacy needs.

We provide a more detailed explanation of these options for improving the California resource adequacy construct in Section IV.

I. MOTIVATION

We have been asked by Calpine, a generation owner and developer in California and nationally, to evaluate the efficiency and effectiveness of California's approach to attracting and sustaining investments for electric resource adequacy.¹ Our analysis focuses on: (1) the Local and System Resource Adequacy Requirement (RAR) that the California Public Utilities Commission (CPUC) imposes on retail suppliers; and (2) the Long Term Procurement Plan (LTPP) process through which the CPUC oversees the procurement of new conventional generation by investor owned utilities (IOUs) on behalf of all CPUC-jurisdictional load serving entities (LSEs) as well as the IOUs' procurement of new and existing resources on behalf of bundled customers.

Resource adequacy has been a focus of California energy policy since the state experienced severe high prices and supply shortages during the Western power crisis of 2000-01.² Over the past decade, the CPUC has developed a resource adequacy framework that relies partly on market-based incentives, partly on regulated planning and long-term contracting, and partly on backstop reliability interventions. However, these mechanisms have yet to be harmonized into an integrated approach to meeting system and local resource adequacy needs at lowest cost. In particular, the current approach does not foster direct competition among all types of capacity resources, including: (1) new generating plants; (2) existing generating plants, including cost-effective reinvestments to uprate, life-extend, or retrofit power plants that might otherwise retire; and (3) utility-sponsored and independently-developed demand response (DR) resources. Rather, California's various mechanisms use different criteria to evaluate each type of supply, making them unlikely to achieve the most cost-effective result overall.

Looking out over the coming decade, California faces two pressing challenges to meeting the State's environmental and reliability objectives that were not anticipated at the time the current framework was developed. One challenge is the State Water Resources Control Board's once-through cooling mandate.³ This mandate applies to 19 California power plants using once-through cooling with water drawn from coastal or estuarine sources, and requires them to upgrade to closed-loop cooling systems or implement other measures for comparably reducing impacts on aquatic life. The mandate will affect approximately 16,000 MW of resources, or approximately one-third of California's generating capacity, over the next decade.⁴ In some many cases, the lowest-cost retrofit option may be clearly uneconomic (*e.g.*, a costly new cooling tower investment on an aging plant), but the economics may not be as clear-cut in other cases

¹ As a generation owner and developer in California, Calpine has an interest in the state's mechanisms to ensure resource adequacy. While Calpine has commissioned this whitepaper, its contents represent our independent view and assessment of California's resource adequacy framework. The conclusions that we draw in this whitepaper are solely based on our review and analysis of the California market design for resource adequacy and similar analyses we have undertaken in other markets. For example, see Newell, *et al.* (2009, 2010, 2012); Pfeifenberger, *et al.* (2008, 2009, 2011a-b); LaPlante, *et al.* (2009).

² See Wolak (2003), pp. 17-18.

³ See SWRCB (2012).

⁴ Based on an analysis of individual units' compliance dates and summer capacity, excluding resources with compliance dates prior to 2012 (which have already retired or complied) and excluding resources with compliance dates after 2022. Data from SNL Energy (2012); SWRCB (2012); CAISO (2010). As of August 2010, the 57,345 MW of resources were committed to CAISO for resource adequacy purposes, see CPUC (2011a), p. 13.

(e.g., alternative upgrades that are somewhat lower-cost, or a cooling tower on a plant that may operate for many more years). Ideally, California's resource adequacy framework would use bilateral or auction-based market mechanisms to weigh the costs of reinvesting in these facilities against the costs of alternative sources of replacement supply. Unfortunately, current resource adequacy processes do not facilitate tradeoffs of this sort.

A second emerging resource adequacy challenge arises from California's renewable portfolio standard (RPS) to procure 33% of customers' energy from renewable resources by 2020.⁵ Most of the new supply will be from intermittent wind and solar generation. Such a large amount of intermittent generation will create a need for additional resources that can operate flexibly enough to balance the variable renewable generation output. The California Independent System Operator (CAISO) and CPUC have both initiated efforts to address these intermittent resource integration challenges. However, these efforts have not yet developed into a market-based approach to assuring sufficient flexible resource capability in a manner that is consistent with the resource adequacy framework and the CAISO-administered ancillary service (A/S) markets.

This whitepaper discusses the inefficiencies in the interplay among California's current resource adequacy mechanisms, summarizes relevant experience from other power markets, and presents options that could be pursued to resolve these concerns. The options we describe rely on market mechanisms that foster competition among all types of capacity resources, while maintaining consistency with what we believe are the CPUC's policy goals, including: (1) meeting system and local reliability needs at lowest cost; (2) meeting environmental objectives cost-effectively; and (3) maintaining state regulators' ability to pursue environmental and other state policy objectives.

II. CALIFORNIA'S RESOURCE ADEQUACY FRAMEWORK

California's resource adequacy framework relies on a number of interrelated but uncoordinated mechanisms. In this Section, we describe these mechanisms and describe their various inefficiencies, many of which are related to a lack of competition among different types of capacity resources.

A. DESCRIPTION OF RESOURCE ADEQUACY PROVISIONS

California has three mechanisms for achieving resource adequacy within different timeframes: (1) the LTPP needs-determination process, under which the IOUs determine whether to solicit long-term contracts for new generation to meet projected system-wide needs, typically contracting 3-7 years prior to the facility's online date;⁶ (2) the Local and System RAR

⁵ See DSIRE (2012).

⁶ The LTPP process is also the mechanism under which IOUs can procure a portfolio of short-term and intermediate-term contracts for energy, capacity, fuels, and hedges on behalf of their bundled retail customers. However, the most important aspect of the LTPP for the purpose of this report is its long-term procurement process under which new generation is contracted if the IOUs' project a system-wide need in their service area (including both the IOUs' bundled customers as well as other LSEs' customers).

mechanism that requires all retail suppliers to procure sufficient capacity to meet their customers' capacity needs just prior to delivery; and (3) the CAISO's backstop reliability mechanism for curing any LSE capacity deficiencies under the RAR mechanism and preventing generation retirements that could introduce prospective resource adequacy concerns.⁷ The CPUC and CAISO are also currently considering enhancements to these mechanisms and to the CAISO's A/S markets to attract and retain sufficient flexible capacity resources.

1. Utility Long-Term Procurement Plans

In the aftermath of the Western power crisis, the CPUC assigned the IOUs the responsibility of procuring new generation supplies within their service territories through the LTPP process.⁸ The CPUC oversaw the IOUs' first biennial LTPP processes in 2004, and the 2012 LTPP proceedings are currently underway.⁹ The LTPP process begins with a 10-year outlook on supply, demand, and other system conditions, with the CPUC recommending extending that outlook to 20 years starting with the 2012 LTPP.¹⁰ Plans use this information for two purposes. The first purpose of the LTPP is to develop a short-and intermediate-term procurement plan that specifies how each utility will conduct procurement to meet its own bundled customers' needs at the lowest expected cost, including a portfolio of short-term and long-term energy, capacity, A/S, fuels, renewables, and hedging positions up to ten years forward.¹¹

A second, and for our purposes more important, aspect of the LTPP process is the long-term system-wide needs determination analysis, which determines whether and when the IOUs will contract to build new conventional generation resources.¹² This determination is based on *system* needs, including for the IOUs' own bundled customers as well as customers buying from competitive Electric Service Providers (ESPs) and Community Choice Aggregators (CCAs).

In analyzing whether new resources will be needed for system-wide resource adequacy, the IOUs incorporate substantial direction from the CPUC and input from stakeholders to develop detailed projections of future system and market conditions, including: (a) anticipated future peak load and average energy demand; (b) projected generation supplies after considering projected new builds, uprates, and renewable generation growth; (c) projected retirements, including those that may be driven by supplier economics and others driven by environmental policies such as the once-through-cooling mandate; (d) quantities of supply that may or may not be available through imports; (e) expectations about transmission infrastructure changes; (f) demand response and energy efficiency programs not already accounted for in the demand forecasts; (g) market price projections for fuels and carbon dioxide equivalent (CO₂e) emission allowances; (h) the need for flexible resources; and (i) other factors.¹³ Because these projections are highly uncertain, the CPUC requires that LTPPs consider several possible resource scenarios and develop a supply

⁷ Typical forward period of LTPP contracts based on a current summary of active PPAs procured under this mechanism. See CPUC (2012a).

⁸ See p. 26, CPUC (2007a), (2004a-b).

⁹ See CPUC (2012b).

¹⁰ See CPUC (2012c), p. 7.

¹¹ See the 2010 IOU LTPPs, CPUC (2012d); p. 8, CPUC (2012c).

¹² See, for example, Section 2.1 of CPUC (2007a).

¹³ See CPUC (2007a), (2012c).

plan that is likely to minimize customer costs after considering the multiple possible futures.¹⁴ Finally, the LTPP must consider certain other state policy objectives, including the “loading order” that requires procurement priority for EE, DR, renewables, and finally efficient fossil fuel in that order.¹⁵ Essentially, the LTPP determines whether there is any residual need for conventional generation after considering all projected DR, EE, and renewables.

Once a system-wide need for conventional new generation is identified, the IOUs implement competitive Request for Offers (RFO) processes to procure these resources.¹⁶ The RFOs stipulate certain contractual terms that suppliers must fulfill and resource characteristics that will be valued in the selection process. For example, RFOs may be limited to tolling contracts with certain start dates and terms.¹⁷ These contracts for new resources are typically signed 3-7 years in advance of delivery, with most contracts having a duration of 10 years, although IOUs have also contracted for durations of 20 and 25 years.¹⁸ In addition, some new generating resources may be procured under Purchase and Sale Agreements (PSAs) that result in utility ownership. Importantly, these RFOs stipulate that suppliers must fulfill contracts by developing new generation resources. The RFOs therefore explicitly exclude existing resources that may be able to fulfill the anticipated resource needs more cost-effectively. They also effectively assume that many existing resources will remain available to satisfy system needs even without a contractual commitment to stay online, although economics may pressure some of these resources into an unanticipated retirement. The result is that all new generation resources needed to serve customers of CPUC-jurisdictional LSEs in California are developed through long-term contracts or IOU ownership.¹⁹

Some new generating resources are procured on behalf of the IOUs’ bundled customers while others are procured on behalf of “all benefitting customers.” The costs of projects procured on behalf of all customers are allocated to all customers through non-bypassable charges.²⁰ To the extent that ESP and CCA customers are allocated the costs of a new resource, they are also awarded an appropriate share of the benefits, including the right to a portion of the associated capacity supplies. ESPs and CCAs can count these resources toward fulfilling their resource adequacy obligations as described in the following section.²¹

¹⁴ See pp. 5-7, CPUC (2012c).

¹⁵ See p. 5, CPUC (2007a).

¹⁶ Other bilateral procurement approaches are also approved in some circumstances. See, for example, Section II.A.5.b, PG&E (2011).

¹⁷ See, for example, the specifications identified in a Pacific Gas and Electric Company RFO for new resources from 2008, PG&E (2012a).

¹⁸ Specifically, of the current outstanding IOU PPAs for new conventional generation, six have a duration of 10 years, while one has a duration of 20 years and two have a duration of 25 years. See a current summary of active PPAs in CPUC (2012a).

¹⁹ Although exceptions will exist, for example, those resources developed to serve the load of non-CPUC jurisdictional entities.

²⁰ See p. 26, CPUC (2006b).

²¹ Associated costs and capacity rights are awarded to individual LSEs through an allocation methodology approved by the CPUC, see CPUC (2007b).

2. System and Locational Resource Adequacy Requirements

The CPUC introduced its RAR mechanism for assuring system-wide resource adequacy in 2004, and enhanced the mechanism to assure local resource adequacy in 2006.²² This mechanism requires each LSE under CPUC jurisdiction to procure sufficient capacity to meet its own customers' monthly projected peak load plus a 15% reserve margin requirement.²³ To reliably serve load within import-constrained load pockets, a certain quantity of capacity must be sourced from inside the constrained area to meet the area's Local Capacity Requirement (LCR).²⁴ Each LSE is therefore also assigned a local RAR obligation.²⁵

Each LSE must demonstrate that it has met its requirement by submitting a resource plan showing the quantity of capacity it has procured from individual capacity resources for each month. Supply plans are due in October for each month of the upcoming calendar year for 90% of system requirements in summer months and 100% of local requirements in all months; the plans must then be updated monthly just before delivery to demonstrate 100% of both requirements.²⁶ Any LSE that fails to procure sufficient system or local capacity supplies must pay a penalty *and* the cost of replacement capacity that CAISO will procure on their behalf.²⁷ Non-CPUC-jurisdictional entities in California within CAISO are covered under CAISO tariff provisions that mirror the obligation quantities specified in the CPUC RAR mechanism.²⁸ The RAR mechanism does not apply to non-CPUC-jurisdictional California utilities that are also not within the CAISO footprint, such as the Los Angeles Department of Water and Power (LADWP) or Sacramento Municipal Utility District (SMUD).

This RAR mechanism creates a short-term bilateral market for capacity resources, under which LSEs must self-supply or bilaterally procure sufficient capacity to fulfill their monthly resource requirements. A portion of an LSE's RAR obligation is fulfilled through the allocated capacity value of new resources procured under LTPP, utility DR programs, and any out-of-market capacity procured by CAISO.²⁹ The remaining RAR obligation must be fulfilled by procuring capacity from existing generation resources not already under contract to provide capacity to

²² See CPUC (2004c), (2006a).

²³ See p. 13, CPUC (2012e).

²⁴ The CAISO determines the quantity of capacity that must be sourced from within each load pocket by studying the quantity of available transmission capability into that load pocket during peak conditions. For example, see CAISO (2012a).

²⁵ Note that LSEs are assigned a share of local RAR obligations based on the total local obligations of all loads within the IOU's service territory, not based on the location of the LSE's individual customers. This approach creates some cost-shifting from customers inside load pockets to those outside load pockets, but the CPUC has determined that this concern is less important than the administrative costs that would be introduced by a more accurate local RAR allocation. See CPUC (2006a), Section 3.3.2.

²⁶ The five summer months are May-September, see pp. 2-4, CPUC (2012e).

²⁷ The penalties for local or system shortages are assessed on top of replacement costs unless the CPUC has granted a waiver of the LSE's local capacity requirements (a rarely-awarded exception that can be implemented in special circumstances including cases where it appears that only high local capacity prices are available due to the exercise of market power), see p. 4, Sections 3.3.10-12, CPUC (2006a).

²⁸ See CAISO (2012b), Section 40.

²⁹ See additional detail on CAISO backstop procurements in the following section. Also see CPUC (2012e), Section 3.

another entity. For this reason, existing generation resources (including plants that have cost-effective uprate or life-extension opportunities) can monetize the capacity value of their assets by selling capacity on a short-term bilateral basis to individual LSEs. However, these resources compete only against other existing generation resources to supply capacity; there is no mechanism by which uncommitted existing resources are able to compete with new generation resources to sell long-term capacity.

3. CAISO Backstop Capacity Procurement Mechanism

The CAISO also administers an out-of-market Capacity Procurement Mechanism (CPM) as a resource adequacy backstop.³⁰ In some cases, this mechanism is triggered because LSEs are deficient in meeting their local or system resource adequacy requirements as discussed above. In these cases, CAISO will procure sufficient capacity to resolve the deficiency and assign the costs to the deficient LSE. Assigning these backstop procurement costs plus an additional penalty to the deficient LSE is the enforcement mechanism for the market-based RAR obligation.

However, CAISO also has the authority to procure capacity under CPM on an out-of-market basis if needed for reliability reasons that are not already reflected in local or system RAR obligations. In 2011, the CAISO also gained the authority for forward intervention to prevent a generator retirement.³¹ Specifically, CAISO may engage in a forward CPM backstop if: (1) an existing generator informs CAISO through a binding affidavit that it will retire the unit unless it is awarded CPM status and payment; (2) the resource is not currently needed to meet collective local or system RAR needs and has therefore failed to earn a bilateral capacity payment; and (3) CAISO projects that the resource *will* be needed to meet RAR obligations within two years.³² Although CAISO has had this forward intervention authority for more than a year, it has not yet exercised it.³³ Further, a new CAISO proposal would extend its backstop authority to procure flexible resources that may be needed up to five years in the future.³⁴

³⁰ See CAISO (2012b), Section 43.

³¹ We do not discuss all of the possible conditions under which CAISO may award CPM payments to generators. However, for reference, we clarify that CAISO may award CPM payments if: (1) an LSE is deficient in meeting its local or system RAR obligations, requiring CAISO to engage in backstop procurements (as discussed above); (2) all LSEs have met their RAR obligations, but CAISO still anticipates a system or local deficiency for reliability purposes; (3) CAISO has identified a “Significant Event” which causes actual local or system needs to be substantially different from that anticipated at the time of the RAR studies, meaning that additional capacity on top of the effective system and local RAR obligations will be required; (4) CAISO has implemented “Exceptional Dispatch” procedures that manually dispatch certain units for reliability purposes on an out-of-market basis, thereby allowing that resource to elect to earn CPM payments for a minimum period of 1 month if that resource does not already have a capacity obligation; and (5) to prevent an anticipated retirement on a prospective basis (as discussed above). See CAISO (2012e), Section 2.5; CAISO (2012b), Section 43.

³² See CAISO (2012b), Section 43.2.6.

³³ A number of CPM designations have been implemented for other reasons, primarily for “Significant Events” and “Exceptional Dispatch” reasons as described in footnote 31. For a list of all implemented CPM designations, see CAISO (2011a), (2012f).

³⁴ There are a number of differences between the current CPM mechanism and the proposed mechanism for flexible resource retirement prevention, including that: (a) the flexible resources will be awarded unit-specific going-forward costs (rather than a uniform tariff-defined rate); and (b) the flexible resources

All out-of-market procurements can distort both energy markets and the bilateral RAR market, depressing prices for other generators, including aging units that may then need their own CPM payment to continue operating. The CAISO, CPUC, and many other market administrators have recognized the price distortive impacts of out-of-market reliability contracting, and they sometimes take measures to reduce this impact. For example, the CPUC has previously recognized the problematic impacts of non-market reliability must run (RMR) contracts, which was a key consideration in adopting local RAR in 2006.³⁵ The local RAR mechanism was very successful in reducing the need for RMR contracting, the cost of which decreased from \$259 million in 2006 to \$70 million in 2007.³⁶

Despite potential price-distortion impacts from out-of-market backstops, they are sometimes necessary to meet reliability needs that market mechanisms fail to adequately address. For example, if CAISO and CPUC wish to confirm with certainty that RAR obligations will be met over a two-year outlook, then a market-based RAR mechanism must also be enforced on a two-year forward basis (thereby avoiding the need for a forward-looking backstop mechanism). The current approach of requiring that resource adequacy be assured on a two-year forward basis while only enforcing RAR on a prompt basis is inconsistent, and will necessarily result in out-of-market backstop contracting. Finally, it is worth noting that not all backstop procurements are necessarily inefficient in themselves (e.g. if they prevent a retirement that a better-designed market construct would also have prevented), but they are problematic in any case because: (a) there is no mechanism for assuring that the procurement is the most cost-effective solution to the problem; and (b) even efficient backstop procurements can have inefficient collateral impacts on energy and RAR market prices.

4. CAISO and CPUC Efforts toward Meeting Flexible Resource Needs

The CAISO and CPUC are engaged in efforts aimed at ensuring that the system will continue to have sufficient flexible capacity resources to balance increasing amounts of intermittent renewable resources. Under the 2012 LTPP, IOUs will be required to consider flexible capacity needs, but there is not yet a formal approach for quantifying need on a long-term basis.³⁷ However, the CPUC expects to address this issue next year.³⁸

Concurrently, the CPUC is considering whether to incorporate flexible resource requirements into the short-term RAR process. Although the Commission opted not to implement such requirements under RAR for the 2013 delivery year, it indicated that an approach may be adopted for 2014.³⁹ The CAISO and CPUC Energy Division have proposed alternative

would not be counted toward RAR obligations in the prompt year, but would be encouraged to engage in capacity sales for RAR in all years after initial designation, and would remain eligible to receive payments sufficient to cover any going-forward costs in excess of their bilateral contract payments under RAR. See CAISO (2012g).

³⁵ See CPUC (2006a).

³⁶ See CAISO (2008), pp. 6.13-14.

³⁷ See CPUC (2012c), pp. 5-6, 15.

³⁸ See CPUC (2012h), p. 9.

³⁹ See CPUC (2012g), Section 3.2.2.

approaches for incorporating flexible resource requirements into the RAR program (without making RAR more forward-looking).⁴⁰ The CAISO has also recently presented an updated proposal.⁴¹

Finally, the CAISO is pursuing its Flexible Capacity Procurement stakeholder initiative. Phase 1 of CAISO's effort is focused on developing an out-of-market backstop for flexible resources at risk of retirement based on a five-year forward determination of need. Phase 2 is intended to develop a complement for whatever explicit intermediate-term flexible capacity procurement requirements the CPUC introduces through LTPP or RAR.⁴²

B. INEFFICIENCIES INTRODUCED UNDER THE CURRENT FRAMEWORK

California's current resource adequacy framework, implemented through the three inter-related constructs described in the previous section, produces a number of inefficiencies. Many of these inefficiencies stem from the fact that these mechanisms are not integrated in a manner that fosters competition among different types of capacity resources.

1. Price Discrepancies among Different Types of Capacity Resources

Different types of resources may have very different market values based on their age, efficiency, fuel cost, flexibility, and expected life. The differences in asset value reflect the fact that some types of assets may earn substantial net revenues from energy and A/S markets while other assets, such as DR, may earn little or no energy and A/S revenue; they can also reflect substantial differences in the asset's remaining. However, the resource adequacy value that any particular asset provides during a particular delivery period is independent of differences in these other asset characteristics. Each asset's resource adequacy value is determined by its contribution toward meeting system peak and local reliability requirements after accounting for availability patterns. Just as the price a tomato farmer receives for his tomatoes does not depend on the type or age of his tractor, the payment that a capacity resource receives for its resource adequacy value should not be a function of unrelated attributes.⁴³ Because these resources are interchangeable within any particular year for meeting the reserve margin requirement, an efficiently competitive market construct should award all resources the same capacity payment for making the same contribution toward resource adequacy.⁴⁴

As we explain below, there are a number of aspects of the California resource adequacy framework that prevent competition among different types of capacity resources. Figure 1 illustrates this lack of competition by showing the large discrepancy in capacity prices and

⁴⁰ *Id.*

⁴¹ See CAISO (2012h).

⁴² See CAISO (2012e).

⁴³ Note that this paradigm does not apply in cost-of-service regulated industries. Under cost-of-service regulation, the price charged for a power plant is determined by its accounting costs. As a result, the regulated annual revenue requirements associated with new plants will generally be higher than those of old plants, at least until major capital additions are needed at the old plant. This declining revenue profile for power plants in a cost-of-service regulated environment does not exist in competitive markets.

⁴⁴ Still, as noted, the assets may nevertheless have very different total values given their fixed and variable costs, and different revenue streams for energy, ancillary services, and renewable energy credits.

payments available to different types of resources including: (a) short-term RAR construct payments available on a bilateral basis to existing generation resources that are not under long-term PPAs; (b) new generation resources developed under regulated contracts or cost recovery through the LTPP process; (c) utility demand response programs, which are evaluated according to cost-effectiveness tests including avoided capacity costs; and (d) generation resources contracted under CPM, the tariff payments for which were set based on an estimate of the net going-forward costs of a generic new resource for some years or under a black box settlement for other years.⁴⁵ A lack of price transparency makes it difficult to compare capacity prices across different asset classes including for the same delivery years, but we have attempted to make this comparison as equivalent as possible.

The lack of competition is particularly obvious when comparing prices available to existing and new resources. Existing resources that are not under long-term contract may be able to sell their capacity only at median prices of \$18-38/kW-year under the RAR construct, although some existing plants are likely to earn those prices only during the summer peak month(s) and may be unable to sell their capacity for many months of the year. In the example of a resource that is only able to sell capacity for one summer peak month, that facility may be able to earn only \$1-3/kW-year in capacity revenues; a resource contracting for all five summer months would earn approximately \$8-16/kW-year. For simplicity, in the remainder of this report we will assume that existing generators can earn capacity payments over all twelve months, but we clarify here that this is a high-end estimate.

In stark contrast, new generation developed under LTPP may be awarded PPAs at rates equivalent to capacity payments of approximately \$150-300/kW-year (excluding approximate net energy and A/S value). Publicly-available data on these contractual terms are sparse, making it difficult to accurately estimate what contract payments have been made for new plants. However, we have gathered some limited information on the revenue requirements of the proposed Oakley plant agreement that is currently under CPUC review, as well as the Colusa plant that came online in 2010. We estimate that the proposed Oakley plant tolling agreement might include the equivalent of capacity payments at approximately \$300/kW-year in 2016, dropping to \$220/kW-year in 2023. This estimate is based on tolling payments sufficient to meet the plant's revenue requirement of \$275-360/kW-year, after netting out an approximate combined cycle (CC) energy and A/S margin of \$60/kW-year.⁴⁶ Using a similar calculation, we estimate that the Colusa plant might be earning the equivalent to capacity payments of approximately \$150/kW-year, effective for its first delivery year of 2010. While it is technically possible that prices for different types of capacity procurement could converge to a levelized estimate of Oakley's costs by the time Oakley enters service, this outcome seems highly unlikely given the very low recent prevailing prices in the bilateral RAR market and the near-term outlook for supply excess.⁴⁷

Further, utility demand response program developments are evaluated against an approximate "capacity value" currently set at an administratively-calculated level of \$136/kW-year, which is

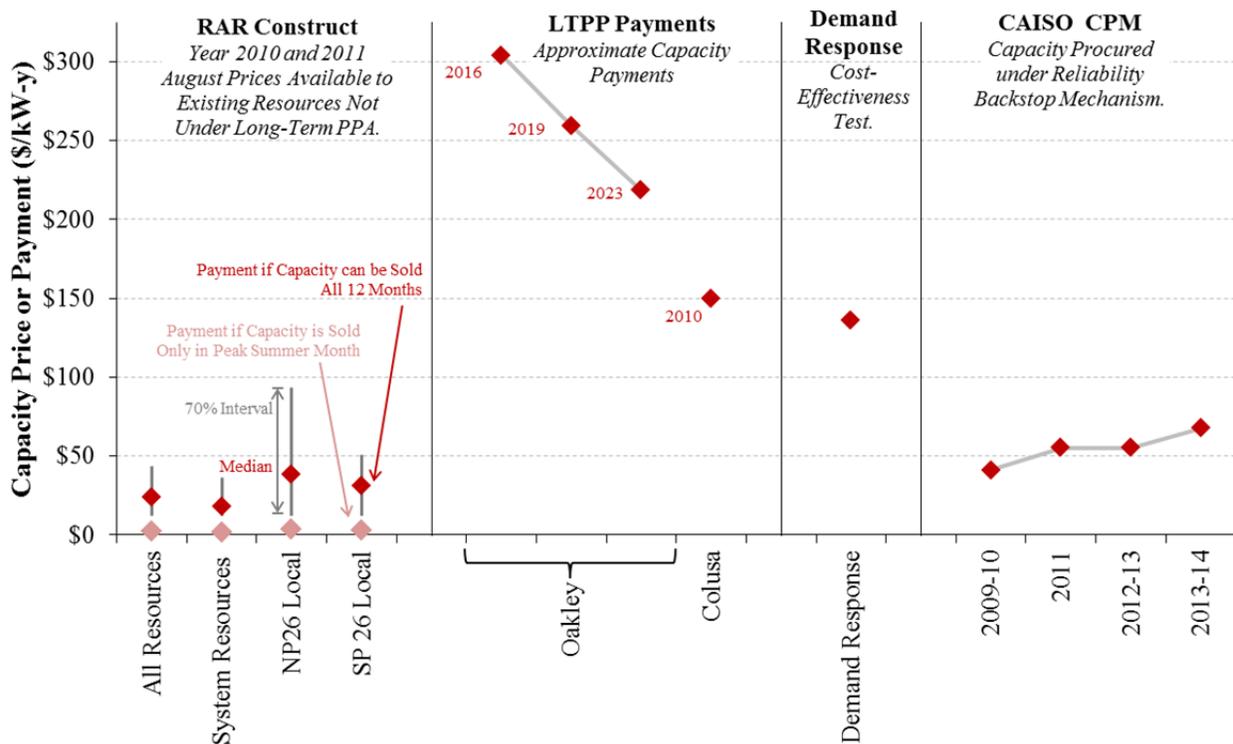
⁴⁵ See FERC (2012), pp. 2, 4.

⁴⁶ Source data contained in footnotes of Figure 1.

⁴⁷ See, for example, a CAISO analysis indicating that the Sutter plant would not be needed for resource adequacy or flexible resource characteristics until 2017/2018, CAISO (2011c).

far above the current cost of procuring alternative capacity supplies under the RAR construct. Finally, CAISO’s CPM backstop payments are set at an administrative level of \$41-71/kW-year (depending on the year), which also exceeds the cost of alternative capacity supplies under RAR.

Figure 1
Comparison of Capacity Prices and Payments under Various California Mechanisms



Sources and Notes:

- Bilateral prices under RAR represent contracts effective in Aug. 2010 and Aug. 2011, covering all types of short- and long-term contracts. Some contracts may also be effective only for a single month or part of a year and would therefore provide annual revenues substantially below those reported. See CPUC (2011a), Section 4.3.
- Oakley payments are based on the unit’s annual revenue requirements over 2016-23 as filed with the CPUC and applied over a plant rating of 614 MW. To estimate an implied capacity payment, the revenue requirement is reduced by approximate energy and ancillary service (E&A/S) offset of \$58/kW-y based on the average E&A/S margin for a CC in NP15 over 2007-11. See CAISO (2012c), Section 1.3; PG&E (2012b), Table 6-3.
- Colusa plant capital cost is \$684 million as reported by the CPUC. We assume that the plant has a similar financing and FOM structure to Oakley, and therefore assume the same ratio of annual revenue requirements to capital cost, with the first year revenue requirement being 19% of capital costs. As with Oakley, we assume an E&A/S offset of \$58/kW-y, with costs applied over the 630 MW summer plant rating. See CAISO (2012c), Section 1.3; CPUC (2011c), (2008), p. 4; Monsen (2012), p. 10; PG&E (2012b), Table 6-3.
- Demand response cost-effectiveness test from the “Residual Capacity Value” estimate in CPUC (2011b).
- CPM construct payments are as stipulated in the CAISO Tariff (or previous versions of the Tariff) for each year, and are subject to a monthly shaping factor CAISO (2012b), Section 43.7.1.

Notwithstanding the fact that the prices summarized in Figure 1 reflect different delivery years and terms, the extreme price differences summarized in the figure indicate the potential for substantial market inefficiencies resulting from the lack of competition among different types of resources, including low-cost existing generation, aging generators facing reinvestment costs,

generation upgrades, imports, new generation, and independently-provided “merchant” demand response.

If these different types of capacity suppliers were able to compete directly against each other to supply California’s resource adequacy needs, then significant price differentials should not exist. An integrated, market-based approach would procure incremental needed supplies from the lowest-cost capacity resources, no matter the resource type. This approach would also reduce total system and customer costs in the long-term by encouraging the most cost-effective investments and postponing the need for investments in higher-cost new generation resources, as we explain further in Section III.A.

2. Lack of Competition between New and Existing Resources

In California, new generation investments are driven by the LTPP process while existing resources without contracts or whose PPAs have expired are able to sell their capacity only through the bilateral RAR market. To meet RAR requirements, LSEs may bilaterally procure RAR capacity up to several years forward in anticipation of future RAR obligations, although forward contracting is likely quite limited among ESPs and CCAs that are not sure what their future customer base will be. On the other hand, IOUs’ procurement plans for bundled customers include explicit hedging strategies covering delivery years up to five years forward, but do not necessarily obligate the IOUs to procure capacity on a multi-year forward basis.

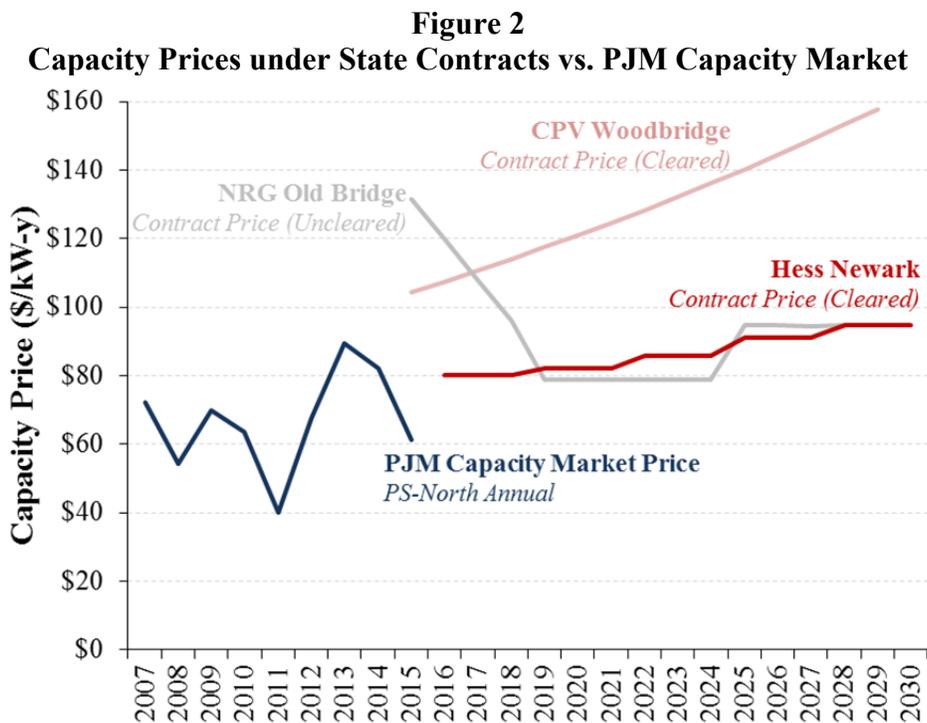
As demonstrated in Figure 1 above, there is a substantial cost differential for procuring capacity from new and existing resources, with new resources being contracted at five to ten times the price of procuring existing resources. Such an extreme price differential indicates a substantial market inefficiency that is increasing system and customer costs in the long-term by favoring contracts with new resources even if their costs far exceed the cost of procuring incremental capacity from alternative uncommitted sources of supply. Currently, California has no mechanism that allows for direct competition between new and existing resources to ensure that long-term procurement processes are selecting the lowest-cost supplies.

Discriminatory procurement practices, including the RFOs conducted to meet LTPP-identified needs, will produce inefficient outcomes if they preclude competition from lower-cost alternatives. Existing resources (including incremental imports) can often be the lowest-cost supply resources because they may be able to re-contract for a number of years without the major investments needed for new plants, make relatively inexpensive upgrades to increase a plant’s rating, or cost-effectively reinvest in an aging facility to extend its useful life. Procuring more incremental capacity supplies from these low-cost sources would postpone the need for building high-cost new fossil generation. In addition, the fact that new resources will anticipate tremendous reduction in capacity-related revenues after their PPAs expire will require them to offer at higher contract prices. These new generators will require that most or all of their investment costs be recovered during the usual 10-year PPA duration. Over time, these higher-price PPAs for new generation will more than offset any “customer savings” that appear to be associated with paying less for existing generating capacity.

We observed similar concerns in PJM, where the states of New Jersey and Maryland required utilities to sign long-term supply contracts for new generation that have proven far more expensive than alternative supplies available through the capacity market, including new

generation that cleared the capacity market on a merchant basis. In both states, the Commissions and other stakeholders were concerned that the PJM capacity market would not procure sufficient capacity resources to meet reliability objectives, and that the market would not be able to attract new generation resources at a reasonable cost.⁴⁸ The state is therefore engaged in discriminatory solicitations to contract with 1,950 MW of new generation in New Jersey and 660 MW in Maryland.⁴⁹

In retrospect, the New Jersey contracts have proven to be very expensive relative to alternative sources of supply, while the Maryland contract price has not been publicly reported. As shown in Figure 2, the two New Jersey plants that cleared the auction have contract prices at a premium of 31% and 71% above the \$60/kW-year 2015/16 PJM capacity market clearing price, with the contract payments increasing over time. The NRG Old Bridge resource contract price is similarly above market, but because the resource did not clear PJM’s capacity auction the contract will not go into effect as planned for 2015/16.



Sources and Notes:

PJM price represents annual resource price starting 2014/15. Prices converted to \$/kW-year from \$/MW-day. PS-North prices shown starting 2012/13, earlier year prices are for parent Locational Deliverability Areas (LDAs), see PJM (2012a). Contract prices from PSEG (2011a, b), SNL Energy (2012).

The fact that two of these contracted plants cleared the PJM capacity market at such a low price also indicates that the contract payments are substantially above the units’ actual costs. This is because PJM’s mitigation provisions impose a Minimum Offer Price Rule (MOPR) requiring

⁴⁸ For Example, see Marrin (2011).
⁴⁹ See Levitan (2011); Roach, *et al.* (2012).

proof that new gas generation offer prices are at or above their demonstrated costs. The PJM market monitor therefore verified the units' actual costs, which must have been at or below the \$60/kW-year clearing price, meaning that the New Jersey contracts were signed at prices far above the units' actual costs.⁵⁰ As discussed below, two major merchant plants without long-term contracts also cleared at the \$60/kW-year capacity price.

3. Uneconomic New Generation Investments Driven by Planning Uncertainties

Part of the reason that procurement processes limited to new generation resources can prove to be uneconomic is that there is a substantial uncertainty in the outlook for how much new generation might be needed, as well as uncertainty in the costs of potential alternatives. A regulatory or utility planning process such as LTPP relies on a number of assumptions including: (a) which existing units are likely to retire over time; (b) long-term load forecast; (c) the level of locational capacity additions from renewable generation, DR, and EE programs; (d) available capacity imports; and (e) a number of other factors. The CPUC recognizes that these uncertainties exist and therefore requires the IOUs to consider a number of future scenarios.⁵¹ However, because these uncertainties are ultimately unresolvable, they necessarily result in an inaccurate determination of the quantity of new generation capacity that will be needed.

To the extent that LTPP projections are incorrect, they will impose excess system costs and customer costs. For example, overstated retirement projections will result in excess procurement of costly new generation, while understated retirement projections could result in under-procurement and the ultimate need for potentially expensive backstop reliability procurements under CPM.

A major source of uncertainty is that most decisions to retire, retrofit, uprate, or otherwise reinvest in existing facilities are made by independent power producers, leaving utilities in a position where they can only guess at the likely outcome, a concern that the CPUC has previously noted.⁵² A decision of whether to retire or reinvest in a facility is ultimately an economic decision that is best made by the plant owner after considering the outlook for market prices weighed against reinvestment and other ongoing costs. In some cases, it is hard for even the plant owner to determine whether a reinvestment will be cost-effective; IOUs and other LTPP participants have even less ability to make that determination. Given these uncertainties, utility LTPPs may easily over-estimate retirement levels, resulting in the uneconomic development of high-cost and unneeded new generation supplies.⁵³ For example, the IOU

⁵⁰ We attribute the discrepancy between the plants' higher offers in the New Jersey long-term procurement solicitation and their actual costs to the fact that the pay-as-bid format of the long-term procurement induced the plants' developers to offer those plants at projected market prices, just below what other potential new generators might offer into that solicitation auction. Given the small number of suppliers that could offer into that new generation solicitation, it appears that there was limited competition for these large capacity contracts. In contrast, the uniform clearing price format of the PJM capacity auction with substantial competition from many types of capacity suppliers allows all participants (including new generators) to offer at their actual going-forward costs, but earn the market price if they clear.

⁵¹ See CPUC (2012c), pp. 6-7.

⁵² See CPUC (2007a), Section 2.4.

⁵³ The same uncertainty could also easily lead to understated retirement projections, although we have not observed an example of this, possibly due to a planning bias toward conservatism.

LTPPs approved in 2007 incorporated a California Energy Commission (CEC) retirement projection of 50 aging plants totaling 14,000 MW of capacity between 2008 and 2012.⁵⁴ This projection has proved to be a large over-forecast as, in reality, only approximately 3,000 MW have retired over that period.⁵⁵

Another concern is the difficulty in identifying the most cost-effective plant reinvestments under utilities' procurement plans. Occasionally, major uprate and repowering projects compete in utility RFOs, but there is not a straightforward approach for evaluating the cost-effectiveness of these projects compared to new generation.⁵⁶ Further, there is no systematic process for identifying all cost-effective re-contract, upgrade, retrofit, and repowering opportunities that might be available in the existing fleet. Part of the problem is that neither utilities nor regulators have the most accurate information about the costs of these investment options, owners' and developers' views about future market revenues, or about suppliers' willingness to accept market risks. The only way to identify most of these opportunities would be through open solicitations that do not discriminate between new and existing resources.

Uneconomic, high retirement assumptions may even become a self-fulfilling prophecy, because procuring unneeded new generation will depress energy and short-term capacity prices below competitive levels and will therefore tend to drive inefficient additional retirements. In contrast, if existing and new resources could directly compete with each other to supply the needed capacity, then asset owners themselves would evaluate the economics of retirement or reinvest decisions. In this case, competitive forces would select the most cost-effective mix of investments in new generation and reinvestments in existing generation. In addition, a non-discriminatory forward procurement process would solve the problem of having to guess at future retirement levels by securing economic repowering and reinvestment opportunities, while enabling the retirement of resources that would be very costly to maintain.

4. Potential for Inefficient Once-through-Cooling Replacements and Retrofits

The risk of inaccurate or uneconomic retirement forecasts is amplified by the new once-through-cooling rules affecting approximately 16,000 MW of generation over the next decade.⁵⁷ Each of the affected plants will have to evaluate its compliance options, and identify the lowest-cost reinvestment option available for meeting the mandate. Once the owner has determined its most attractive compliance option, it is faced with a decision of whether to reinvest in the facility or retire the unit. From the owner's perspective, the retire-or-retrofit decision will be based on a forward-looking assessment of whether future profits will be sufficient to cover the retrofit costs. From a system-wide cost and efficiency perspective, the best retire-or-retrofit decision should be made after considering whether the retrofit is lower-cost than alternative sources of supply. The

⁵⁴ See CPUC (2007a), Section 2.4.

⁵⁵ Based on the summer capacity of all plants in CAISO listed with retirements dates over 2008-2012. Ventyx (2012).

⁵⁶ For example, in a recent PG&E contract application covering both existing capacity and an uprate, some commenters asserted that the costs of the contract should be weighed against only the uprate, while others asserted that the entire contract capacity should be considered. See CPUC (2010b), Section 6.5.

⁵⁷ Based on an analysis of individual units' compliance dates and summer capacity, excluding resources with compliance dates prior to 2012 (which have already retired or complied), and excluding resources with compliance dates after 2022. Data from SNL Energy (2012); SWRCB (2012); CAISO (2010).

lack of a competitive mechanism for evaluating these retrofit opportunities against alternative supplies makes it very difficult to project what fraction of these units will ultimately retire and what fraction (if any) may be able to cost-effectively reinvest to comply with the regulation.

In fact, there is so little information about which plants will ultimately retire that the CPUC has proposed that utilities consider extreme alternative cases in which: (1) either none or all of the resources pursuing the “Track 2” compliance option retire; and (2) either both or neither of two large nuclear plants retire by 2015.⁵⁸ Even considering only the 4,500 MW of nuclear capacity at risk, having inaccurate retirement projections could result in the utilities procuring capacity from seven large new gas combined cycle facilities that may or may not ultimately be needed.

As discussed earlier, such large uncertainties in retirement forecasts will necessarily lead to uneconomic investment decisions and add to the other uncertainties in determining local and system reliability needs including load forecast, projected DR and EE growth, load growth, and distributed generation. The best way to determine which of these units can be upgraded cost-effectively is to allow them to compete with other existing resources, potential new generation, demand-side resources, and imports to meet future system-wide and local resource adequacy needs. Such a competitive mechanism would enable an explicit comparison among these alternative sources of supply to determine the lowest-cost means of achieving California’s reliability objectives.

5. Forward Backstop Mechanisms that Could Preempt Market Alternatives

As discussed in Section II.A.3 above, out-of-market reliability interventions distort market prices because they support a select subset of generators that will then continue operating. Continuing to operate these generators suppresses energy and RAR capacity prices available to other suppliers. This is a particular problem with the forward-looking CPM option that allows the CAISO to procure capacity from generating units that state their intentions to retire, although we note that the CAISO has not yet exercised its new authority to intervene in this way.⁵⁹

Because the CPM can be implemented up to two years forward, CAISO must evaluate on a forward basis whether a local or system adequacy concern is likely to arise. The problem with this approach is that if CAISO *does* award a CPM designation on a forward basis, it will preempt potential market-based alternatives and introduce the risk of administrative error in the needs assessment. Any CPM capacity procured is allocated to LSEs, reducing their procurement requirement as well as the overall market demand and prices for short-term capacity. This discourages the market-based development of alternative incremental capacity supplies, including uprates to existing units that may be lower-cost than the CPM contract (but costly enough that the suppressed energy and RAR capacity prices are insufficient to support them).

⁵⁸ “Track 2” compliance refers to the compliance approach where the plant owner will seek alternative means to reduce their impact on aquatic life to avoid having to install cooling towers. See CPUC (2012c), pp.20-22; SWRCB (2012).

⁵⁹ However a number of CPM designations have been implemented for other reasons, primarily for “Significant Events” and “Exceptional Dispatch” reasons as described in footnote 31 above. For a list of all implemented CPM designations, see CAISO (2011a), (2012f).

Further, CPM resources are awarded capacity payments at a fixed, tariff-defined rate that does not reflect market conditions and may be higher than the cost of alternative options. In fact, as explained in Section II.B.1, short-term capacity suppliers only earn approximately \$18-38/kW-year depending on the location, while the CAISO tariff rate for CPM is substantially higher at \$41-71/kW-year, depending on the year. Based on this evidence, it appears likely that an open solicitation to prevent the same anticipated shortage on a forward basis could result in procuring sufficient capacity supplies at lower cost than the rate stipulated by the Tariff. However, if CAISO and CPUC wish to confirm with certainty that resource adequacy and flexible resource needs will be met on a two- or five-year forward basis, they only ways to achieve this objective are: (1) through out-of-market mechanisms such as CPM, that have the potential to introduce substantial inefficiencies and distort market prices; or (2) impose market-based RAR or flexibility obligations on a *forward* basis, thereby relying on market forces to assure that the lowest-cost resources are selected to meet the forward-looking reliability needs.

6. Inefficient Cost-Effectiveness Tests for Demand Response

Another inefficiency in California's resource adequacy framework relates to how the CPUC assesses the cost-effectiveness of IOU demand response programs.⁶⁰ The primary economic value of demand response is that it reduces peak load, contributing to resource adequacy and preventing the need to procure higher-cost capacity supplies. However, current CPUC rules stipulate that DR cost-effectiveness be evaluated against an administratively-estimated long-run equilibrium cost of capacity supply. This long-run cost is estimated as the annualized capital cost of building a new CT, less the estimated net energy and A/S revenues that supplier would earn from CAISO's markets.⁶¹

Currently, the CPUC's stipulated rate for calculating avoided capacity costs is at an estimated net CONE of \$136/kW-year.⁶² However, actual avoided capacity costs are approximately \$18-38/kW-year under current RAR market conditions, or only a fraction of the administratively-calculated avoided capacity cost. The current price for alternative capacity supplies is so low because the market is not in a long-term equilibrium, but instead experiences an over-supply of capacity that has suppressed capacity prices well below net CONE.⁶³ Selecting DR programs based on a much higher long-term equilibrium benchmark price could result in customers paying for DR programs whose costs exceed the customer benefits.

As reserve margins tighten in the future, this administrative cost test could actually under-value DR relative to market conditions. If California were to face a capacity shortage, then short-term capacity payments to DR resources should be allowed to rise above the administrative net CONE, consistent with market conditions. Finally, even when California *is* in long-run equilibrium, the administrative net CONE calculation will be subject to administrative error and

⁶⁰ See CPUC (2010a), pp. 21-25.

⁶¹ A similar administratively-calculated net cost of new entry (CONE) is also used in other markets such as PJM, NYISO, and ISO-NE for various purposes.

⁶² See the "Residual Capacity Value" estimate in CPUC (2011b).

⁶³ For example, the California Energy Commission's 2012 Summer Outlook projected a reserve margin of 30% at summer peak under a 50/50 peak load estimate, compared to the reliability requirement target of 15%. See CEC (2012), p. 2.

may deviate from actual avoided capacity costs. A better approach to valuing DR capacity would be to evaluate it against actual current capacity prices under the RAR mechanism, including allowing merchant DR developers to monetize this value as discussed in the next section.

7. Difficulty in Attracting Third-Party Demand Response

While California has made substantial progress in developing utility-sponsored DR programs, it has no effective mechanism for attracting or rewarding third-party, merchant DR development. In other markets, we have observed that enabling curtailment service providers (CSPs) who independently invest in DR programs can lead to a large influx of low-cost capacity resources as explained further in Section III.A.2. Enabling DR suppliers to compete for capacity contracts and earn capacity payments on equal competitive terms with generation suppliers created strong incentives to mobilize DR developers. For example, PJM has attracted DR commitments sufficient to meet 10% of its peak load by 2015/16.⁶⁴ Rapid DR growth has also substantially mitigated the cost and reliability impacts of coal plant retirements in PJM in response to environmental regulations as discussed in Section III.B.2.

California will be unlikely to attract similar large quantities of merchant DR development unless there are mechanisms that enable third-party suppliers to monetize the capacity value of their resources. Mechanisms enabling merchant DR providers to participate in CAISO's energy and A/S markets are also beneficial, but capacity payments are more important because its resource adequacy contribution represents the vast majority of a DR resource's value.

The CPUC has recognized the need to enable third-party DR development in a recent ruling, where it indicated an interest in moving away from relying solely on a utility-sponsored approach to DR development.⁶⁵ Implementation details and timing of a move toward third-party DR development are yet to be fleshed out, but the CPUC indicated that it may favor a model where utilities procure DR through competitive solicitations.⁶⁶

However, it is not clear that the CPUC's revised approach to third-party DR development will enable large quantities of competitive entry similar to what eastern capacity markets have attracted. A key aspect of enabling merchant DR is creating an avenue for CSPs to monetize the capacity value of their peak load reductions without going through the utilities that often compete with CSPs. Rather than competing in utility solicitations, merchant DR providers could be allowed to qualify as capacity directly with CAISO by satisfying any stipulated technical and other qualification requirements. The merchant DR resource could then sell its capacity under the RAR construct to any utility, ESP, or CCA for meeting its local or system capacity requirement just as a qualified generator would. These DR suppliers could also sell their capacity to municipalities that are not under CPUC jurisdiction, but that must meet the same RAR requirements under the CAISO tariff.

⁶⁴ Based on 15,755 MW of cleared demand resources in the 2015/16 Base Residual Auction, see PJM (2012a), 2015/16 Base Residual Auction Report, p 11; Planning Period Parameters Report, p. 4.

⁶⁵ See CPUC (2012f), Section 8.2.

⁶⁶ Developing these mechanisms is now deferred to a separate CPUC docket, R.07.01-041.

Under this approach, the attractiveness of DR investments would be efficiently tied to the true value of capacity under current market conditions. For example, if unexpected resource shortages were to arise, merchant DR developers would be in a position to quickly develop new assets to capture high short-term capacity prices.

8. Lack of Liquidity and Transparency in Short-Term Bilateral Transactions

One final concern is a lack of liquidity and transparency in the short-term market supporting the RAR construct. While the RAR construct has the beneficial attribute that it is a market-based mechanism fostering competition to meet local and system adequacy needs, its efficiency is impeded by its sole reliance on bilateral contracting. Bilateral markets are, by their nature, less transparent and may have higher transactions costs than centralized auction-based markets and over-the-counter exchanges.

There is currently little public information and no exchange platform enabling short-term bilateral exchange of RAR resources in California. This leaves market participants with less information with which to: (a) determine the value of a potential reinvestments in existing generation that could produce incremental capacity supply; (b) inform bilateral negotiations over capacity to meet RAR obligations; or (c) find counterparties for potential transactions (including small transactions for only a portion of a resource). For example, the lack of transparency may result in an LSE holding excess capacity resources rather than expending the effort to identify another buyer. If it were easier to sell off such excesses through a simple exchange or auction platform, then we would expect incremental supplies to be more readily available to buyers, thereby reducing prices in some cases.

III. THE VALUE OF MARKET-BASED RESOURCE ADEQUACY MECHANISMS

Most of the inefficiencies identified in California's resource adequacy construct stem from a reliance on uncertain administrative planning projections and non-market mechanisms. Replacing these mechanisms with market-based approaches to achieving reliability and other policy objectives will increase competition and incentivize the marketplace to identify the lowest-cost options for achieving those objectives. Non-discriminatory capacity procurement, particularly if implemented on a *forward* basis, can significantly reduce the costs of meeting reliability objectives.

A. NON-DISCRIMINATORY CAPACITY PROCUREMENT

Non-discriminatory capacity procurement enables competition among existing and new generation, uprates, imports, DR, and EE. Procurement that is not limited to a particular type of resource, but is instead open to the entire pool of potential suppliers, will achieve resource adequacy objectives at the lowest cost.

1. Advantages of Non-Discriminatory Capacity Procurement

There are a number of inefficiencies introduced by discriminatory capacity procurements that solicit capacity commitments from only new generating plants while excluding competition from existing resources, as discussed in Section II.B.2. Discriminatory procurement practices

preclude efficient competition and investment tradeoffs. In contrast, non-discriminatory procurement processes that enable full competition between new and existing capacity will procure the lowest-cost supplies, minimize total system costs, and often postpone the need for investments in costly new generating plants. A summary of the advantages and disadvantages of each approach is presented in Table 1.

Table 1
Pros and Cons of Discriminatory and Non-Discriminatory Procurement

Option	Advantages	Disadvantages
<p>Discriminatory Procurement</p> <ul style="list-style-type: none"> - Procure capacity commitments from new resources separately from existing resources - Allow higher prices for new resources 	<ul style="list-style-type: none"> - Careful, strategic implementation may create net customer benefits (only in the short-term) by suppressing energy and capacity prices for existing suppliers - Allay fears that new generation might not get built under a shorter-term market-based framework 	<ul style="list-style-type: none"> - Energy and capacity price suppression benefits are temporary, achieved at the expense of existing suppliers - Price suppression is only achieved if new generation is procured in excess of need - Missed opportunities to procure lower-cost existing assets, DR, and imports, increasing total system costs - Price suppression benefits eroded as suppressed prices for existing suppliers lead to greater retirement, requiring even more new generation to be built through above-market contracts (or existing generation retained through above-market payments) - Price suppression to existing gen perceived by investors as increased regulatory risk - In a price-suppression environment, no new generation will be built without above-market contracts and new generators will demand higher prices to compensate for suppressed prices after contract expiration - Inefficiencies increase long-run customer costs - Customers bear risk of uneconomic investment decisions and planning uncertainties by signing above-market long-term contracts
<p>Non-Discriminatory Procurement</p> <ul style="list-style-type: none"> - Single procurement mechanism for all new and existing resources (one capacity price) 	<ul style="list-style-type: none"> - Lowest-cost capacity supplies procured, minimizing system costs - Attracts unconventional sources of new supply including DR, uprates, and imports that would not otherwise have been identified. (Other markets have attracted large quantities of such low-cost supplies, see Section III.A.2.) - Suppliers with the best information on resource costs bear the risk of uneconomic investments based on their own projections of market conditions 	<ul style="list-style-type: none"> - Easier to implement non-discriminatory procurement with short- and intermediate-term contracts, but generation developers prefer long-term PPAs that reduce their risks and financing costs (shifting risks to the buyer)

Despite the substantial disadvantages of discriminatory procurement practices, however, some regulators and market participants find such practices appealing for a number of reasons. One common reason that state regulators and load interests favor separate procurements for new generation is to differentiate prices awarded to new and existing resources. Price discrimination strategies aim to pay high prices only to new generators such that they can cover their investment costs, while reducing prices for existing generators whose investment costs are already sunk. In this case, procuring new generation at above-market costs can reduce energy and capacity costs to ratepayers (at least in the short run) as long as the new supply creates excess capacity and suppresses energy and capacity prices enough to offset the above-market contract costs. However, such price discrimination can only benefit ratepayers for a limited period of time before the customer benefits are eroded and outweighed by investment inefficiencies. These resulting investment inefficiencies and higher investment costs will lead to higher customer costs in the long run. Further, these price suppression benefits are achieved at the expense of existing generators that may therefore be unable to recover their investment costs. This dynamic creates higher cost recovery risks that will deter merchant generation investments.

Customers can only benefit from price discrimination for a limited period of time because the lack of payments to existing generators will result in earlier retirements, fewer uprates of existing resources, fewer imports, and less supply from other capacity resources.⁶⁷ Underinvestment in existing generation will reduce supply and increase energy and capacity prices, undoing some of the price suppression from the new generation. For suppressed energy and capacity prices to persist, ever greater levels of new generation would have to be added prematurely. Contract prices for these premature new investments also will be substantially higher than the cost of retaining existing supply for two reasons. First, the lack of payments to existing generators means that resources with much lower cost than replacement capacity will retire inefficiently. Second, new generators coming online will expect to receive low prices once their contracts end, as they and their investors will strongly discount potential non-contract revenues under the current price-discrimination environment. They will therefore demand contract payments high enough to cover most of their investment costs while still under PPA. The bottom line is that total costs to customers will necessarily be higher in the long-run if low-cost opportunities to reinvest in existing facilities are foregone in favor of higher-cost new resources.⁶⁸

Existing generation cannot be retained efficiently unless capacity prices for existing resources are allowed to rise to the same prices paid to all resources. Only then can cost-effective tradeoffs be made between maintaining existing capacity and building new capacity. Many existing generators have low going-forward costs, but some have higher ongoing costs (*e.g.*, high annual repair, refurbishment, and maintenance costs) as well as occasional substantial investments (*e.g.*, environmental retrofits or replacements of major plant components). Particularly if an existing plant does not earn high energy margins, its net cost of providing capacity for resource adequacy

⁶⁷ For example, our review of PJM's capacity market has shown that the introduction of non-discriminatory capacity procurement reduced the level of retirements from 500 MW and 3,500 MW each year to a range of zero to 500 MW. See Pfeifenberger and Newell, *et al.* (2008), p. 20.

⁶⁸ For a case study of the adverse consequences of imposing different prices for "new" and "old" resources, refer to the discussion of inefficiencies, reduced investment incentives, and overall welfare losses resulting from the different regulation of prices for "old" and "new" natural gas prior to the implementation of the Natural Gas Policy Act of 1978 as discussed in Viscusi, Vernon, and Harrinton (2000), pp. 616-632.

purposes may be higher or lower than the net costs of new generation. The only way to identify the resources with the lowest net going-forward costs is to have them compete and face the same capacity price.

PJM's non-discriminatory forward capacity auctions have demonstrated how new and existing resources compete. Far more existing capacity clears than new, but some existing generation fails to clear because it is not competitive with alternative supplies, including new resources. For example, in PJM's auction for the 2011-12 delivery year, a total of 2,144 MW of new capacity cleared in the auction, while 497 MW of new generation did not clear. In comparison, 4,049 MW of existing capacity did not clear even though the bid prices for the existing resources were mitigated to reflect their net going-forward costs.⁶⁹ As these data show, the all-in net costs of retaining existing plants can in fact exceed the costs of new plants.⁷⁰

Another reason that regulators and generation developers sometimes promote discriminatory procurement practices is that they fear that market-based approaches will not be able to support competitive investments in new generating plants.⁷¹ These entities assert that new generation cannot be financed or built without a long-term PPA. We believe, however, that these fears are overstated in many cases and experience in merchant generation environments such as in Alberta's energy-only market and the recent market experience in PJM's capacity market provide important examples of how markets have attracted such merchant investments, as discussed further in III.A.3. Importantly, even if it were true that merchant generation investments are not feasible at reasonable prices in a particular market (*e.g.* due to excessive regulatory risk), this concern would not indicate that the only path forward is to rely on discriminatory procurement practices. System-wide costs could still be reduced by allowing existing generators to compete with new generators for short- and long-term contracts using non-discriminatory solicitations similar to those described in Section IV.

2. Ability to Attract Low-Cost Alternatives to New Generation

Evidence from the eastern capacity markets in PJM, ISO-NE, and NYISO shows that open, non-discriminatory procurement auctions are able to mobilize large quantities of low-cost capacity supply from unconventional and unanticipated sources. For example, when PJM's capacity market, the Reliability Pricing Model (RPM), was implemented in 2007, one of the primary drivers was a fear that the system was approaching capacity shortages in some locations and that a new forward approach was needed to attract new generation investments.⁷² After the initial focus on attracting new generation through PJM's forward capacity market, the surprise result after nine years of experience is that many other resources were attracted at prices below the cost of new generation.

Despite the fact that capacity prices were persistently below the cost of new generation, Figure 3 shows that RPM attracted 28,400 MW of additional installed capacity (ICAP) commitments, or

⁶⁹ Reported on an unforced capacity (UCAP) basis. See Pfeifenberger, *et al.* (2011b), Table 3.

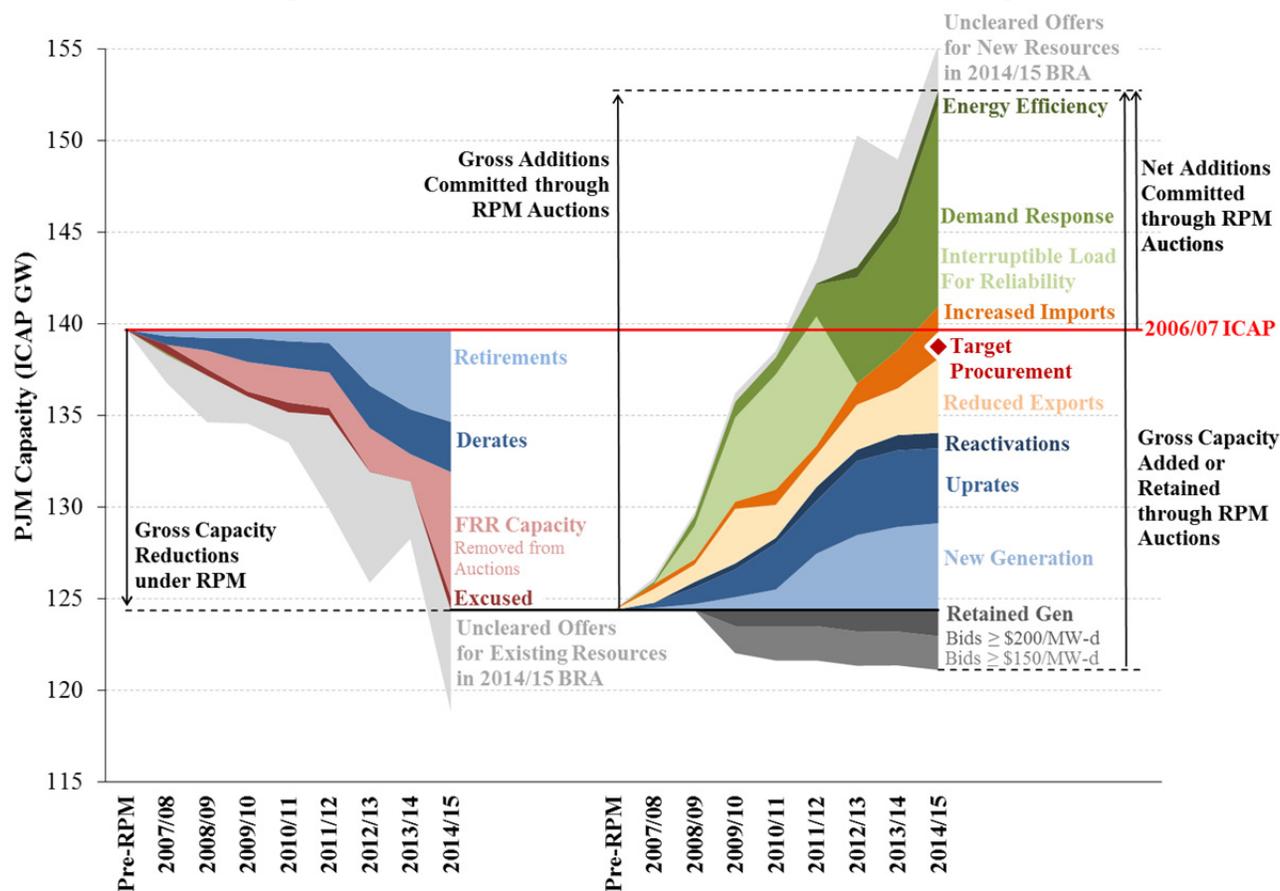
⁷⁰ For further discussion of equal compensation for old and new generation, see Pfeifenberger *et al.* (2011b).

⁷¹ For a discussion of the extent to which an absence of long-term procurement can undermine the financing of new power plants, see Pfeifenberger and Newell (2011c).

⁷² See PJM (2005), pp. 1-9.

13,100 MW of net commitments after considering retirements and other reductions in supply.⁷³ Reductions in capacity commitments are shown on the left side of the chart while new capacity commitments are shown on the right. While RPM did attract 4,800 MW of new generation, most new capacity additions came from lower-cost alternatives including: 11,800 MW of new DR and EE, 6,900 MW of increases in net imports, 4,100 MW of uprates to existing plants, and 800 MW of plant reactivations.⁷⁴

Figure 3
RTO Net Capacity Additions Committed in RPM Auctions through 2014/15



Sources and Notes:

All generation, DR, and EE values are cumulative totals reported in installed capacity (ICAP) terms. Figure excludes additions to Fixed Resource Requirement (FRR) capacity and PJM expansions. Gross and net changes represent Base and Incremental Auction commitments (offered but uncleared resources are in gray). See additional explanation and discussion in our review of RPM, Pfeifenberger, *et al.* (2011b), Section II.

⁷³ The chart shows capacities in gigawatts (GW), which are equal to 1,000 megawatts (MW).

⁷⁴ Note that Figure 3 excludes incremental resources committed in the most recent auction for the 2015/16 delivery year due to the timing of the underlying analysis. The gross incremental commitments from 2015/16 would be even greater than from other years, given that a large quantity of retirements resulted in PJM procuring a large quantity of new generation and some additional demand-side resources, as explained further in the following Section. See PJM (2012a), “2015/16 Base Residual Auction Report.”

Non-discriminatory procurement auctions create an opportunity for all types of capacity resources to monetize the value of their assets. The PJM experience shows that market participants have been able to identify lower-cost supply resources than the new generating plants that were anticipated. In particular, market participants did not expect the large quantity of demand-side resources and uprates to existing generation to become available at prices below the cost of new generation. The combination of attracting so many lower-cost alternatives to new generation through RPM and the economic downturn postponed the need for costly new generation investments by almost a decade, while capacity market prices were generally far below the cost of new entry.⁷⁵ Overall, this PJM experience strongly demonstrates the benefits of non-discriminatory procurement.

3. Ability to Attract Cost-Effective New Generation

In several markets, state regulators and some market participants favor supporting new generation through long-term PPAs based on concerns that a shorter-term, non-discriminatory market-based approach would not be able to attract new generation investments. However, several important examples demonstrate that the need for long-term contracts is often overstated.⁷⁶ A good example is Alberta's energy-only market, in which generation developers must make investments based purely on expected future energy and A/S market revenues. The market has no capacity payments, no regulated PPAs for new generation, and no long-term buyers (due to the retail choice environment). Despite this lack of revenue certainty, Alberta has attracted a steady stream of new generation investments over a decade of rapid load growth. In fact, since the market was instituted in 2000, Alberta has attracted more than 4,000 MW of new generation investments in a market with less than 12,000 MW total installed capacity.⁷⁷

Another important example of the ability of market-based mechanisms to attract new generation investments without long-term contracts comes from PJM's most recent capacity market auction for the 2015/16 delivery year. Prior to that auction, many state regulators and generation developers expressed concerns about RPM's ability to support merchant generation investments through its annual 3-year forward contracts, as noted above. Regulators in import-constrained eastern PJM states such as New Jersey and Maryland feared that their states would face a supply and reliability shortage if new generation were not developed, despite evidence from PJM and others showing that no such shortage existed through 2015.⁷⁸ Many market observers and participants surmise that the states were also motivated to engage in procurement limited to new generation by a desire to pursue price discrimination strategies as discussed previously.⁷⁹

⁷⁵ For a more comprehensive discussion and supporting documentation of PRM results and pricing, see Pfeifenberger, *et al.* (2011b), Section II.

⁷⁶ For a discussion of various concerns expressed by regulators, generation developers, and load interests, see Pfeifenberger and Newell (2011c).

⁷⁷ Over 2000-2010, Alberta attracted an average of 380 MW of generation additions annually (230 MW net annual additions after accounting for 150 MW annual retirements). Total system capacity increased from 9,400 MW in 2000 to 11,730 MW in 2010. See Pfeifenberger and Spees (2011a), Section IV.

⁷⁸ For example, see Pfeifenberger and Spees (2010).

⁷⁹ For example, the PJM Power Providers Group asserts that the "states have shown that they are ready, willing and able to exercise buyer market power," see Boshart (2011).

Some regulators and generation developers wishing to bring new projects online were also concerned about RPM's ability to provide sufficient revenue and revenue certainty to finance their projects.⁸⁰ These commenters claimed that RPM was not supporting new generation. They noted that most of the 4,800 MW of new generation that had been committed under the first eight years of RPM had been attracted by incentives for renewable generation or by cost-of-service-regulated rates.⁸¹

What these regulators and stakeholders failed to consider was that new generation investments were not needed at that time. As explained earlier, lower-cost resources attracted by RPM in combination with the economic downturn postponed the need for new generation investments for the better part of a decade. These alternative supplies kept market prices below the cost of new entry, with the result that new generation investments were simply uneconomic. Furthermore, although new generation did not clear, new generation was in fact attracted to offer into RPM capacity auctions. Our analysis of offered and cleared capacity over time shows that RPM attracted a substantial quantity of offers for new generation in every year and in almost every location. However, most of these new generation offers failed to clear the market only because low clearing prices made them uncompetitive compared to alternative sources of supply.⁸²

The quantity of low-cost alternatives to new generation is not unlimited. Eventually, once most of these low-cost resources had been developed within PJM, tightening reserve margins led to higher market prices that made new generation competitive. In the recent 2015/16 delivery year auction, RPM attracted more than 7,000 MW of new generation offers, and 4,800 MW of them cleared, as summarized in Figure 4.

As shown, a substantial portion of the cleared new generation came from investments with long-term contracts and regulated cost recovery, but the auction also cleared at least two major new merchant generation projects, the 291 MW Calpine Garrison Energy Center and the 620 MW LS Power West Deptford facility. These merchant combined-cycle plants cleared at a surprisingly low market price of only \$61/kW-year, which is 47% below PJM's administratively-calculated estimate of Net CONE.⁸³ Additional merchant generation projects were also offered, including the 832 MW First Lake CTs in the First Energy zone of PJM, but these projects were higher-cost than alternative supplies and therefore failed to clear.

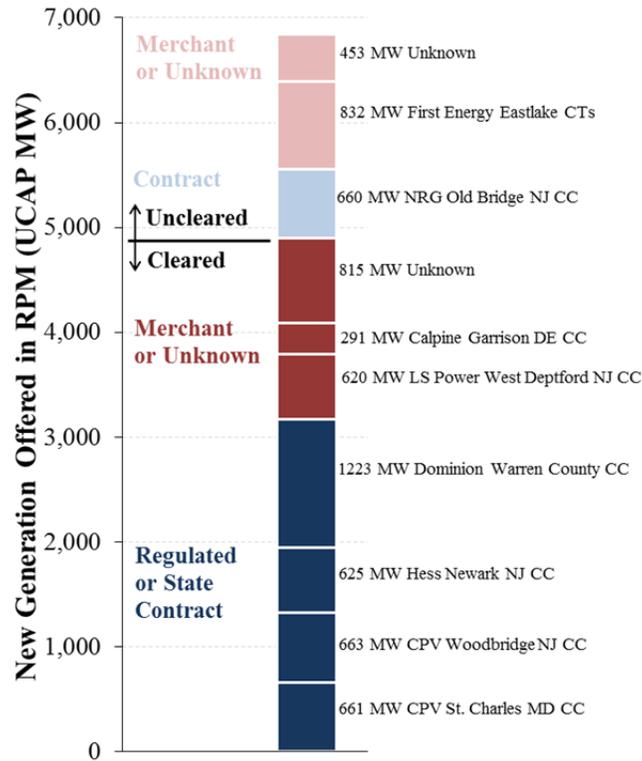
⁸⁰ For example, a draft of the NJ bill for these projects stated that “[t]he maximum three-year term [under RPM] is insufficient to support the project financing necessary to develop new, efficient generation within the state,” see Boshart (2011).

⁸¹ New generation quantities from Pfeifenberger, *et al.* (2011b), Section II.

⁸² See a detailed analysis in Pfeifenberger, *et al.* (2011b), Section II.

⁸³ Based on the EMAAC Net CONE estimate of \$115/kW-year from PJM's 2015/16 Planning Period Parameters, see PJM (2012a). Price converted to \$/kW-year from \$/MW-day.

Figure 4
New Generation Offered and Cleared in PJM 2015/16 Auction



Sources and Notes:

Cleared and uncleared quantities from PJM (2012a), “2015/16 Base Residual Auction Report.” Unit capacity ratings reported on approximate UCAP value; clearing status from SNL and Ventyx (2012).

B. FORWARD RESOURCE ADEQUACY REQUIREMENTS

Procuring on a multi-year forward basis assures that capacity prices and commitments are finalized at approximately the time when major irreversible investment decisions must be made for new power plants and major retrofits of existing power plants. This substantially increases the number of capacity resources that are able to participate and compete in the procurement process. It also provides forward visibility into available resources and retirements.

1. Advantages of Multi-year Forward Procurement

Locking in capacity payments and resource commitments on a forward basis provides a number of advantages relative to shorter-term mechanisms, as summarized in Table 2.⁸⁴ In particular, a non-discriminatory forward procurement process that locks in capacity commitments 3-4 years prior to delivery allows the market to rationalize supply and demand before significant irreversible financial commitments must be made, including commitments to proceed with environmental retrofits or initiating major construction activities at a new facility.

⁸⁴ Also see our more comprehensive discussion of forward capacity commitments in Newell, *et al* (2009); and Pfeifenberger, *et al.* (2009), Sections I, VIII, and IX.

Table 2
Pros and Cons of Forward Procurement Options

Forward Period	Advantages	Disadvantages
1 Month - MISO - NYISO - ISO-NE adjustment auctions - California final RAR supply plans	- Small uncertainty in load forecast - Market participant projections of monthly capacity will influence longer-term bilateral prices - No need for special accounting provisions for EE or PRD (already reflected in peak load forecasts) - Accommodates short lead-time resources such as DR - Accommodates short-term load migration under retail choice	- New supply cannot compete with existing - High capacity price volatility and risk of cycles of over- and under-supply, since there is no advance mechanism to rationalize supply with demand. - Large influence of administrative parameters, such as locational parameters and demand curves
1 Year - California initial RAR supply plans - PJM and ISO-NE incremental auctions	- Allows backstop procurement for deficient LSEs - Sufficiently forward to avoid many out-of-market reliability backstops - Some incremental supply can come online (DR, EE, mothballs, some uprates, retirement deferrals, advanced-stage construction)	- Insufficient time for many resources to come online (early-stage new construction, some retrofits, some uprates) - Need a mechanism to accommodate short-term load migration in retail access environment
3-4 Years - PJM - ISO-NE - Russia - Italy (proposed, with some procurement up to 10 years)	- Sufficient time to add (or postpone) substantial incremental supply, including new generation and major retrofits - Creates transparent forward view of market fundamentals - Increased ability to make rational retrofit vs. retire decisions, particularly in the face of environmental mandates - Helps stabilize prices and prevent boom-bust cycles - Approximately in line with timing of near-term transmission upgrades	- Greater load forecast uncertainty - Need to account for new EE and PRD (which takes several years before realized as reductions in observed peak loads)
5-10 Years - California LTPP - Utility and public power integrated planning processes	- Price certainty helpful for long lead-time resources and financing of new plants - Auction results provide increased transparency of forward market fundamentals, including additions and retirements - Far enough forward to integrate generation investments with traditional transmission planning	- High uncertainty in needed quantities imposes large risks on customers - Uncertainty in resource availability and ultimate costs increases risks to suppliers - Possibly excludes DR and aging generation - Possibly pre-empts longer-term bilateral contracting

Clearing in such a multi-year forward procurement process provides a potential investor with valuable information about future market conditions, helping them to decide whether they should bring their project online or postpone construction for another year.

There are also advantages to both shorter and longer forward periods. Shorter forward periods are associated with less uncertainty in load forecasts and other administrative parameters that can impose costs on customers if they prove to be incorrect. In particular, special accounting mechanisms may need to be developed to account for peak load reductions from energy efficiency and price-responsive demand (PRD) programs that are not treated as supply-side capacity resources, and that are not yet reflected in far-forward load forecasts. Shorter forward periods are more attractive to many DR suppliers, who stress that multi-year forward capacity commitments impose additional risks on them because their retail clients are unwilling to sign agreements that far in advance. Shorter forward periods are also attractive for some aging generators that are unsure how many years their asset will be able to operate without major capital reinvestments.

Forward periods exceeding 3-4 years also have some advantages. Far-forward generation planning can be more easily integrated with transmission planning which generally operates on a 5-10 year timeframe. Forward procurement of 5-10 years can also provide substantial revenue and planning certainty that helps new generation developers finance their plants, although providing this level of forward certainty also requires shifting more risk of uneconomic investments onto customers. Overall, we believe that a 3-4 year forward period provides a reasonable balance among these competing objectives and enables a healthy level of competition between new generation and shorter-term resources such as DR and existing generation.

2. PJM Forward Market Performance with MATS Regulation

One important advantage of a multi-year forward capacity procurement is that it facilitates cost-effective compliance with environmental mandates. This is particularly relevant in California given that many resources are facing a retire-or-retrofit decision in response to the once-through-cooling mandate.

PJM's 2014/15 auction results are a valuable case study demonstrating how a multi-year forward non-discriminatory procurement process can cost-effectively respond to large environmental mandates. The 2014/15 delivery year is the first year that will be affected by the Environmental Protection Agency's (EPA's) Mercury and Air Toxics Standards (MATS).⁸⁵ These standards impose strict limits on the emissions for mercury and other air toxics for coal and oil-fired power plants. Moreover, the mandate is unit-specific, meaning that every plant must either retire or comply with the standard by installing pollution controls.

Some coal plants can meet this mandate without substantial reinvestment costs, but a large number of plants are faced with large costs to install environmental retrofits such as Selective

⁸⁵ MATS will require compliance or retirement by April 2015, with a potential 1-year extension if the owner can demonstrate insufficient time to retrofit its resource. The compliance deadline is 60 days plus 3 years from the date of publication in the *Federal Register*, which was February 16, 2012. See *Federal Register* (2012), p. 9407.

Catalytic Reduction (SCR) or Flue Gas Desulfurization (FGD) if they continue operating. Considering the wide variation and uncertainty in plants' expected operating lives, compliance costs, and future energy and capacity revenues, many asset owners are faced with a difficult decision about whether to retire or reinvest. Uncertainties about what *other* plant owners might do with their power plants amplifies the difficulty of the investment decision as widespread retirements would increase market prices, thereby making additional retrofits economic. Currently, PJM anticipates more than 14,000 MW of generation retirements in response to environmental regulations.⁸⁶ This amounts to approximately 8% of PJM's entire generating fleet retiring, most of it within a single year.⁸⁷

PJM's forward capacity auctions for the 2014/15 and 2015/16 delivery years provided substantial transparency about the quantity of retirements to expect and assisted generation owners in determining whether their projects should be retrofitted. By allowing each supplier to offer in their units at levels reflecting their full going-forward costs (*i.e.*, including retrofits), the auctions sorted out the most cost-effective retrofit opportunities and provided these assets with a view of market conditions and additional revenue certainty they needed to move forward. The auction also required existing generators with retrofit decisions to compete against alternative sources of supply, such as demand response and new generating plants.

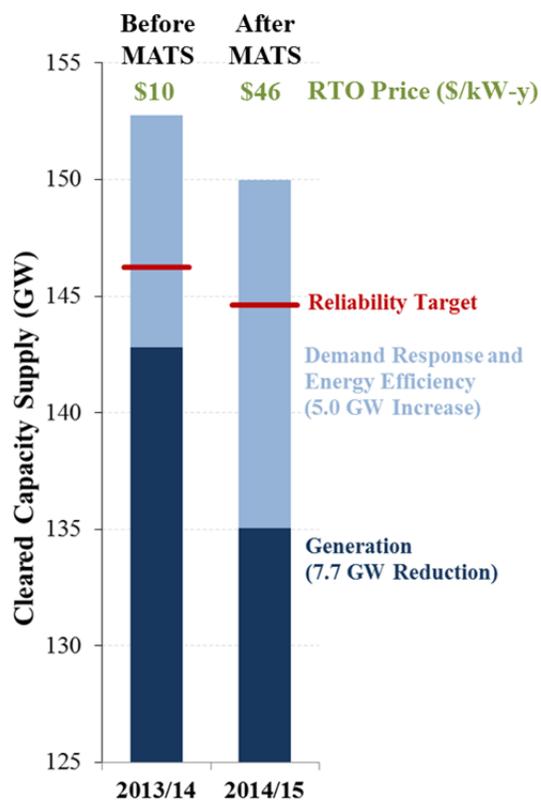
⁸⁶ Most of these retirements are driven by MATS, but others are driven by New Jersey's High Electric Demand Day (HEDD) regulation, both of which will come into effect near the end of the 2014/15 planning year. See PJM (2012a), "2015/16 RPM Base Residual Auction Results," p. 2.

⁸⁷ Based on 182,531 MW of existing generation supplies as of the 2015/16 delivery year, PJM (2012a), "RPM Resource Model."

Figure 5 summarizes the result of the PJM auction for the 2014/15 delivery compared to the auction results for the previous delivery year. It indicates that MATS regulations will induce a large quantity of simultaneous retirements, with cleared existing generation dropping by 7,700 MW between the two years. However, a large portion of this reduction in existing supply was offset by 5,000 MW of increased DR and EE commitments.

Much of the increase in demand resource commitments came from resources that had previously offered into the capacity market but failed to clear due to relatively low capacity prices. The retrofit or retirement decisions forced on many existing resources by environmental regulations changed the economic fundamentals for the 2014/15 delivery year, increasing capacity market prices from \$10/kW-year to \$46/kW-year and allowing more demand resources to clear at the higher prices. Importantly, reliability requirements were met (even exceeded) at market prices that remained substantially below the cost of new generation. Hence, the non-discriminatory forward procurement process yielded results that addressed environmental retirement challenges both adequately and efficiently.

Figure 5
PJM Cleared Capacity Before and After MATS



Sources and Notes:

See PJM (2012a), 2013/14 and 2014/15 Base Residual Auction Planning Period Parameters and Auction Results.

Quantities shown on an unforced capacity (UCAP) basis.

IV. IMPROVING CALIFORNIA’S RESOURCE ADEQUACY FRAMEWORK

In Table 3 and the remainder of this Section, we summarize several options for improving the efficiency of California’s resource adequacy framework, including: (A) reforming LTPP to incorporate non-discriminatory procurement processes; (B) increasing the efficiency of the RAR construct by implementing a residual capacity auction at the compliance deadline; (C.1) implementing both RAR capacity auctions and non-discriminatory LTPP procurements; or (C.2) replacing both RAR and LTPP with a forward capacity market.

Table 3
Options for Non-Discriminatory Capacity Procurement in California

Option and Description	Advantages	Disadvantages
<p>A. Reforming LTPP for Non-Discriminatory Capacity Procurement</p> <ul style="list-style-type: none"> - Revise RFOs to invite offers from existing generation, uprates, imports, DR, and EE - Procure only capacity (not energy or tolling) - Invite offers for shorter-term commitments 	<ul style="list-style-type: none"> - Reduces risk of administrative error in forecasting need (including replacing retirements) - Uniform capacity-only product reduces risk of administrative error in evaluating contracts of different types and durations - Able to identify and commit lower-cost alternatives to new generation 	<ul style="list-style-type: none"> - Difficult to accurately compare short- and long-term commitments (increases risk of uneconomic procurement) - Maintains inefficiencies such as lack of liquidity and price transparency, error in LTPP projections - IOU cost-recovery risk
<p>B. Increasing RAR Program Efficiency Through Centralized Auctions</p> <ul style="list-style-type: none"> - State agency, IOUs, or CAISO would procure all residual system and local capacity needs for RAR in a competitive auction (allowing for self-supply) - Costs allocated to LSEs (utilities, CCAs, ESPs, and participating Municipalities) - Replace current RAR compliance reporting as well as CAISO CPM backstop 	<ul style="list-style-type: none"> - Increase competition among all resources including existing and new gen, DR, EE, and imports - Increase price transparency - Reduce inefficiencies associated with current bilateral RAR market - Substantially reduce compliance reporting complexity and administration costs - Option for 3-4 year forward procurement would provide improved visibility and incentives - Introduce effective market monitoring and mitigation (not possible under bilateral RAR) 	<ul style="list-style-type: none"> - New state agency may have to be created - Implementation costs and risk of design flaws - Unless LTPP processes are also reformed, competition between new and existing resources will still be limited (associated price differentials and inefficiencies would persist) - Potential for greater reliance on RAR auctions could be a concern unless the capacity auctions are conducted on a forward basis
<p>C. Reforming both LTPP and RAR</p> <ol style="list-style-type: none"> 1. Introducing RAR Capacity Auctions and Non-Discriminatory LTPP Procurement 2. Replacing LTPP and RAR with an Integrated Forward Capacity Market 	<ul style="list-style-type: none"> - Combined advantages of reforming LTPP and RAR - Most efficient option for creating full competition among resource types on a level playing field 	<ul style="list-style-type: none"> - Implementation costs and risk of design flaws - Potentially greater reliance on RAR auctions could be a concern unless the capacity auctions are conducted on a forward basis - Implementation costs and risk of design flaws

A. REFORMING LTPP FOR NON-DISCRIMINATORY CAPACITY PROCUREMENT

As discussed in Section II.A.1, when the current LTPP process identifies a system need for new conventional generation, the utility will generally procure the new resources through a competitive RFO. To achieve a more efficient long-term procurement process, the scope of system RFOs would be revised to invite offers not just from new generation resources, but also from existing generation, imports, DR, and EE as long as these resources meet relevant qualification criteria.⁸⁸

Opening up RFOs for system-wide needs to other types of supply may result in less procurement from new generation resources and more procurement from existing generators. For this reason, the current “needs assessment” approach that stipulates what fraction of *new* resources will be procured will no longer be accurate. This indicates that the current needs assessment should be replaced with a portfolio procurement analysis. This analysis would determine a capacity procurement target for each forward year, without specifying what type of resources must supply that capacity. For example, the procurement target may be that 30% of total system capacity needs are secured seven years forward, 50% five years forward, and 90% three years forward.

Facilitating effective competition among different types of resources requires leveling the playing field to make sure that all types of supply resources are evaluated on the same basis. For this reason, RFOs would also need to be revised to procure only capacity, without a requirement or preference for bundled energy or tolling agreements. Current LTPP provisions regarding intermediate- and short-term contracting for *energy* on behalf of bundled customers could remain in place, except that energy procurements would be functionally separated from capacity procurements. Requiring that an energy contract be procured along with capacity substantially disadvantages or excludes some types of resources, such as DR. However, because the needs assessment behind the long-term RFO is ultimately driven by the need to meet California’s *capacity* needs rather than its *energy* needs, it would be inefficient to exclude resources such as DR and peaking plants that have substantial capacity value but little or no energy value.

Note that even if prospective suppliers in an RFO do not expect to win an energy contract, they will still consider the energy and ancillary service value of their asset when submitting their offers. For example, a new combined cycle plant will expect to earn substantial energy and ancillary service revenues even without an energy contract because the resource can additionally engage in bilateral energy contracts or simply offer into the CAISO markets. Such a seller will then be able to offer their resource into an RFO to sell capacity at their fixed costs minus their expected energy and ancillary service margins (*i.e.*, energy and ancillary service revenues net of operating costs). This levels the playing field among different types of technologies to determine which resources can meet system or local resource adequacy needs at the lowest net cost. For

⁸⁸ For example, import offers may be required to have firm import rights, new generation may be required to be sufficiently far along in permitting and development to come online in time, demand resources must explain how they will demonstrate verifiable peak load reductions, existing resources must not already have their capacity under commitment with another entity, *etc.* If an increase in the scope of the LTPP to achieve non-discriminatory capacity procurement for all resource needs is not feasible, the risk of over-procurement and market distortions should be reduced by limiting the scope of LTPP new resource procurements to the low end of the reasonable range of projected needs.

example, CCs have higher capital cost than CTs, but also have higher expected energy and ancillary service margins. For this reason, either type of technology could win an RFO, depending on the sellers' projections of market conditions.

Narrowing the RFOs to capacity-only procurement will substantially reduce the administrative complexity and risk of errors in the evaluation process. Current processes require complex evaluations that consider projections of net energy value for assets with very different capacity factors, meaning that selecting the most cost-effective resource requires the evaluator to accurately predict fuel, emissions, and energy market prices. The evaluator must also consider sometimes complex and uncertain factors such as transmission upgrades. With all the uncertainty inherent in these projections, it is very likely that the evaluator could select a resource that is ultimately more costly to consumers. The customer risk associated with such errors is substantially mitigated if the winning bid is selected only based on price for a well-defined capacity product, which could be either system-wide capacity or local capacity within a particular load pocket.⁸⁹ Intermittent renewables such as wind would also be invited to offer, but we would not expect these resources to be cost-competitive for capacity purposes unless they had already secured a long-term buyer for renewable energy credits (RECs).⁹⁰

Finally, we would recommend relaxing requirements for the forward period and duration of each contract term. Instead, these LTPP procurements would invite offers of any contract length from one-year to many years. Stipulating a contract duration of 10 or more years will implicitly exclude all DR and many existing generation resources, which would experience substantial risk of being unable to fulfill such far-forward commitments. Inviting offers for any contract duration would more effectively foster competition between short-term and long-term resources. While there is substantial difficulty in fairly evaluating a one-year contract against a 20-year contract, the evaluator could at least determine whether sufficient low-cost resources exist in the near term to postpone costlier long-term commitments with new generation resources.

B. INCREASING RAR PROGRAM EFFICIENCY THROUGH CENTRALIZED AUCTIONS

Separate from the LTPP process, there are a number of refinements that could be made to improve the efficiency and effectiveness of the RAR program. In particular, introducing non-discriminatory capacity auctions for any residual capacity needs at the time of the RAR compliance deadline would substantially increase the transparency and competitiveness of the process, thereby reducing the cost of meeting system and local reliability objectives. As we explain below, such auctions could be administered by a state agency, the IOUs, or the CAISO on a prompt or forward basis, and may incorporate a number of different design elements. We discuss here improvements that can be made to the RAR process independently of any revisions

⁸⁹ Note that the risks of inaccurate forecasts of market fundamentals are not eliminated, but most of them are shifted to suppliers who may be in a better position than utilities to manage and hedge against these risks.

⁹⁰ More generally, we recognize that California has a number of policy goals with respect to "preferred resources" such as renewables, energy efficiency, and demand response. We anticipate that some portion of the total resource adequacy needs would be met by continued procurement of these types of resources outside of utility RFOs for capacity. However, we also anticipate that clearing prices observed in non-discriminatory capacity auctions will provide better information with which to value the resource adequacy contribution of all resources, including preferred resources.

to LTPP, but note that substantial inefficiencies may remain unless both constructs are reformed as discussed in Section IV.C below.

1. Residual Capacity Auctions to Fulfill RAR Obligations

To widen the scope of competition and increase the efficiency of the RAR program, the state, the IOUs, or the CAISO could oversee capacity procurement auctions to fulfill system-wide and local RAR needs. Through a single, combined auction, this option would assure that 100% of all LSEs' local and system RAR needs would be met, possibly on a multi-year forward basis.⁹¹ System-wide demand for capacity would be represented by a vertical or sloped demand curve to procure projected peak load plus a 15% reserve margin, with local requirements met by imposing import limits or local minimum requirements in each load pocket. These local constraints would result in higher local prices when import constraints are binding, but local and system-wide prices would be identical when local capacity supply is sufficient. Similar constraints could be imposed to assure sufficient flexible resources are procured if the CPUC were to introduce such requirements into the RAR program.⁹² While procurement requirements for renewables could also theoretically be included into the auction, we do not see a compelling reason to add this complexity as current renewables procurement practices appear to be relatively efficient.⁹³ All suppliers qualified to sell capacity in California would be able to offer into this auction, including new and existing generation, uprate opportunities, imports, DR, and EE.⁹⁴

Resources already committed to supply capacity through self-supply or under bilateral contracts would be accounted for through one of two financially-equivalent approaches: (1) subtracting the capacity already procured from the required procurement quantity; or (2) requiring that the LSEs owning the rights to these resources offer them into the auctions, thereby creating offsetting buy and sell positions that are netted financially.⁹⁵ The costs of procuring capacity through this mechanism would be allocated to participating LSEs (including IOUs, CCAs, ESPs, and possibly municipalities) based on their share of customer loads, similarly to how non-bypassable charges

⁹¹ Note that if the auction is conducted by the state, then participation by non-CPUC jurisdictional municipalities within the CAISO may have to be voluntary while jurisdictional LSE participation could be mandatory.

⁹² See Section IV.B.5 for additional discussion of how flexible resource requirements could be incorporated into such an auction.

⁹³ Intermittent renewable resources, like all resources, would be eligible to sell capacity, but would usually have a relatively low capacity value. Renewable resources would incorporate potential capacity revenues into their investment decisions similarly to how they incorporate energy revenues. They may do so by selling bundled RECs, energy, and capacity to a long-term buyer under a fixed contract, which we would expect to be the most typical arrangement and would give the buyer the right to use that capacity as self-supply; alternately, as a less likely contracting approach, the renewable resource may sell only RECs to a long-term buyer while selling energy and capacity directly into the wholesale market.

⁹⁴ To mitigate potential market power concerns, a must-offer obligation may be need to be placed on all existing generation suppliers requiring them to offer at a level commensurate with their demonstrable net going-forward costs. Other suppliers such as new generation, uprates, DR, imports, and EE could have fewer or no restrictions on offer levels.

⁹⁵ Examples of both approaches already exist in other capacity markets, with the former being used in NYISO's capacity market and in MISO's proposed auction, and the latter used in PJM and ISO-NE.

are assessed through the current Capacity Allocation Mechanism (CAM).⁹⁶ Capacity costs could even be allocated after considering daily or monthly load migration among retail suppliers.⁹⁷

Note that because this auction would assure that all resource adequacy needs are met, it would replace the current supply plan process, and could be implemented in a way that substantially reduces administrative costs to the CPUC and market participants. For example, all capacity qualification accounting could be done on the supply side, similar to current processes for determining the capacity value of DR and generation resources. Once qualified, these resources could sell their capacity into the auction or bilaterally to individual LSEs as local or system “capacity credits” (discussed further in Section IV.B.5). Instead of having to submit complex annual and monthly supply plans identifying individual resources as they do now, LSEs would have a much simpler mechanism for demonstrating RAR compliance. LSEs could either: (1) procure no capacity on a bilateral basis, but simply have their capacity needs procured through the auction; or (2) procure a portion of their needs bilaterally, which would be represented as “capacity credits” in an online tracking platform similar to those used in other markets and automatically accounted for as self-supply in the capacity auctions.

The capacity auction would be for residual capacity procurement and, therefore, would likely cover only a small portion of the total system requirements if retail suppliers procure most of their needed capacity bilaterally prior to the auction date. For example, if the LTPP process remained largely unchanged, then utilities’ bilateral procurement quantities would be relatively high compared to total need and relatively little residual capacity would be procured through the CAISO auctions. This would result in a resource adequacy construct similar to that in MISO, where utilities, municipalities, and cooperatives procure the vast majority of their requirements through self-supply and bilateral contracting prior to and outside the ISO-administered Voluntary Capacity Auction (VCA).⁹⁸

Implementing an RAR auction for residual capacity without reforming LTPP would represent only a modest change relative to current practices, since the primary changes would be to: (1) replace current RAR supply plan reporting and CAISO backstop procurements with a simpler, more efficient mechanism for assuring that all system and local requirements are met; and (2) introduce a new residual auction as a supplement to the current bilateral capacity market for RAR.

Nevertheless, despite the fact that an auction would represent only a modest change, it would still offer a number of advantages, including: (a) increasing the level of competition among all resource types for supplying residual system and local RAR needs; (b) jointly procuring supply for all covered IOUs, CCAs, ESPs, and participating municipalities, assuring the most efficient price and clearing results; (c) increasing price transparency and access to the market for suppliers

⁹⁶ See CPUC (2007b).

⁹⁷ For example, see PJM’s approach that tracks customer migration on a daily basis, while the capacity costs of each customer are assessed based on annual Peak Load Contribution (PLC), see PJM (2012b), Sections 7.5, 7.6.

⁹⁸ On a MISO system-wide basis, only approximately 1% of total requirements are usually procured through the voluntary centralized auctions, although this fraction may increase once MISO implements its new resource adequacy construct in June 2013. See Newell, *et al.* (2010), pp. 23, 42, 44-45.

wishing to make incremental capacity investments, including for lower-cost uprates, DR, and imports; (d) reducing the need for out-of-market reliability backstops under CPM, especially if the auction is conducted on a forward basis; (e) increasing flexibility and reducing transactions costs for LSEs and suppliers making small adjustments to their capacity obligations, including at quantities not tied to the rating of any particular plant; (f) reducing the quantity of qualified capacity that may go unused due to bilateral contracting inefficiencies; (g) creating substantially improved transparency in pricing and supply availability, providing useful feedback into longer-term investment decisions made under LTPP processes; and (h) introducing the capability for effective market monitoring and mitigation to prevent the exercise of market power, which is much more difficult under the bilateral markets relevant for current LTPP and RAR programs.

Unless the LTPP process is also reformed as discussed in Sections IV.A and IV.C, many of the inefficiencies of the existing LTPP process would continue. These inefficiencies include the potential for over-procurement of new resources relative to relying on lower-cost investments in existing resources, and continuing to preclude efficient tradeoffs among different types of capacity resources as discussed previously.

2. State-Administered, IOU-administered, or CAISO-Administered Auctions

The system-wide RAR auction for residual capacity described in the previous section could be administered by either: (1) a state agency, making the auction subject to state jurisdiction; (2) on a joint basis or individually by the IOUs, also making the auction subject to state jurisdiction similar to current RFOs; or (3) the CAISO, potentially making the auction subject to FERC jurisdiction. If administered by a state agency or IOUs, CAISO would need to develop supplemental mechanisms to also cover the resource adequacy requirements of non-CPUC-jurisdictional entities.

If administered by a state agency, this agency's role could be similar to that of the Illinois Power Authority (IPA), which procures energy and capacity on behalf of standard offer customers in the state.⁹⁹ As a particularly relevant example for our purposes, one of the procurement auctions that the IPA conducts is for capacity commitments on behalf of customers within the MISO portion of the state (*i.e.*, Ameren's service area).¹⁰⁰ The capacity credits associated with that purchase can then be used toward meeting their resource adequacy obligations under MISO's resource adequacy construct. A disadvantage of introducing such a state-administered auction in California is that it may require the creation of a new state agency. A nearly identical approach would have the IOUs administer the capacity auction individually or on a joint basis, with procurement costs assessed to LSEs on a non-bypassable basis. One disadvantage of having IOUs administer such an auction, however, is that it could expose them to cost-recovery risks.

A RAR auction for residual capacity administered by CAISO would be very similar to one administered by a state agency or the IOUs. However, the CAISO auction would have the

⁹⁹ Similarly, Maine's electricity retail access rules require the Maine Public Utilities Commission to ensure that standard offer service for electricity supply is available to all customers in Maine. Under these rules, the Commission (not the LSE) is responsible for soliciting standard offer service from licensed competitive electricity providers through a competitive bid process. See MPUC (2012).

¹⁰⁰ See IPA (2012).

advantage that it would also include LSEs that are members of CAISO but not under CPUC jurisdiction.¹⁰¹ Having CAISO administer the auction would also avoid the creation of a new state agency and potentially allow leveraging existing infrastructure for tracking capacity commitments. Finally, although a CAISO-administered capacity auction would likely fall under FERC jurisdiction, the vast majority of resource investment decisions (likely including all new generation investments) would continue to be made through LTPP under CPUC jurisdiction and oversight.

3. Prompt vs. Forward Auctions

Residual capacity auctions to meet RAR requirements could be held in October preceding the delivery year, consistent with the current deadline for capacity supply plans, or it could be held on a forward basis. However, as discussed in Section III.B above, capacity auctions combined with a 3-4 year forward RAR requirement would provide a number of additional advantages, including providing suppliers with appropriate signals about whether their assets will be needed at approximately the time when major irreversible investment decisions need to be made.

These advantages make forward RAR requirement and residual capacity auctions attractive, although we note that the increased forward period would likely also require some revisions to the LTPP processes. Long-term RFOs for system needs could remain unchanged as long as they are conducted prior to the capacity auction. However, intermediate- and short-term RFOs for bundled customers would need to be revised as any bilateral contracts for capacity would be procured only prior to the forward capacity auction (but not after), while energy procurements could continue at any forward period (before or after the capacity auction).

4. Single-Year vs. Multi-Year Commitments

If a forward RAR auction is implemented it will require that all capacity commitments are procured, for example, three years prior to delivery. However, competitive retailers and regulated utilities might still procure a portion of their capacity needs on a farther-forward basis under multi-year commitments. Generally, we believe that LSEs exposed to competitive forces will be in the best position to determine what portion of capacity needs should be procured under a portfolio of self-supply and bilateral contracting positions. For this reason, we believe that most markets will be able to operate efficiently without additional requirements for multi-year or farther-forward capacity commitments.

However, if mandatory long-term contracting or enabling voluntary multi-year contracting were deemed desirable, there are a number of options for implementing multi-year commitments through centralized auctions. Some of the most efficient of these options include:

Voluntary Far-Forward or Multi-Year Auctions – Some LSEs and suppliers may wish to engage in additional multi-year or longer-term contracting, but may experience some disincentive against doing so due to the complexity, transaction costs, lumpy contract availability, or counterparty risk involved in traditional bilateral contracting. Introducing voluntary auctions for longer-term or multi-year capacity commitments would reduce

¹⁰¹ A state agency auction could also include demand from these entities, but likely only on a voluntary basis.

some of these impediments and facilitate longer-term contracting. However, it may be that relatively few buyers would voluntarily engage in long-term procurements, particularly if LSEs are subject to the risk of losing customers under retail choice. Even if no volumes cleared in these auctions, posting bid-ask spreads available from these auctions would provide market participants additional forward price visibility.

Carve-Out for Staggered Multi-Year Commitments – A mandatory longer-term procurement option could require that a certain portion of capacity be procured through staggered multi-year commitments. For example, 25% of capacity could be required to be procured under rolling five-year commitments with 5% procured each year.¹⁰² The multi-year auctions would be held each year prior to the residual RAR or forward capacity auction in which all remaining capacity needs would be procured under one-year commitments. As long as both auctions are non-discriminatory, suppliers would be able to efficiently offer multi-year commitments after considering expected prices in the residual auction and the risk differential between supplying under single-year and multi-year commitments. However, if this option is implemented such that a large proportion of procurement is based on very long-term contracts, it could inefficiently exclude lower-cost, shorter-term resources such as DR, upgrades to existing generating plants, and retirement deferrals.

Short- and Long-Term Offers in a Single Auction – Another option would be to specify different procurement targets as a function of forward period and procure that portfolio in a single auction for both annual and multi-year commitments. For example, the auction might seek to procure 5% of capacity needs on a ten-year forward basis, 50% on a five-year forward basis, and 100% on a three-year forward basis. Suppliers would be allowed to offer their assets into the auction under any desired combination of single-year or multi-year contracts.¹⁰³ The mechanics of administering and clearing such an auction would be quite complex, but could draw upon approaches used in other multi-product auctions for wireless spectrum, transmission rights, and PJM's capacity auction with multiple DR products.¹⁰⁴ The result of the auction would be a different capacity price for each delivery year (but not for each commitment term), with a quantity as stipulated under the procurement target, and with each supplier earning revenues equal to or greater than their offer price.

¹⁰² Note that if 5% of capacity were procured under five-year commitments every year, then a total of 10% would be under a multi-year commitment by the second year, 15% by the third year, and so on. In the sixth procurement year, the first set of five-year commitments would have ended and be replaced by the new procurement. Overall, this would result in 25% procurement under multi-year commitments in steady state.

¹⁰³ For example, individual assets could be offered as a series of 10 single-year commitments or one multi-year commitment. The asset owner would also identify these as contingent bids in that if some of the single-year commitments clear, then the multi-year commitment could not also clear.

¹⁰⁴ Selecting the lowest-cost combination of contracts would also require the auction administrator to apply discount factor reflecting the time value of money to customers. This introduces an opportunity for administrative error similar to what would be experienced under LTPP procurements that also invited single-year and multi-year capacity offers.

All of these options have the advantage that they are based on non-discriminatory procurement practices. However, only the first option efficiently allows LSEs to determine the optimal portfolio of short and long-term contracts and self-supply based on their risk mitigation preferences and retail customer commitments. The second and third options rely on administratively stipulated procurement portfolios that may be less likely to reflect LSEs' and customers' risk mitigation preferences. In fact, depending on the type of retail choice environment, the efficient proportion of long-term contracts may be relatively small, reflecting retail customers' unwillingness to make multi-year commitments. If pursuing one of these options, we would recommend against imposing a large proportion of long-term contracts, which likely would inefficiently shift investment risks from suppliers to customers.

5. Other Capacity Auction Design Options

If a residual capacity auction were implemented as described in Section IV.B.1 above, a number of decisions would need to be made to address individual design elements. The most important of these design elements include:

Demand Curve – Demand for capacity could be represented most simply as a vertical demand curve at peak load plus 15% and local minimums similarly determined at a fixed quantity. The demand curve would also reflect a price cap at some multiple of CONE or Net CONE.¹⁰⁵ However, sloping demand curves for system-wide and local resource adequacy needs could also be introduced to achieve a number of benefits, including: (a) reduced price volatility; (b) reduced ability of market participants to profitably exercise market power; (c) acknowledging the inherent uncertainty in determining the needed quantity given load forecast error and other administrative uncertainties; and (d) an improved ability to represent the incremental, declining value of capacity at higher reserve margins and the increased (but not infinite) value of capacity when procurement levels fall below the target.¹⁰⁶

Buy Bids for Non-Jurisdictional LSEs – Under a state-administered auction, the efficiency benefits could be extended to LSEs that are not under CPUC jurisdiction by allowing these entities to offer system or local area buy bids on a voluntary basis. These buy bids could be submitted at any price and would be added to the administrative demand curve applicable for jurisdictional LSEs. Any capacity procured by non-jurisdictional LSEs could be used toward meeting their supply plan obligations.

Monthly, Seasonal, or Annual – The capacity auction would be set up to procure the capacity product imposed by the RAR mechanism, which is currently a monthly product. Such an auction would result in different price and quantity results for each month.¹⁰⁷

¹⁰⁵ For a discussion of considerations when determining an appropriate price cap, see Pfeifenberger, *et al.* (2011b), Section V.

¹⁰⁶ We and others have conducted a number of theoretical and empirical studies of the advantages of various demand curve shapes. For example, see Pfeifenberger, *et al.* (2011b), Section V; (2009), Section VII.B.

¹⁰⁷ One likely result of a centralized or bilateral market for capacity based on such monthly commitments is that substantial capacity prices are only likely to be realized during the month or months of greatest scarcity, making most of these monthly obligations largely irrelevant. Further, most investment decisions associated with creating incremental capacity supplies must be made based on an annual or multi-year basis, with only moderate opportunities for month-to-month adjustments. For these reasons, the granular

However, because California has a relatively predictable pattern of experiencing the greatest scarcity during summer peaking conditions, it may be beneficial to simplify the RAR construct and associated auctions by either: (1) imposing an annual capacity requirement based on summer peak load, resulting in year-long capacity commitments and a single annual capacity price; or (2) relying on 2-season or 4-season requirements, to the extent that annual capacity commitments might preclude certain valuable off-system seasonal capacity sharing opportunities.

Reconfiguration Auctions for Shorter-Term Adjustments – If implementing a forward capacity auction, it will also be important to implement reconfiguration auctions to address changes in supply and demand conditions realized between the initial auction and the delivery period. As is done in PJM and ISO-NE, shorter-term reconfiguration auctions can be used to allow: (a) market participants to buy out of a capacity obligation (e.g., in response to an unexpected construction delay) by paying another supplier to fulfill that obligation; and (b) administrative adjustments in response to unexpected changes in load forecast or transmission import capability into a particular location.

Flexible Resource Requirements – If the CPUC and CAISO converge on a revised approach to flexible resource requirements, then this requirement could also be met within a single, co-optimized multi-product auction for capacity and flexibility characteristics. Flexibility requirements would be expressed as a minimum quantity of local or system-wide capacity with the flexibility characteristic required, e.g. for system-wide regulation capability.¹⁰⁸ Each supply resource would contribute a certain quantity toward the system RAR requirement as well as a different, lower quantity toward the flexible resource requirement. If there were a shortage of flexible resources in the system, resources providing this capability would earn a higher payment for the portion of the resource that can provide this needed flexibility characteristic. This added complexity would not change the overall auction-clearing approach of minimizing total procurement costs subject to the imposed constraints.¹⁰⁹

Capacity Credits to Enable Bilateral Markets – The bilateral market for capacity before and after any centralized auctions could also be enabled by the introduction of standardized “capacity credits” representing a specific quantity of supply qualified for system or local RAR. Similar to the Planning Resource Credits (PRCs) used in MISO, capacity credits would be created by suppliers that are take on a capacity obligation and could then be sold on the bilateral market to any LSE needing to meet its RAR obligation (or other

single-month commitment period approach introduces substantial complexity into the construct without providing substantial incremental value above a seasonal or annual commitment period.

¹⁰⁸ There may also be multiple types of flexibility required that could be expressed through different minimum quantities. For example, a CAISO proposal included a regulation requirement among other types of flexibility requirements. See CAISO (2012e), Section 5.

¹⁰⁹ The constraints imposed in this case would include: (1) a system-wide RAR requirement; (2) locational minimum RAR requirements; and (3) minimum requirements for regulation capability, ramp capability, etc. The auction design would also have to consider the differential contributions that each resource would make toward meeting each of the three types of requirements, e.g., an individual resource may contribute 100 MW toward system-wide RAR, 100 MW toward a local RAR, no regulation, and 10 MW of ramping capability.

suppliers wishing to buy out of a previous capacity commitment).¹¹⁰ Introducing these tradable capacity credits and supporting them with an online tracking mechanism would reduce bilateral market transactions costs and counterparty risk in California. If further supported by an over-the-counter trading platform (similar to those available for many other commodities such as fuels), the market would also benefit from enhanced liquidity and forward price visibility.

Interaction with Energy and A/S Markets – For a capacity market or forward flexibility market to function most efficiently, it is imperative that the forward market be designed to interact with efficient energy and A/S markets. We stress two important factors to consider in this respect. First, demand resources incorporated into the capacity market should have the opportunity and incentive to participate in setting prices in the energy and A/S markets, particularly during super-peak conditions when they may be called as emergency reserves. Second, forward flexibility requirements should be defined consistent with A/S products sold in real time. This will yield more efficient energy and ancillary service prices that improve performance and investment incentives, thereby also reducing the market prices for forward resource adequacy and flexibility commitments.

While each of these options has important implications for overall market structure and performance, a centralized capacity auction would provide substantial efficiency benefits regardless of which exact implementation mechanisms are adopted.

C. REFORMING BOTH LTPP AND RAR

The previous sections discussed the improvements that could be made to increase the efficiency of LTPP and RAR programs individually. However, it would be best to increase the overall efficiency of California's resource adequacy construct by addressing inefficiencies in both constructs. This could be achieved by either: (1) implementing the efficiency improvements to LTPP and RAR simultaneously; or (2) replacing both constructs with an integrated forward capacity market.

1. RAR Capacity Auctions with Non-Discriminatory LTPP Procurement

As discussed in the previous Sections, efficiency improvements could be made independently to RAR and LTPP, but improving both constructs simultaneously would provide even greater overall efficiency improvements. For example, if capacity auctions were introduced to meet RAR obligations while the LTPP process remained unaltered, all of the inefficiencies associated with current LTPP processes would persist. The LTPP procurement process would still be unable to facilitate efficient tradeoffs between new and existing resources, potentially leading to continued over-procurement of high-cost new resources when lower-cost alternatives exist.

Similarly, if LTPP were reformed without introducing improvements to the RAR program, then short-term inefficiencies associated with the bilateral RAR construct would persist. In particular, failing to implement a residual capacity auction for RAR would forgo efficient tradeoffs among DR resources, uprates, imports, and other resources available on a short-term basis.

¹¹⁰ See Newell, *et al.* (2010), Sections III.C and IV.A.2.

Reforming both constructs at the same time would achieve all of the benefits we have described in the earlier sections. We also note that, while the RAR capacity auction would still be a residual auction to procure system and local RAR needs not already met through self-supply and bilateral contracting, its efficiency and attractiveness to market participants may make it a relatively more important part of California's resource adequacy construct over time. In particular, volumes cleared under the RAR auction would increase if the quantity of capacity procured for system and bundled customers under LTPP were decreased. Further, non-discriminatory capacity procurements under LTPP would tend to equalize prices under RAR and LTPP (after adjusting for the risk and uncertainty implications of the different forward periods).

Given the greater importance that the RAR capacity auction would likely gain in assuring resource adequacy if LTPP were also reformed, it would also be important to consider conducting the auction on a multi-year forward basis. The CPUC and CAISO appear that they may be unwilling to tolerate the occasional price spikes and supply shortages that could materialize in a short-term market (particularly in light of the upcoming once-through cooling and flexibility challenges). Implementing the RAR obligation and residual capacity auction on a 3- to 4-year forward basis would better enable competition between new and existing resources while attracting sufficient commitments to assure that system reliability needs are met as discussed in Section III.B above.

2. Replacing LTPP and RAR with an Integrated Forward Capacity Market

Reforming LTPP and RAR as described in the previous section would achieve the vast majority of the benefits of non-discriminatory and forward procurement described in Section III. However, replacing both constructs with an integrated forward capacity market could achieve some additional incremental benefits. Most importantly, a single, integrated forward capacity market will fully level the playing field among all capacity resources by assuring that all suppliers are providing exactly the same product at the same time (*e.g.*, a one-year capacity commitment on a 3-4 year forward basis). This would substantially reduce the risks that customers bear due to difficulty in accurately comparing the value of, for example, offers for one-year vs. ten-year capacity commitments under LTPP.

Implementing a forward capacity auction for all system and local requirements would also reduce the risks that customers bear from the potential for sub-optimal capacity portfolio procurement targets under LTPP. While portfolio procurement targets under LTPP may be informed by substantial analysis regarding the need for and availability of short- vs. long-term capacity commitments, there are large uncertainties underlying these analyses that will necessarily lead to some uneconomic procurement. For example, relying too heavily on long-term contracts may result in inefficient under-procurement of short-term resources such as DR. In contrast, procuring all capacity resources under a forward capacity market would shift more of these risks onto suppliers, who have the best information about their resources' costs and availability.

V. RECOMMENDATIONS

California could gain substantial efficiency benefits by reforming the current LTPP and RAR programs in two important ways. First, the programs could be refined to incorporate non-discriminatory procurement practices that invite competition among all types of capacity resources including: (a) new generation; (b) existing generation, including resources with low going-forward costs, as well as those that need major reinvestments or retrofits to continue operating; (c) investments to uprate existing generation facilities; (d) imports; and (e) demand-side resources including DR and energy efficiency. Unless each of these types of resources has the opportunity to compete to supply capacity at the same price and under the same terms, it will not be possible to meet resource adequacy objectives using the lowest-cost mix of supply resources, as we explain in Section III.A. Second, California may gain additional efficiency benefits by procuring all of its needed capacity commitments on a 3-4 year forward basis, as explained in Section III.B. Meeting the local and system RAR objectives on a forward basis will increase the scope of competition by awarding capacity commitments at approximately the same time that suppliers need to make major irreversible investment decisions for retrofits and new construction.

To improve procurement efficiency and achieve these benefits, we recommend either: (1) reforming RAR and LTPP to incorporate non-discriminatory procurement practices; or (2) replacing both mechanisms with a forward capacity market. Further, the CPUC and CAISO appear to require assurance of resource adequacy on a forward-looking basis, particularly in light of upcoming once-through-cooling and flexibility challenges. Considering these concerns, the efficiency of either approach could be improved by including 3-4 year forward obligations covering all or most system and local capacity requirements, including requirements for operationally flexible capacity. Ideally these forward obligations would be met through non-discriminatory, transparent, single-price auctions conducted by CAISO, a state agency, or the IOUs. If administered by a state agency or IOUs, CAISO would need to develop supplemental mechanisms to also cover the resource adequacy requirements of non-CPUC-jurisdictional entities.

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LIST OF ACRONYMS

A/S	Ancillary Service
CAISO	California Independent System Operator
CC	Combined Cycle
CCA	Community Choice Aggregator
CEC	California Energy Commission
CO ₂	Carbon Dioxide
CO ₂ e	Carbon Dioxide Equivalent
CONE	Cost of New Entry
CPM	Capacity Procurement Mechanism
CPUC	California Public Utilities Commission
CPV	Competitive Power Ventures
CSP	Curtailed Service Provider
CT	Combustion Turbine
DR	Demand Response
E&A/S	Energy and Ancillary Service
EE	Energy Efficiency
EMAAC	Eastern Mid-Atlantic Area Council
EPA	Environmental Protection Agency
ESP	Electric Service Provider
FERC	Federal Energy Regulatory Commission
FGD	Flue Gas Desulfurization
FRR	Fixed Resource Requirement
GW	Gigawatt
HEDD	High Electric Demand Day
ICAP	Installed Capacity
IPA	Illinois Power Authority
ISO	Independent System Operator
ISO-NE	Independent System Operator New England
IOU	Investor Owned Utility
kW	Kilowatt
kW-y	Kilowatt Year

LADWP	Los Angeles Department of Water and Power
LCR	Local Capacity Requirement
LDA	Locational Deliverability Area
LSE	Load Serving Entity
LTPP	Long Term Procurement Plan
MATS	Mercury and Air Toxics Standards
MISO	Midwest Independent System Operator
MOPR	Minimum Offer Price Rule
MPUC	Maine Public Utility Commission
MW	Megawatt
NYISO	New York Independent System Operator
PG&E	Pacific Gas & Electric Company
PPA	Power Purchase Agreement
PRC	Planning Resource Credit
PRD	Price-Responsive Demand
PSEG	Public Service Enterprise Group
RAR	Resource Adequacy Requirement
RFO	Request for Offer
RMR	Reliability Must Run
RPM	Reliability Pricing Model
RPS	Renewable Portfolio Standard
SCR	Selective Catalytic Reduction
SMUD	Sacramento Municipal Utility District
SWRCB	State Water Resources Control Board
UCAP	Unforced Capacity
VCA	Voluntary Capacity Auction