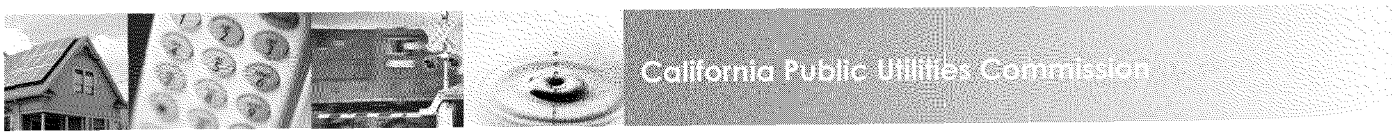

Briefing Paper:
A Review of Current Issues with Long-Term Resource Adequacy

ENERGY DIVISION
&
POLICY AND PLANNING DIVISION

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I. Introduction

In advance of a Long-Term Resource Adequacy Summit[1] on February 26, 2013, jointly sponsored by the California Public Utilities Commission (CPUC) and California Independent System Operator (CAISO), CPUC Staff have prepared this briefing paper which reviews current issues with the existing Resource Adequacy (RA) and Long Term Procurement Planning (LTPP) frameworks. These two proceedings[2] are the State's primary regulatory programs for addressing and overseeing electric reliability issues.

The intent of this paper is to provide background information on the topic of long-term resource adequacy in California, and to identify challenges and options around this issue. The purpose of the paper is not to make recommendations on next steps.

Over the last 10 years, California has had adequate reserves to maintain reliable grid operation under the CPUC's resource planning processes. However, California's electrical system is undergoing and planning for unprecedented changes, including the introduction of unprecedented levels of intermittent renewable energy, the retirement (and/or repowering) of over 16,000 MW of gas fired power plants that use once-thru-cooling (OTC) technology, and an increasing proportion of California's generation fleet that is expected to go beyond its design life in the coming years.

These fundamental changes to the electric system present challenges to future electric system reliability. This paper sets out to describe the reliability concerns inherent in this transition of our electric system toward increased renewable generation, away from OTC and other aging generation.

This paper highlights four key challenges:

- ***Oversupply of System Capacity***: A large oversupply of generic system capacity exists, although some local areas may need new local capacity to meet reliability needs.
- ***Insufficient Revenue and Certainty for Generators***: The existing RA and LTPP policy frameworks are criticized for not always sending sufficient, timely and accurate signals to generators to invest in new power plants, plant upgrades, or maintenance of existing generators.
- ***Need for Certainty around Flexible Resource Needs and Flexibility Definition:*** There may be insufficient flexible capacity in future years. The resource modeling for future flexible capacity needs, particularly in light of the large quantity of renewable resources expected in the future, is ongoing. The definition of what resources should be labeled flexible is uncertain.
- ***Insufficient Certainty on the Future Quantity of Capacity available for Reliability:*** The looming possibility that existing capacity resources (including

[1] Information on Long-Term Resource Adequacy Summit, February 26, 2013: http://www.caiso.com/informed/Pages/MeetingsEvents/PublicForums/Long-TermRASummit.aspx

[2] Current RA Proceeding: Rulemaking (R.) 11-10-023 and current LTPP Proceeding: R.12-03-014.

relatively new and efficient ones) without long term contracts will not be available to the system in the future.

While the CPUC's RA and LTPP programs are focused sharply on addressing these changes, some parties believe that different or faster programmatic changes to the regulatory framework are required.

II. Background

This section provides background on the CPUC's primary programs related to procurement and resource adequacy: RA and LTPP, as well as the CAISO's role in backstop procurement activities. See Appendix A for more background information on California energy, capacity, and ancillary service markets.

A. Capacity Obligations and CPUC's Resource Adequacy (RA) Program

Resources that are available to produce electricity are called capacity. A capacity shortfall occurs when there is more electricity demanded from customers than can be provided by the available capacity resources. To avoid capacity shortfalls that can cause blackouts, system planners generally plan the electrical system to have a comfortable planning reserve margin. The CPUC established that a planning reserve margin of 15-17 percent above the forecasted electrical capacity demand is an appropriate level of reserves to accommodate both variations in weather and various types of outages. The CPUC's reserve requirement means more capacity will be available than will be required to serve expected load, and thus some capacity resources do not receive substantial (or any) energy markets revenues. Sometimes this dynamic is referred to as resources with little or no "run" time. Resource owners generally structure their revenue sources (e.g. contracts) such that they receive a capacity payment to compensate them for the fixed costs of being available, in addition to energy market revenues, to compensate them for the variable costs of running in any particular hour of the year.

Existing RA Obligations

The CPUC's RA program annually establishes minimum capacity obligation requirements for CPUC jurisdictional load serving entities (LSEs) [3] on a one year-ahead basis at both the system and local level. The current RA program identifies the amount of capacity resources needed to maintain reliability and requires load serving entities to supply that amount of capacity resources to the CAISO energy markets. In order to

[3] Load serving entities provide retail power to customers. The State's three large privately owned utilities (PG&E, SCE, and SDG&E) are the largest load serving entities under CPUC's jurisdiction, but there are currently 14 electric service providers and one community choice aggregator that sell power independently of utilities. The CPUC does not regulate government owned electric utilities, such as Los Angeles Department of Water and Power (LADWP) or Sacramento Municipal Utilities District (SMUD).

identify the amount of capacity needed, the CPUC undertakes a process with cooperation of both the California Energy Commission (CEC) and the CAISO. The CEC forecasts the amount of load that is expected in a year and the CAISO forecasts the amount of resources that are needed system-wide and in local areas[4]. The CPUC considers both inputs, determines the appropriate level of reliability, and then orders load serving entities to procure capacity resource to that level. For system RA requirements, the CPUC uses a 15 percent planning margin. For local RA requirements, the CPUC considers a peak weather (1:10 year) and the loss of the two largest contingencies (generation or transmission). The forecasted need for system and local resources is split as RA procurement obligations among load-serving entities (LSEs) in proportion to their coincident share of utility service area annual peak demand.

LSEs are required to supply capacity resources to meet the forecast needs. The key RA obligation is that a resource counted as "RA capacity" must bid into the CAISO energy markets and be available to produce electricity when needed. Each day, the CAISO runs a day ahead integrated network model and dispatches resources efficiently to meet expected demand. All capacity designated as RA capacity can be scheduled to deliver energy by the CAISO if needed to maintain reliability. Each year, the RA program requires LSEs to submit year-ahead filings (due in October) and twelve month-ahead filings (due monthly) during the compliance year. The year-ahead filings show that load serving entities have procured capacity to meet 90 percent of the forecast system need (the system need equals the forecast plus the 15 percent reserve) during the five summer months (May-September) and 100 percent of the forecast local needs. The month-ahead filings require load serving entities to show 100 percent of system need (again the system need equals the forecast plus the 15 percent reserve). The CPUC staff and the CAISO staff evaluate annual and monthly filings to ensure adequate reserves.

The RA program has many detailed rules necessary to make the program function. Some of the more controversial rules include the methodologies for determining how much each resource contributes as capacity and how to count resources under construction but not yet in operation.

Current RA Proceeding Examining Flexibility Requirements

The current RA proceeding Rulemaking (R.) 11-10-023 is considering proposals to add a flexibility requirement to RA program. If adopted, LSEs would be required to procure, and report in their year-ahead and month–Ahead filings, specific amounts of capacity resources that are considered flexible. Energy Division has released a proposal to use a CAISO methodology for establishing the flexible RA capacity levels. The RA proceeding also needs to consider an approach for determining the counting conventions and other implementation requirements. The proceeding has scheduled a Proposed Decision by June 2013 with the expectation that the CPUC could establish flexible RA capacity procurement rules as early as the 2014 compliance year.

[4] A local area is an area where there is not sufficient transmission to supply all the area's power needs from outside the area, therefore some generation resources are needed inside the area to achieve the desired level of reliability.

The Energy Division's 2011 Annual RA report was released on February 5, 2013[5], and it provided a review of the CPUC's RA program, summarizing RA program experience during the 2011 RA compliance year. The report provides aggregate RA pricing information for over 450 RA contracts used in 2011 compliance.

B. Capacity Planning and CPUC's Biennial Long Term Procurement Plan (LTPP) Proceeding

The LTPP proceeding develops assumptions and forecasts of resource availability and determines if the existing plus planned mix of resources is sufficient to meet future needs. The CPUC has designed the LTPP proceeding to occur every two years and look at least ten years forward. In the current LTPP rulemaking, the LTPP is looking both 10 and 20 years forward.

The LTPP proceeding has three main functions: to determine if a sufficient amount of resources will be available in the future to meet reliability needs over the long-term; if insufficient resources are available, to authorize the procurement of new resources to meet the identified needs; and to examine, revise, and authorize the rules PG&E, SCE, and SDG&E must follow when procuring resources for bundled customers. The third function of the LTPP proceeding does not concern us here, we are focused on the first two functions related to reliability. In the current regulatory proceeding this particular function of the LTPP is referred to a "LTPP Track II".

Capacity Supply and Demand Forecasts in LTPP Process

The LTPP uses the demand forecast produced by the CEC in its Integrated Energy Policy Report (IEPR) process. The LTPP uses other forecast information developed largely in other CPUC proceedings, for example the goals and plans adopted in the energy efficiency, demand response, renewable resource procurement, and combined heat and power proceedings.

To accommodate a range of future scenarios, the forecasts are, at times, more conservative (i.e. expect fewer supply resources or higher demand) than those proposed and adopted in the CPUC's individual resource proceedings. One of the more controversial aspects of planning is deciding how conservative to make these planning forecasts. While resource programs often adopt ambitious goals to promote preferred resources, the LTPP's goals are to make realistic projections which can be used as the basis of reliability expenditures.

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[5] The Energy Division 2011 RA Report is available here: http://www.cpuc.ca.gov/PUC/energy/Procurement/RA/index.htm

LTPP Scenario Planning and Operational Modeling

The LTPP supply and demand forecasts are used for scenario planning and operational modeling. Because CPUC policy direction can greatly influence the mix of resources over a 10 or 20 year planning horizon, the LTPP examines different scenarios based on potential policy options. For example, the current LTPP has one scenario based on policies continuing with minor changes and a second scenario based on a major realignment of procurement toward distributed generation. See D. 12-12-010 for a full description of the scenarios and sensitivities being modeled in the 2012 LTPP.

The LTPP Track II operational modeling results will provide the CPUC with information on the differences in resource needs, if any, that would occur under each scenario. Based on this information, the CPUC may choose to authorize the utilities to procure new resources to meet any projected resource shortage. Since specific proceedings usually address the procurement targets for preferred resources (energy efficiency, demand response, renewables, etc.), the LTPP authorizations have traditionally been for new natural gas fueled resources, but in recent years the CPUC has been moving toward better integration to ensure preferred resources are procured first.[6]

Current LTPP Cycle Focuses on Capacity Needs in Context of Major System Changes

The focus of the current LTPP cycle is driven by a need to consider how the supply of electric capacity will be affected by the major transformational changes occurring in the electric industry. Finding the optimal mix of resources and resource capabilities is one of the major challenges in the LTPP. Some of the key transformational changes occurring in the next few years include:

- The retirement of generators using once-through-cooling (OTC) systems[7], which creates a need for some new capacity, particularly in certain local areas.
- The increased use of intermittent renewable generation (as a higher proportion of the overall resource mix) creates a need for increasing levels of flexible resources to ensure that the system remains in balance at all times.
- The increase in the proportion of California generation that is beyond its design life, or will be, during the planning period.

While a party to the LTPP, the CAISO has taken a lead role in modeling the need for flexibility under the scenarios adopted in the LTPP. It is hoped this analysis will provide information on the type and amount of different flexibility needs and how those needs vary under the different policies and circumstances embedded in the adopted scenarios and sensitivities.

[6] See the 2012 LTPP Track 1 Decision, D. 13-02-015, adopted February 13, 2013 for an example of a resource authorization that includes a suite of resources, beyond natural gas fueled resources.
[7] See Water Resources Control Board Statewide Policy on the Use of Coastal and Estuarine Waters for Power Plant Cooling, http://www.waterboards.ca.gov/water_issues/programs/ocean/cwa316/

Once the resource needs are identified, the CPUC will need to determine if the current resources are adequate to meet future needs, and if not, authorize the procurement of the optimal mix of new resources. A decision in this LTPP cycle is expected at the end of 2013, with a focus on the need for system and/or flexible resources.

Local Capacity Need Review

Although a future LTPP Track II decision could authorize new resource procurement as described above, the CPUC separately looks at the long-term resource needs in local areas. This review can occur before or after the completion of the Track II decision. In advance of the 2012 LTPP Track II decision, the CPUC has two near term procedural opportunities to review local needs in a few of the critical local areas. These near term opportunities are based on prior rounds of LTPP assumptions.

- The current LTPP, Track I determined the long term resource needs in the Los Angeles and the Big Creek-Ventura local areas.[8]
- The CPUC is currently considering San Diego Gas and Electric (SDG&E) Company's application[9] for new generation to meet resource needs in the San Diego local area.

C. CAISO Capacity and Flexibility Assessment

As detailed above, the CAISO plays a key role in both the CPUC's RA and LTPP programs. In addition, the CAISO has a number of tariff provisions (in place and proposed) that define its role in the review of the State's energy supply to ensure that there is sufficient capacity to meet energy demand.

Capacity Procurement Mechanism (CPM)

To ensure resources are available when needed, the CAISO plays a key role in reviewing capacity needs. Under CAISO's existing tariff, the CAISO has the Capacity Procurement Mechanism (CPM) a backstop procurement authority to procure capacity that is needed in the month-ahead or year-ahead time frame. The CPM tariff (Section 43.1.2) provides a backstop procurement mechanism for the CAISO for unexpected events not anticipated by the RA program or in the event that the RA program leaves a capacity deficiency. The CAISO's tariff allows for the CAISO to issue a "CPM designation" to a generation resource for a defined period of time (up to one year) for six specified reasons (a significant event, a capacity deficiency, a retiring resource, etc), and during that period of designation, the resource receives a capacity payment of $67.50 kW/month.[10]

[8] D. 13-02-015.

[9] Application (A.) 11-05-023.

[10] CAISO Tariff 43.1.2 quotes six reasons for a CPM designation: 1. Insufficient Local Capacity Area Resources in an annual or monthly Resource Adequacy Plan; 2. Collective deficiency in Local Capacity

Proposed Flexible Capacity and Local Reliability Resource Retention (FLRR) Mechanism

More recently in December 2012, CAISO filed a proposed tariff at the Federal Energy Regulatory Commission (FERC)[11] after a lengthy stakeholder process to create CAISO backstop authority to retain resources that area determined to be needed on a multiyear forward basis to help maintain resource adequacy for local or flexible capacity.[12] The proposed Flexible Capacity and Local Reliability Resource Retention (FLRR) tariff allows the CAISO to administratively backstop any generation resource needed for future reliability needs if the CAISO deems the existing resource is (a) at risk of retirement and (b) needed in the 5-year forward time frame to meet local or flexible capacity needs.

Under the proposed FLRR tariff, each spring the CAISO will undertake a stakeholder process to determine "system reliability requirements" and "local reliability requirements" for the next five years. To determine the requirements, the CAISO would consider the most recent CPUC standard planning assumptions used for the LTPP process—but expressly reserves the right to adjust and use its own assumptions for load forecast, energy efficiency, and demand response programs and to "perform additional studies as it deems necessary."[13]

Each fall the CAISO will consider any requests for FLRR designations. A resource seeking a FLRR designation must submit a notice to the CAISO and its Market Monitoring department by November 1 stating its intent to retire the resource before the end of the next calendar year. The CAISO will then determine if the resource is necessary (or if multiple resources are necessary) to meet the identified requirements for system flexibility or local reliability.

A resource receiving FLRR designation will receive a minimum revenue guarantee to cover the resource's annual going forward costs which includes, among other costs, interest on debt incurred prior to or during the FLRR designation year that could have been avoided by retiring the unit, as well as "major maintenance project costs" for projects initiated during the FLRR designation year. The term of the designation is for one year, and a resource may request designation for additional one year terms each year.

Area Resources; 3. Insufficient Resource Adequacy Resources in an LSE's annual or monthly Resource Adequacy Plan; 4. A CPM Significant Event; 5. A reliability or operational need for an Exceptional Dispatch CPM; and 6. Capacity at risk of retirement within the current RA Compliance Year that will be needed for reliability by the end of the calendar year following the current RA Compliance Year. CAISO Tariff 43.7.1 designates the monthly CPM capacity payment: On February 16, 2012, the fixed CPM Capacity price of $67.50/kW-year shall become effective and shall remain in effect for two (2) years. On February 16, 2014, the fixed CPM Capacity price shall increase by five (5) percent and the effective price shall be $70.88/kW-year, which shall remain in effect for two (2) years until February 16, 2016.

[11] ER13-550-000

[12] FLRR stakeholder process information: http://www.caiso.com/informed/Pages/StakeholderProcesses/FlexibleCapacityProcurement.aspx

[13] Attachment A to CAISO filing, FLRR Proposed Tariff Section 44.3.2(1).

The CPUC filed comments at FERC in late January opposing the immediate implementation of the proposed FLRR tariff for a variety of reasons cited in the filing.[14] The CPUC filing made the case that the CAISO proposed tariff comes at a time when the CPUC and CAISO are working together in a variety of forums – including the RA and LTPP proceedings – to ensure the State has sufficient capacity reserves in the short and long-term. Additionally, the CPUC staff filing argued the FLRR mechanism would preempt the CPUC's ongoing efforts to develop least-cost, market-based approaches to fulfilling capacity needs.

CAISO Flexible Ramping Product Proposal

The CAISO is developing a flexible ramping product (also called Flexiramp) through a stakeholder process.[15] The CAISO prepared its "Second Revised Draft Final Proposal" for the new product in October 2012. Once implemented, the CAISO Flexiramp product will be a new ancillary service that will provide energy market revenues to resources that fill operational flexibility needs.

The CAISO proposal creates a new ancillary service which would be a short term energy market for resource to increase or decrease production (ramp) in 5-minute increments. The proposal includes both a process for procuring Flexiramp (Day-Ahead and Real-Time, separately) and for allocating costs based on "causation" (deviations). The CAISO put the Flexiramp proposal on hold, temporarily, while the FERC Order 764 compliance initiative (15 minute scheduling, etc.) and other fundamental reforms get resolved. During the delay period, the CAISO energy markets are operated with a "Flexiramp" constraint within the integrated forward market algorithm that ensures sufficient flexible capacity reserves for real time ramping needs. While the Flexiramp constraint is sufficient under today's market conditions, the expectation is that the Flexiramp product will offer a better long-term solution to these issues.

The CPUC Staff have submitted comments in support of the development of the flexible ramping product during the stakeholder process. The interplay between a proposed CPUC RA obligation to procure flexible capacity (in the RA proceeding) and the proposed (but delayed) CAISO energy market reform to create a product that provides energy market revenues to flexible resources will be important to monitor and coordinate as the initiatives evolve.

[14] CPUC protest to the CAISO FLRR Proposed Tariff, filed at FERC, January 23, 2013, available http://elibrary.ferc.gov/idmws/common/opennat.asp?fileID=13159779
[15] http://www.caiso.com/informed/Pages/StakeholderProcesses/FlexibleRampingProduct.aspx

III. Challenges of the Current Market Framework

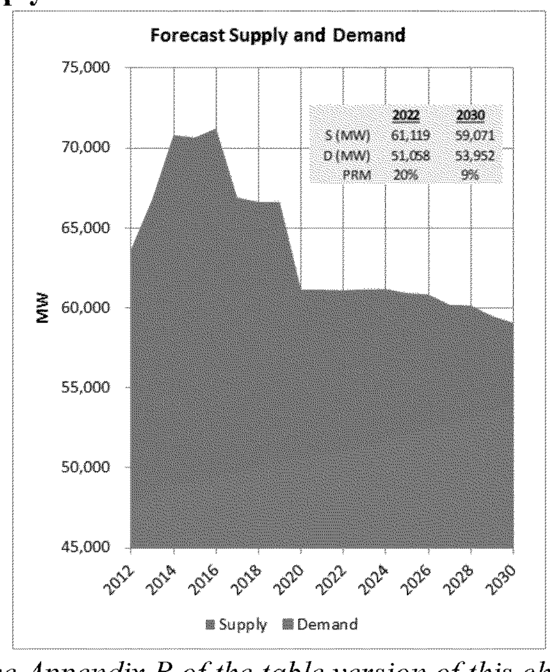
The following section frames in greater detail the four problems that are frequently cited as barriers to a healthy energy market system in California: A) the current oversupply of system capacity, B) insufficient revenue for generation owners, C) the desire for certainty around flexible resource needs and the definition of flexibility as a product, and D) the insufficient certainty on the quantity of capacity that will be available beyond one year-ahead RA showings.

A. Current Oversupply of System Capacity

Currently, the market has more capacity than is needed over the 10 year planning horizon; meanwhile the CPUC has authorized additional new supply and demand resources.

The most basic evidence of excess capacity is the load and resources balance analysis used in the LTPP's recent decision on LTPP planning assumptions from December 2012, see Chart 1 below. The table version of this chart appears in Appendix B. The planning margin for system-wide reserves peaks in 2014 at 44% and then is about 20% in 2022.[16] The planning margin for each of the state's transmission-constrained local areas is not considered in this chart, nor are additional resources authorized to meet local area needs.

Chart 1. Forecast Supply and Demand 2012-2030



Source: 2012 LTPP, See Appendix B of the table version of this chart. Data shown is the Base Scenario from D. 12-12-010, Appendix C, and page C-1.

[16] The CPUC has previously established that a 15-17% planning reserve margin is an appropriate level of reliability for system planning.

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The current LTPP Track II proceeding will review a variety of scenarios and consider the results of operational modeling of long term needs for both system, local, and flexibility needs. Although there is not expected to be a need for new system capacity, there may be a need for local capacity or flexible capacity in the planning horizon. Even unexpected major events do not significantly impact this oversupply of system capacity, for example, the outage of the San Onofre Nuclear Generating Station (SONGs) in Orange County, CA created a need for additional local resources in Orange County and Northern San Diego County, but it did not create a system capacity deficiency.

Table 1 shows the supply of system capacity in terms of the MWs of resources that qualify for RA. These resources are not necessarily procured as RA resources, but they are the list of RA eligible capacity qualified to serve the system. Table 1 shows that over the period of 2006-2011, the RA eligible capacity has increased from 46,687 MW to 51,895 MW.

Table 1. Resource Adequacy Eligible Capacity: Net Qualifying Capacity (NQC) for 2006-2011

Year	Total NQC (MW)	Total Number of Scheduling Resource IDs	Net NQC change (MW)	Net Gain in CAISO IDs on list
2006	46,687	563		
2007	46,504	572	(183)	9
2008	48,056	600	1,552	30
2009	48,899	613	843	13
2010	51,790	646	2,891	33
2011	51,895	649	105	3

Source: CPUC, 2011 Resource Adequacy Report, released February 5, 2013, page 15, NQC lists from 2006 through 2011[17]

California has significant excess system capacity for a number of reasons. First, since the 2006 LTPP, the CPUC has been authorizing the construction of new replacement generation – largely in order to replace retiring, mostly OTC, generation. At the same time only a limited amount of generation has actually retired. This situation persists, at least in part, because older generation, while less efficient than newer generation is still economically viable in the annual RA capacity markets. Older generation is well suited to meet the need of standby capacity, and it is usually less expensive to keep older generation available as capacity than build new generation. The OTC rules are expected to force retirement of ~13,000 MW of plants by the end of the decade, and Chart 1 takes that quantity of retirements into consideration.

Second, the renewable portfolio standard's (RPS) goal is to generate 33 percent of energy from renewable resources by 2020. The renewable resources built to meet the renewable portfolio standard also provide capacity in addition to producing energy. The RPS

[17] CPUC, 2010 Resource Adequacy Report, available at: http://www.cpuc.ca.gov/PUC/energy/Procurement/RA/

resources rarely supply capacity in locally constrained areas, further leading to excess system capacity. Similarly, the legislature has approved programs for additional supply resources – such as combined heat and power, biomass, and biogas resources. These additional resources will increase system capacity, but will not necessarily meet needs in locally constrained areas. Demand side resources (energy efficiency, demand response, customer-side distributed generation) that are not targeted to specific locally constrained/capacity deficient areas may also lead to excess system supply.

Third, forecast demand for energy and capacity has decreased over the last few years, largely due to the recent economic recession. Other significant factors contributing to a reduction in the demand forecast include energy efficiency impacts and impacts of customer-side distributed generation (in particular solar).

The current excess capacity may result in idling or retiring some resources that may be needed in a few years. For example, the CPUC adopted Resolution E-4471 in March 2012 to attempt to prevent Calpine's Sutter Energy Center from retiring due to a lack of capacity contract. The Sutter plant, a relatively new combined cycle plant built in 2001, essentially became uncompetitive in the State's various capacity markets. Calpine claims that if the CPUC had not intervened, the power plant would have pursued retirement in 2012; this scenario may repeat itself at some point in the next few years with Sutter or other resources since the underlying issues have not changed significantly.

B. Insufficient Revenue and Certainty for Generation Owners

Existing generation owners believe that the current market revenue stream is not sufficient to ensure that long term maintenance is performed, especially in the context of highly competitive RA markets and the absence of long-term contract opportunities for existing power plants.

All resource owners need to recover their costs, including the cost of capital, from the electricity markets. The main markets are energy, capacity, and ancillary services. See Appendix A for more background information on energy markets. Some resources owners believe that the current markets do not provide sufficient revenue to cover their long term costs. There has been testimony in proceedings that revenues have not been adequate to incent long term maintenance or to finance improvements that might make a resource more operationally valuable to the system.

The CPUC's RA and LTPP regulatory framework has the effect of creating two separate capacity markets[18]: one market for new generation that can result in contracts of 10 years or longer, and a different market focused on shorter term contracts of less than five years for existing generation. Once a generator is out of its initial long term contract, it has

[18] The markets referred to here are decentralized capacity markets. Utilities and other LSEs run "requests for offers" (RFOs) and/or have bilateral negotiations between buyers and sellers of capacity. There is no "centralized" capacity market in California.

little expectation of a future long-term contract. Generators can only expect to compete in near-term RA markets for existing generation.

Generators generally need to be under a long term contract to do initial construction financing, but usually do not have an opportunity for future long-term contracts (greater than 5 years) which might be needed to finance major maintenance or upgrade a facility.[19] For example, many existing generators could upgrade their facilities to provide more flexibility – which may be less expensive than building a new resource – specifically to provide the fleet sufficient flexible resources. Further exacerbating this problem, utilities are currently authorized to spread the cost of contracts with new resources to all "benefitting" customers, essentially socializing the premium cost of new generation. That mechanism referred to as the "Cost Allocation Mechanism" (CAM) was designed to support new generation, but it was not designed initially to support long-term contracts with existing generation.[20]

The oversupply of system RA capacity drives the market price for existing capacity toward cost, which is significantly lower than the cost of new entry (i.e. new capacity). As shown below, oversupply in the markets for RA capacity appears to be keeping capacity prices at or below fixed cost for many existing natural gas fueled resources.

CPUC staff reviewed the price of RA contracts used for compliance in the 2011 RA compliance year in the CPUC's 2011 RA Program Report. The cost of RA contracts is very competitive, for example the median price for RA-only capacity is shown as $2.20 kW/month in Table 2, column 1. The maximum price for RA-only capacity was $12.25 kW/month, and 85 percent of contracts were under $4.00 kW/month. The table also has columns that show RA prices for NP26 (the northern part of the state), SP26 (the southern part of the state), the CAISO system, and then local areas.

Table 2. Summary statistics of RA Prices by category

	RA/ Capacity only	NP26	SP26	CAISO System	Local	NP26 Local	SP26 Local
Median	$2.20	$2.00	$2.25	$1.65	$2.68	$3.30	$2.50
85 percentile	$4.00	$4.00	$4.23	$3.27	$4.42	$5.50	$4.25
Max	$12.25	$9.95	$12.25	$9.95	$12.25	$9.00	$12.25
Number of contracts	450	157	293	140	300	39	261

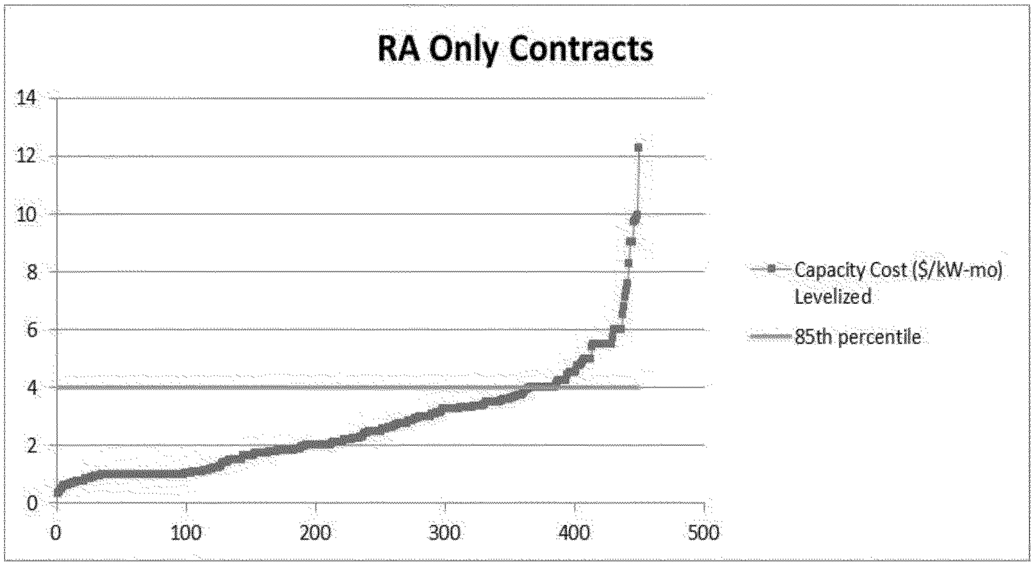
Source: All prices represent nominal dollars in kw/month. 2011 RA Report, released February 5, 2013, page 22.

19 While PG&E, SCE, and SDG&E have the ability to contract with resources for 5 years or more in duration, this requires an application to the CPUC for approval rather than falling under their AB 57 upfront procurement rules.

20 See D. 06-06-027.

The same basic RA price data is shown in Chart 2, in a different format. Chart 2 shows that RA prices in the top 15 percent of prices can be 2-5 times the median price. Note the steep right hand side of the curve; each dot represents one of the 450 contract prices surveyed in the report.

Chart 2. Breakdown of prices paid for RA only contracts in data set



Source: CPUC 2011 RA Report, released February 5, 2013, page 23. Shows data from 2012 Energy Division survey of IOUs and ESPs, September 2012.

Energy prices in the short term energy markets are relatively low. Energy prices are usually expected to pay for marginal operating costs (including operation and maintenance costs related to operations), but not necessarily fixed costs. Low energy prices are due to a combination of factors: significant increases in resources with very low (to zero) marginal costs (e.g. wind and solar), excess capacity and some new very efficient natural gas resources. In the near term, with relatively low energy prices and more capacity available than needed to meet the 15-17 percent planning margin, some existing fossil plants may find it uneconomic to continue operating, even though their capacity may be needed for reliability in just a few years.

Some generators are needed for capacity, but are expensive to run and will only be called on to run for energy a few times a year. More efficient units will be able to run in the energy markets more often, and may be able to bid lower into the RA markets since they may recover more revenue from the energy markets. This dynamic, in turn drives down RA prices and reduces the revenue inefficient or older plants can attain through the RA market.

Ancillary services markets have not traditionally provided sufficient revenue to support a generation asset. In the future, the need for flexible resources may increase the prices in

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ancillary services markets, but few analysts believe the ancillary services markets will provide sufficient revenues to compensate owners for reduced energy and capacity payments.

Collectively, the above conditions may lead to a revenue shortfall for some resources. Some parties claim resource owners are deferring major maintenance to lower short term costs, which may impair long term reliability. The costs for resources needing to perform deferred maintenance may be higher than can be recovered from the current markets, leading owners to consider retirement. It is unclear, at this time, whether owners would actually retire resources with many years of useful life or would sell the resources, possibly at a loss. We know that in recent years, there have been a significant number of corporate mergers and resource sales among generation owners, but in the absence of further analysis, we cannot tie these occurrences to revenue shortfalls.

Generators make profits when the market price of energy exceeds their marginal cost of production. When the marginal unit producing for the market is inefficient, then efficient producers can collect significant revenues. In theory, as the State's generation fleet is upgraded, less efficient units retire and more efficient units get built, the result being the marginal unit becomes more efficient leaving less revenue for inefficient producers.

C. Desire for Certainty around Flexible Resource Needs and Product Definition

There is a growing understanding of the need for flexible resources to support the electric system's incorporation of a large percentage of intermittent renewable generation. The definition of flexibility, the quantity of flexibility required, and the ability of resources to supply the needed flexibility is still under development.

Definition of Flexible Resources

Flexible resources are generation resources whose operations can be directly controlled (are dispatchable) and quickly start up, shut down, and ramp power output up and down. The exact definitional parameters of a flexible unit are still under discussion at the CAISO and CPUC. For example, some steam units are considered flexible because once in operation they ramp power output quickly, but they have very long start-up times. Some reciprocating engines units are considered flexible because they have short start times, but have little ramping flexibility once started. There is uncertainty on how flexible some demand response programs can be because it is not always clear what load reduction will be obtained, how long the load reduction will be sustained, and how quickly the program will respond. The current CAISO tariff has rules for performance characteristics for existing ancillary services including regulation services, but it is unclear if those rules are appropriate to meet the coming flexibility needs as more intermittent generation enters the system.

Quantity of Flexible Resources Needed

The electric grid needs to be in balance at all times. The existing distribution system is designed to absorb minor fluctuations in generation supply and customer demand. In addition, the system design ensures capacity reserves exist to compensate for unexpected generator outages or transmission line failures. The CAISO has raised concerns that the large amounts of intermittent, primarily wind and solar, resources currently under contract to come on on-line in the next few years, will stress the system in new ways. The added stress creates a need for new and/or additional fast ramping flexible supply resources.

The sizeable supply fluctuations from large scale intermittent resources (e.g. wind and solar) in addition to well-understood large changes in customer load over the course of a day, require dedicated resources that can be dispatched when the wind stops or the sun goes down. Potentially thousands of MW of solar resources will start and cease producing at approximately the same time each day. To keep the system in balance, resources need to be operating to meet customer needs until the solar resources start producing power and then have the ability to quickly shut down as solar resources come online (otherwise the solar resource would not be displacing anything). These other resources must then be available again to quickly start-up as the solar resources stop producing once the sun goes down.

The current LTPP proceeding, with the assistance of the CAISO, is analyzing how the electric system will operate using the load and resources expected to exist ten years in the future. In 2013, we expect the analysis to show whether the expected resources will be adequate to balance the system and if not, what additional operational requirements – i.e. what amount of flexible capacity -- will be needed to safely and reliably operate the system under various scenarios. Analysis for the 2010 LTPP proceeding showed considerable variation in the quantity of flexible capacity deficient during the planning horizon.[21] In 2010, most scenarios showed that the expected system would have sufficient flexibility in the fleet to accommodate the intermittency, while other scenarios showed a net need that could trigger an authorization for new resources. Given the range of needs, a joint party settlement filed in late 2011 and adopted by the CPUC in April 2012 recommended deferring need authorization for flexible capacity until the issue was studied further in the context of the next LTPP cycle, now ongoing.

Challenges with Conducting Flexibility Analysis

To conduct the operational modeling analysis required to determine how much flexibility is required by the electrical system over the course of the planning horizon, planners need to make a range of planning assumptions and apply those assumptions to the planning scenarios. The LTPP planning forecasts are extremely complex analytical exercises made

[21] In April 2012, the CPUC adopted a multi-party settlement in the last Long-Term Procurement Proceeding (2010 LTPP) that stated "There is general agreement that further analysis is needed before any renewable integration resource need determination is made." (Settlement Agreement at 5, quoted in D. 12-04-046, p.6).

even more complex lately by the current spotlight on the modeling output specifically related to sufficiency or deficiency of operational flexibility in the projected system fleet.

The extent of the need for any resources—system, local, or flexible - is based on large number of assumptions on how the California economy will perform and drive energy demand, how preferred resources (energy efficiency, demand response, renewable, combined heat and power) will be funded in the future, which existing resources will remain in operation, and how all of these resources will perform in the future. CEC, CAISO, and CPUC staff have been working on common planning assumptions for many years and have made significant progress, but differences still exist. These differences are partly explained by the various missions of the organizations and the amount of risk each organization is comfortable including in their forecasting. While the three organizations are generally in alignment on their planning assumptions based on years of working together – this emerging need to analyze flexibility requirements and determining related planning assumptions— is one of the key areas where further hard-work is needed to drive towards consensus.

With specific respect to flexibility, the uncertain definition of flexibility[22] makes it challenging to determine how much flexibility may be needed today (let alone how much will exist in the future given the various scenarios), or even determining what flexibility exists in the current resource fleet. Making matters worse, many existing resources have the ability to operate flexibly, but do not offer their unit's flexibility to the CAISO in the current energy market design. As discussed above, changes to the CAISO markets-including the introduction of the Flexiramp product, may provide some financial incentive to generation owners to bid their flexibility services into the CAISO market. However, many existing flexible resources are self-scheduled into the CAISO markets, meaning that the CAISO cannot use their flexible attributes to meet today's operational needs.[23] In sum, the existing fleet's flexibility is challenging to assess accurately, in addition to the need for planners to overlay a range of demand changes, resource addition and retirement assumptions, and then assess how much flexibility will be available (or needed) in the future.

[22] Various definitions of "flexibility" have been proposed, they include variations on the required duration of upward or downward ramp, the ramp rate per minute, and the frequency of ramping capabilities. The definition adopted will directly affect which existing resources qualify, which existing resources can be retrofitted to qualify, and which types of future resources should be developed to meet these needs.

[23] Resource owners have expressed a number of reasons why they self-schedule rather than include the resources in the CAISO optimization process. Some are concerned that if their units are dispatched by the CAISO: resources may be dispatched in ways that the unit cannot function, both causing penalties and damaging their ability to function; and dispatching resources to take advantage of flexibility will increase operating costs, but generators will not be compensated for these costs.. The CAISO has been working on addressing these concerns, but too many resources are still self-scheduled and not available to meet flexibility needs.

D. *Insufficient Certainty on the Quantity of Capacity that will be Available beyond One Year-Ahead RA Showings*

The RA program requires load serving entities to file an annual report of capacity resources under contract on year forward basis to the CPUC and the CAISO. A persistent complaint about the RA program is that there is no visibility – beyond one-year – on the expected availability of capacity resources to meet the capacity needs in future years.

Through utility procurement plans and filings, the CPUC can determine that a significant amount of resources are under contract multiple years forward, or are owned by utilities. However, that confidential procurement information is not available to the CAISO. Although the specific contracts are not known, it is well known (to the CAISO and others) that the utilities layer in the procurement of their capacity resources, using contracts ranging in time from 1 month to 25 years.[24] While this layering occurs, there are large amount of capacity resources that are not under contract for future years but are expected to be under contract in those years or available to meet capacity needs in those years.

Generators understand that if a utility has a certain percentage of its RA requirement "open" for the compliance year 5 years in the future, there is a good chance the utility will be doing additional procurement to fill in its future needs. However, in a situation where there is a 40+ percent reserve margin and multiple utilities with significant forward open positions, there are a large number of generators without forward contracts – many of which will never have contracts. Generators faced with this uncertainty sometimes argue that the utilities and other LSEs cannot just assume that generators will hang around waiting for future contracts, some may retire in the interim.

The CPUC's LTPP assumes the majority of existing resources will continue in operation, obtaining new contracts when their current contracts expire and in some cases relying on sales into the spot markets. The LTPP makes some assumptions about planned retirements, based on OTC requirements or other age factors. However, CAISO and other stakeholders have expressed concerns that this LTPP assumption may not be valid, and the CPUC should not assume that all resources out of contract that are not obvious retirement candidates will stay online. The argument follows that critical reliability resources could choose to retire because they lack adequate revenue.

Stakeholders concerned about this outcome of untimely retirements leading to reliability concerns quickly cite an obvious solution(s) or alternative: place multi-year forward capacity obligations on load serving entities and/or require a centralized clearing market for all forward capacity resources.

In direct response to an insufficient level of quantity of capacity that will be available beyond one year-ahead RA showings, a CAISO stakeholder processes developed the

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[24] Electric Service Providers, Community Choice Aggregators, and Publicly Owned Utilities also contract for resources, but their contracts longer than one year are not visible to CPUC staff.

proposed CAISO tariff amendment, currently under consideration at FERC, the Flexible Capacity and Local Reliability Resource Retention (FLRR). (See Section II.C. above).

IV. Options for Moving Forward

Currently, the CPUC is considering at least two modifications to the existing framework. We have two ongoing proceedings (LTPP, R. 12-03-014 and RA, R.11-10-023) in which parties have raised concerns that the one year forward resource adequacy program should be improved in at least two respects. First, it should take into account the need for some level of resource "flexibility" in order for the system to be operated reliably as a result of the addition of substantial intermittent, renewable resources to the grid, and second, the current, one year forward RA procurement requirement applicable to all load serving entities should be extended to a multi-year timeframe.

The CAISO maintains that the current one year-ahead forward requirement does not provide it with adequate assurances that the resources needed to operate the system will be available in future years. Generators maintain that the current one year forward requirement does not provide them with adequate financial signals that they are "needed" in the future. However, the current system has thus far been sufficient to ensure reliability and strikes a balance between rates, reliability, and investment returns to generation owners.

There are also a variety of potential additional options to modify the resource planning and procurement process. The CPUC could add, prioritize or modify the scope of existing proceedings to consider any of these options. The CPUC could open a new proceeding to consider action on any of these options. **No staff recommendation on the options or the procedural path forward is included in this document at this time.**

A. Create a Multi-Year RA Requirement with (or without) a Centralized Capacity Market

This option would essentially reconsider the CPUC's 2010 decision[25] and consider adoption of a multiyear RA obligation with or without a centralized capacity market. Similar to the current one year RA requirement, the CPUC could actively consider a multi-year RA requirement, whereby load serving entities would be required to demonstrate that they have commitments to supply resources to the CAISO in a future time period. Instead of making commitments one month or one year in advance, under a multi-year requirement the LSEs would be required to commit to resources for a longer time period. The reconsideration could include consideration of a multi-year RA requirement for system, local, and/or flexible capacity. The CPUC's 2010 decision had not contemplated a multi-year requirement for flexible capacity, only system and local.

[25] D. 10-06-018.

A multi-year RA requirement has been opposed by Direct Access providers as being inconsistent with their business model. A particular concern for them is the necessity to make financial commitments for a multi-year period without having a commensurate commitment from their customers. Given oversupply of system capacity, it is not obvious that a Direct Access provider will be able to sell its excess capacity if it finds itself long in a future year.

A centralized capacity market, sometimes referred to as a government-run or administratively-run capacity market, may resolve the objections of Direct Access to a multi-year RA requirement. For example, the Eastern ISOs have the ISO enter contracts three years in advance and allocate the cost to load serving entities in the delivery years, in proportion to the load serving entities load share. The ISOs assume the obligation for purchasing the capacity via the centralized market, and then the Direct Access providers (or any LSE) pay for the capacity according to load share in the actual year of delivery.

There are several alternative approaches to multi-year RA obligations in place in the Eastern ISOs. The PJM and ISO-New England models include a 3-year forward, mandatory annual auction, with 3 subsequent incremental auctions to account for demand changes. The capacity markets require a 1-year commitment period of a capacity resource and they clear for both system and local capacity. (Sometimes "system" is referred to as regional transmission operator-wide, RTO-wide; sometimes local is referred to as transmission-constrained.) The New York ISO (NY-ISO) has voluntary, month-ahead and seasonal 6 month commitment periods.

A few key points about centralized capacity markets, each of which can be debated at length by supporters and opponents of such markets:

- Centralized markets allow for incremental (or decremental) procurement of capacity for load shifting and revised load forecasts. This feature is generally considered friendly to capacity resources with short lead times, such as storage, demand response, targeted energy efficiency, or incremental capacity additions to existing plants. This feature also means higher costs to ratepayers because ratepayers may pay for some 'insurance' to purchase capacity that is later revealed to not be needed (if the forecast goes down).
- Centralized markets ensure resources are contracted for in future years, providing some marginal increase in certainty around reliability margins.
- Centralized markets may provide for some advanced warning of retirement of older generation units.
- Centralized markets require that ratepayers assume a large amount of risk for forward procurement obligations, instead of the market.
- Centralized markets are criticized for overcompensating generators – particularly existing generators, especially if all resources are paid the market clearing price. The rules around bidding and clearing the market, including resource counting rules and bidding rules (for example, Minimum Offer Price Rules, MOPR) become extremely important.
- Centralized markets are regulated by the FERC, which would represent a loss of State control over some key resource planning decisions.

- Centralized markets have mixed reviews in terms of the promotion of preferred resources, especially renewables, due to the fact that the State has a policy preference for renewable capacity but a FERC-jurisdictional capacity market may or may not have bidding and counting rules that allows for favorable treatment of renewables.

The Eastern ISOs do not currently have markets for operational characteristics, i.e. ancillary services that would include flexibility. This design reflects that the Eastern markets have not generally been concerned about the long-term supply of ancillary services. California has a variety of options to consider:

- A multi-year forward RA obligation without a centralized capacity market; the obligation could be for 2, 3, or more years forward, and could cover system, local, and flexibility capacity - or only system and local.
- A multi-year forward RA obligation with a centralized capacity market. The centralized market could purchase local and system capacity and require some flexible resources, or purchase only flexible resources.

B. Resource Life Contracts

Renewable resources are typically contracted for their design life. A similar structure could be promoted and used for the non-renewable resources (primarily natural gas fueled). Utilities and other load serving entities would construct utility owned plants or offer 30+ year contracts for new facilities and would enter into contracts for the remaining life of existing facilities. These contracts could be for the total output of the resources or could be only for resource adequacy commitments.

A variation on this option is requiring resource life contracts only for flexible resources.

C. Establish a Process for Bilateral Contracting and Cost Allocation for Existing Resources

The CPUC could establish a process to order a utility to enter into a contract for capacity from a specific resource that is critical to grid reliability, but asserts it will retire for economic reasons. If this is likely to occur multiple times, the CPUC could establish a more generic process and cost allocation methodology for such contracts. Currently, the cost allocation mechanism is used for new resources. However, if the CPUC found that existing resources needed long-term contracts (to provide incremental capacity, finance a long-term upgrade for flexible capacity, avoid an early retirement, etc.), then the CPUC could design a procurement and cost-allocation mechanism to achieve that objective. This option might be able to create a CPUC and market based procurement mechanism to avoid the need for a longer-term CAISO-based backstop mechanism.

D. Develop a CPUC Procurement Mechanism and Coordinated CAISO Backstop Procurement Mechanism to Prevent Retirements

There is currently a CAISO proposed tariff amendment to attempt to prevent retirements, FLRR. (See Section II.C. above). The CPUC recently opposed the initiative at FERC, but one option would be to modify the CAISO backstop mechanism tariff (as proposed) to meet some of the concerns expressed by the CPUC. This option would involve the CPUC and CAISO collaborating to create a CPUC procurement mechanism to prevent retirements that could harm reliability, and then having CAISO backstop that procurement mechanism once it is in place.

E. Promote Greater Development of Preferred Resources with Short Lead Times

The discussion regarding the potential need for new capacity in a few years has focused primarily on means to assure ample fossil generation in the future. However, State policy, in particular the loading order for new resources, requires the CPUC to consider preferred resources rather than just fossil. There is ample room for additional development of preferred resources, in particular distributed generation, demand response and energy efficiency programs. For example, only 4 percent of PG&E's residential customers are signed up for Air Conditioner Cycling and other demand response programs. These resources tend to have very short lead times, months rather than years. In addition, some demand response and energy storage resources are, fast responding, and may be able to provide a significant amount of flexibility for the grid.

As an alternative to fossil plant reliance, the CPUC could consider whether significant additional amounts of these preferred resources should be sought(as well as their appropriate capacity or flexibility value) to meet the forecast needs three to four years in the future. A consideration should be whether expanding preferred resources may exacerbate the problem of inadequate revenues for fossil resources seeking capacity and energy payments. Finally, greater discussions between the CPUC and CAISO may be useful to develop retail programs with CAISO requirements. By aligning these programs more directly with CAISO requirements, this may assist in facilitating the CAISO to account for demand-side resources into their planning projections.

F. Rely on Market Forces with Modest Changes to Existing Programs

The risk of premature retirement of certain generation assets is underlying much of the current concerns, but may not be the root cause of the actual problem. It is uncertain that there will be any capacity shortage in a few years. Considering the current market conditions, as well as the near term 5 year planning period, a variety of existing resources may not be competitive given how much the current forecast supply exceeds forecast load. Policy makers should consider whether to allow the market process to work, and accept the results that occasionally a plant may be uneconomic and retire early. This situation may occur, especially since the CPUC may need to continue to authorize new resources to meet changing needs, such as any need for flexibility, to reduce greenhouse gas emissions, to handle SONGs uncertainty, or ensure local reliability in any of the local areas.

There are a number of actions the CPUC and the CAISO could undertake in the near term that do not require significant changes or creation of new markets and backstop authority, that could mitigate the current problem and reduce the chances for it reoccurring. Some of these relatively modest changes include:

Seek Alignment between CPUC and CAISO Planning Assumptions

This option requires the CPUC and CAISO to work harder on aligning planning assumptions. This option would include the CPUC running a scenario that replicates the CAISO-preferred assumptions and vice versa. For example, the CAISO would run the entire LTPP base scenario in its Transmission Planning Process, and the CPUC would run a "replicate the transmission planning process" scenario in the LTPP.[26]

Make Utility Long Term Procurement More Visible to the CAISO

The CPUC could establish a method for utility forward procurement to be demonstrated to the CAISO. Under current rules, CAISO only sees capacity procurement data in the one year-ahead RA showings. Requiring greater transparency of the utilities to share otherwise confidential forward procurement data may help reduce the CAISO's fears about additional risk of retirement if the CAISO staff knew with more certainty what resources are already under forward contract obligations. Energy Division Staff has communicated the CPUC's existing program structure to the CAISO and has encouraged the CAISO and utilities' staff to discuss the forward procurement done by utilities.

Revisit the Planning Reserve Margin

The CPUC could consider changing to a new planning standard if the current standard raises reliability concerns too frequently. The analysis used to adopt the current planning margin (15-17%) did not include consideration of flexibility needs. Also, a different planning margin is used for local areas (peak weather, plus the loss of the 2 largest contingencies). The CPUC could consider revising the planning reserve margins based on the flexibility analysis currently being performed by the CAISO for the 2012 LTPP. This may involve modifying the current percentage, targeting resources by location, or

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[26] The 2012 LTPP proceeding's Assigned Commissioner's Ruling on Planning Scenarios, issued September 20, 2012, already contains a "Replicating Transmission Planning Process" scenario in order to more closely align with CAISO assumptions.

creation of new requirements. If new requirements are established, a mechanism for procuring resources will also need to be established.

Strengthen Flexible Resource Procurement Obligations

The CPUC could strengthen the requirement for procuring flexible resources in the LTPP, the RA program, and the other resource proceedings (although in reality these resources are often already procured and preferred). In LTPP decisions, the CPUC has requested utilities consider flexibility needs when contracting for new generation, but has not made an explicit requirement on flexibility attribute of new resources, since flexibility needs are still uncertain. (See Section III.C. above.) The continuing efforts in the LTPP proceedings may provide a basis for such a requirement in the future.

The current RA proceeding[27] directs the CPUC staff and the CAISO to begin efforts to finalize a framework for filling flexible capacity with the intent to adopt a framework for implementation in the 2014 Resource Adequacy compliance year. The Energy Division and CAISO are holding workshops for defining the implementation details of incorporating flexible capacity in the Resource Adequacy program.

V. Conclusion

The CPUC's decisions surrounding resource adequacy and its interplay with the long term procurement processes are some of the most disputed policy decisions that the organization makes. Future decisions to stay the course or modify key aspects of energy market design will be no less controversial than past ones. Should a new power plant be approved for reasons, such as greenhouse gas reductions, operational flexibility or job creation, even if unneeded for traditional reliability? These types of decisions, while somewhat subjective in nature, rely on forecasts of future demand, resource development and operation, and are always likely to be inexact in hindsight. While it may be possible or desirable to have a more efficient or a different approach to system planning, any policy framework will still remain subject to the realities of the market, iterative policy tweaking and painstakingly negotiated decisions.

Depending on one's perspective of the current challenges, the options for addressing the challenges come into focus. The CPUC needs to carefully consider the effects of staying the course, including the real costs and impacts of status quo versus significant regulatory framework change. The CPUC also needs to consider how any proposed modifications to the current regulatory structure may impact ratepayer costs and improve or worsen the balance of risks between ratepayers and resource owners.

[27] D. 12-06-025

Appendix A

A. Electric Generation Markets in California

The production and delivery of electric power in California presents significant complexity to market participants, utilities, regulators, and investors[28]. One method of analysis is to identify unique parts of the electric system, but it must be emphasized that each part of the system is inter-related with other parts. It is no longer possible, if it ever was, to discuss distribution, transmission, and generation as separate components. An analysis on one component must account for the others.

Electric Markets in California include a variety of energy, capacity and ancillary service markets:

- Real-time, hour-ahead, and day-ahead markets for energy, measured in kWh, administered by the CAISO
- Forward bilateral and exchange-based markets for energy, measured in kWh. Forward energy can be procured through a tolling contract (right to operate a plant) or a call option contract (without a specified underlying resource but callable at a certain implied market heat rate).
- Ancillary service markets: spinning reserve, non-spinning reserve, regulation
- Non-market purchases for ancillary services: voltage support, black start
- Decentralized capacity markets for system and local capacity where buyers/sellers transact to meet CPUC requirements for month-ahead and year-ahead resource adequacy (RA) measured in MW. Capacity from existing resources is most often purchased in contracts lasting less than five years. Capacity contracts may include energy as well, or they may be "RA only" contracts, meaning the
- New generation capacity markets where buyers (mainly utilities) and sellers (mainly developers) transact for long term (5 or more years) commitments of sufficient price and duration to build new generation capacity. New generation contracts usually include rights to both the capacity and the energy of the resource, although renewable generation contracts typically focus on the energy output (measured in kWh or MWh) and natural gas fired generation contracts typically focus on the capacity (measured in MW). Most California new generation contracts bundle both energy and capacity in one transaction.

Because one generator can produce energy, capacity, and ancillary services, simultaneously in some cases, pricing and marketing individual products is difficult and subject to manipulation of joint costs. A single resource can expect to recover some costs from capacity, energy and ancillary service markets. Depending on the type of contract, the buyers of units or the sellers of units bear more or less risk as the market experience natural fluctuations due to daily demand, weather, and cost of fuel (primarily natural gas).

[28] In this appendix, 'investors' means non-utility parties investing in generation resources. The three large utilities in California (PG&E, SCE, and SDG&E) are by definition investors in generation resources, but for the purpose of this paper they are separately referred to as utilities.

All of the fluctuations determine market clearing prices and ultimately prices (as well as CAISO's Integrated Forward Market) determine which units run and which sit idle.

Some names of typical energy related contracts include:

- Tolling Agreements: The buyer has the right to the capacity of a plant (can use it for RA), and it can also dispatch the resource, but must also supply the fuel.
- Energy-Only Contracts: Some contracts are for specific energy products for specific hours over a specific time period, such as the delivery of 50 kWh for 16 hours per day, seven days a week for a specified period, such as 4 months (7 x 16 contract). The buyer has the definite right to a certain amount of energy for the specified periods. These contracts do not typically have capacity (i.e. the buyer has to procure RA capacity).
- RA-Only Contract: Buyer can only use the unit for RA compliance purposes but has no right to use, call, or schedule the energy in the energy markets. Every resource used for RA compliance purposes – regardless of the type of contract – is required to have a must offer obligation into the day ahead CAISO energy market.

B. Investment in New Resources

In a perfectly competitive market, investors determine if new resources are needed. When investments are made, the investor's capital is at risk, and the investors incur losses if the new resources are not, in fact needed. In the California electricity markets investors have determined that the risk is too high without a contract that guarantees recovering most of the initial investment. There are multiple reasons for this situation.

Capacity payments in a market driven by only a one year (short term) regulatory requirement can be considered unreliable. A limited amount of capacity is required by government to ensure reliability. Government forecasts and counting can change, year to year, for a variety of reasons that cannot be easily predicted, such as political climate. Factors outside the control of the investor, and not easily forecast can raise or lower the price of capacity.

The determination of how much revenue that a resource needs to recover from capacity payments varies by resource, and by uncontrollable variables. For example, in a year with lots of snow, a lot of inexpensive hydro power is available thereby reducing the demand for other resources. The reduced energy revenue increases the amount of fixed costs that need to be recovered by capacity payments. Resource owners must calculate these variables when making bids into capacity auctions knowing the high bidders will not receive a contract and will get no capacity payments.

To build a new resource an investor needs to forecast the amount of new capacity needed when the proposed resource[29] will enter the market and forward through the life of the asset. The basis for the forecasts depends on a number of variables that can change

[29] Permitting and constructing a new natural gas fueled combined cycle generation turbine takes 3-7 years.

significantly. For example, the economic downturn caused a significant downturn in forecast demand, affecting both the price of energy and the resource ability to sell its product at all. In addition, the amount and effectiveness of energy efficiency programs five and ten years forward has been controversial. If funded and effective, energy efficiency can significantly reduce the need for new supply side resources. Similar issues can be found with demand response programs, distributed generation programs, the RPS, and the political processes that may mandate utility investment in various resources. Further, the investor must calculate the price of fuels both for the proposed resource and competitors, which poses risk because fuel cost can be highly volatile, especially natural gas. A high natural gas price makes an efficient generator more competitive in the energy markets against generators using the same fuel, but a low natural gas price dampens this effect.

Investors also must consider that while hydro, wind and solar resources have a very high construction cost, the operational costs are minor allowing variable costs to approach zero. Nuclear power plants have a similar situation of very high initial costs, although their operational costs are higher. While the construction costs associated with natural gas fueled resources are not as high as wind and solar, they have significant fuel costs. At the same time, these resources are flexible and are able to be dispatched when needed. Therefore, while hydro, wind, solar, and nuclear resources are generally considered must-take resources, where the grid takes all the power they produce, natural gas resources are dispatched to meet needs when the price of power exceeds their variable costs. This dynamic has a significant impact on the revenue generated from the energy markets.

The RPS program is focused on supplying 33 percent of energy needs from renewable resources. The RPS law creates the need for renewable resources. Renewable resources generally provide some capacity that adds to the general supply. Contracts with new large renewable resources are generally for the life of the resource, so 20, 25, and 30 year contracts are common. The Renewable Action Mechanism and renewable feed-in programs allow 10, 15 or 20 year contracts, although all contracts to date have been 20 years.

In renewable contracts, the developer/investor takes the risk of obtaining permits, bringing the resource on-line, and ensuring the facility remains in operation. The utility takes on the price risk and the need risk. The utility does this by agreeing to pay the contract price for delivered energy for the life of the contract, regardless of the value of the energy and capacity in the markets, and regardless of whether the utility has a need for renewable resources in the delivery year. If the facility performs at a lower capacity factor than planned, or the equipment fails, the revenue for the developer/investor may be insufficient to cover investment costs, if the output exceeds expectations increased profits are earned. In a similar fashion, the utility commits to purchasing the energy the resource produces. Therefore, the utility takes the risk that newer technologies may be less expensive and changes in power demands (or renewable energy resource availability) may make the plant unnecessary.

The rules and duration of contracts with existing renewable resources are less defined. Most existing renewable resources enter bilateral contracts. These contracts vary on a number of factors, but are generally less than ten years.

Appendix B

A. 2012 LTPP Base Scenario (2012-2022)

This table contains the more detailed assumptions used in Chart 1. Managed demand net load is the result of taking the California Energy Commission's demand forecast and adjusting for additional demand-side programs, such as energy efficiency planned but not yet funded. The net supply accounts for the capability of forecast resources (existing + additions – retirements) to provide capacity at the system peak. The net system balance is the share of resources exceeding demand, and the CPUC currently has set a minimum planning margin of 115%.

	2012	2013	2014	2015	2016	2017	2018	2019	2020	2021	2022
Demand (MW) *											
IEPR Net Load	47,743	48,870	49,577	50,240	50,931	51,625	52,296	53,000	53,674	54,299	54,871
Inc. EE	7	179	394	740	1,094	1,420	1,633	2,019	2,401	2,758	3,103
Inc. Small PV	79	158	237	316	395	474	552	631	710	710	710
Inc. D-CHP	-	-	-	-	-	-	-	-	-	-	-
Managed Demand Net Load	47,658	48,534	48,946	49,184	49,442	49,731	50,110	50,349	50,562	50,831	51,058
Supply (MW)											
Existing Resources	50,442	50,442	50,442	50,442	50,442	50,442	50,442	50,442	50,442	50,442	50,442
Resource Additions	194	2,909	6,797	7,926	8,533	8,995	9,382	9,382	9,791	9,791	9,791
Non-RPS	-	2,096	4,746	4,746	4,746	4,867	4,867	4,867	4,867	4,867	4,867
RPS	194	812	2,050	3,180	3,786	4,128	4,515	4,515	4,924	4,924	4,924
Authorized Procurement	-	-	-	-	-	-	-	-	-	-	-
Imports	12,436	13,308	13,308	13,308	13,308	13,308	13,308	13,308	13,308	13,308	13,308
Inc. S-CHP	-	-	-	-	-	-	-	-	-	-	-
Event-Based DR	2,103	2,326	2,499	2,537	2,571	2,589	2,591	2,593	2,595	2,595	2,595
Resource Retirements	1,505	2,179	2,233	3,553	3,625	8,430	9,086	9,086	14,981	14,987	15,017
OTC	452	1,126	1,126	2,446	2,446	7,252	7,252	7,252	13,146	13,146	13,146
Nuclear	-	-	-	-	-	-	-	-	-	-	-
Solar + Wind	-	-	-	-	-	-	-	-	-	-	-
Other Renewables	-	-	-	-	-	-	-	-	-	-	-
All Hydro	-	-	-	-	-	-	-	-	-	-	-
Other Non Renewables	1,053	1,053	1,107	1,107	1,179	1,179	1,835	1,835	1,836	1,842	1,871
Net Supply	63,671	66,807	70,814	70,661	71,230	66,904	66,637	66,639	61,155	61,149	61,119
Demand (GWh) **											
IEPR Net Load	234,112	236,579	239,184	241,726	244,321	246,889	249,406	252,603	255,791	259,001	262,284
Inc. EE	78	810	1,968	3,628	5,368	6,975	8,088	9,811	11,501	13,186	14,783
Inc. Small PV	240	480	720	959	1,199	1,439	1,679	1,919	2,159	2,159	2,159
Inc. D-CHP	-	-	-	-	-	-	-	-	-	-	-
Managed Energy Net Load	233,794	235,289	236,497	237,138	237,753	238,474	239,639	240,874	242,131	243,656	245,342
Net System Balance	16,013	18,273	21,868	21,477	21,787	17,173	16,527	16,290	10,593	10,318	10,062
	134%	138%	145%	144%	144%	135%	133%	132%	121%	120%	120%

Source: D. 12-12-010, Appendix C, page C-1:
http://docs.cpuc.ca.gov/PublishedDocs/Published/G000/M040/K642/40642804.PDF